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Estimating Power System Interruption Costs: A Guidebook for Electric Utilities

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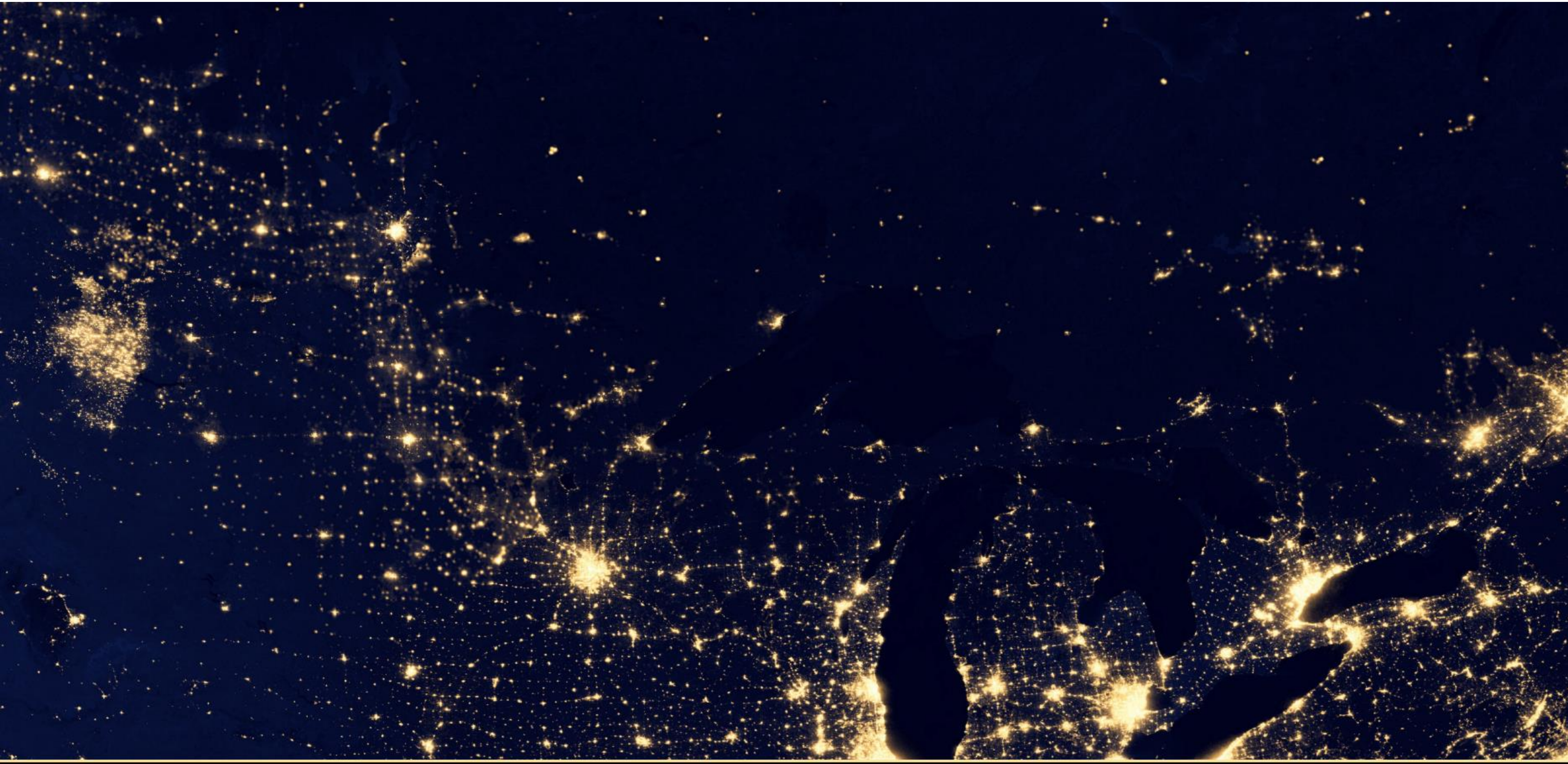

Estimating Power System Interruption Costs

A Guidebook for Electric Utilities

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Estimating Power System Interruption Costs: A Guidebook for Electric Utilities

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U.S. Department of Energy

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Acronyms and Abbreviations

AMI	Advanced Metering Infrastructure
BCA	Benefit-cost Analysis
C&I	Commercial and Industrial
CAIDI	Customer Average Interruption Duration Index
CCA	Community Choice Aggregation
CDF	Cumulative Density Function
CIC	Customer Interruption Cost
DER	Distributed Energy Resource
DG	Distributed Generation
DRP	Distribution Resources Plan
DSIP	Distributed System Implementation Plan
GDP	Gross Domestic Product
GLM	General Linearized Model
ICE	Interruption Cost Estimate
LBNL	Lawrence Berkeley National Laboratory
LOLE	Loss of Load Expectation
MSA	Metropolitan Statistical Area
NPV	Net Present Value
NY PSC	New York Public Service Commission
OLS	Ordinary Least Squares
OMS	Outage Management System
PG&E	Pacific Gas and Electric
PSE	Puget Sound Energy
PV	Photovoltaic
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAIVI	System Average Interruption Value Index
SMB	Small/Medium Business
T&D	Transmission and Distribution
TOU	Time of Use
WTA	Willingness to Accept Payment
WTP	Willingness to Pay
VOS	Value of Service

Executive Summary

Utilities are constantly making improvements to their infrastructure and operating protocols to maintain or enhance the reliability and resilience of the electric grid. Customer interruption cost (CIC) estimates are useful in assessing and monetizing the economic benefits customers receive from these improvements. This Guidebook for electric utilities explains how to conduct customer interruption cost studies and describes commonly-used, value-based planning methods. The authors intend that this Guidebook will serve as a reference for utility personnel, policymakers and experts in survey design and administration who may be planning to implement CIC studies. It brings the utility industry up-to-date using modern survey technologies, practices, and data analytics to estimate CICs and, ultimately, use the estimates to address both traditional and emerging planning needs.

Customer interruption costs are perhaps the most important input to the process of conducting value-based reliability planning. The objective of value-based reliability planning is to identify economically efficient strategies for which the cost of improving reliability is less than or equal to the benefit from the improvement. The benefit to customers from the improvement is the total of the avoided CICs.

A number of methods exist for estimating the CICs, such as survey-based, market-based, regional economic modeling and blackout studies. Though survey-based methods are more costly, researchers generally prefer them for CIC studies when conducting the studies for the purposes of utility planning. This is due to their historical precedent, accuracy, and versatility for estimating outages lasting 24 hours or less. When conducted properly, survey-based CIC studies can obtain unbiased estimates of interruption costs for shorter duration outages with a reasonable level of precision and while minimizing potential bias. The other methods are more appropriate for other types of studies: market-based methods measure observed behavior, regional economic models estimate impacts from long duration outages, and blackout studies assess impacts from actual widespread blackouts.

A CIC study follows five main steps. Each step is summarized below, along with recommendations for completing the step successfully. The authors based the recommendations on both the literature and experience conducting numerous CIC studies over several decades.

Step 1 - Establish Scope of Study: Determine the types of outages the study should examine (e.g. T&D vs. generation), the range of outage durations to cover, which types of customers to include, specific customer segments to differentiate, and the timeframe for completing the study.

Recommendations:

- Use the underlying purpose for conducting the study to inform critical design decisions. When designing the study, pay careful consideration to how the utility will use the CIC results and any applicable regulatory guidance.
- Determine whether it makes sense to hire a third party to assist with certain or all components of the study.

Step 2 - Develop Sampling Strategy: Develop an effective sampling strategy which minimizes bias, maximizes precision of the interruption cost estimates, and stratifies customer classes based on a range of sensitivities to interruptions. At the same time, survey designers must consider the number of strata to ensure that the surveying process is not too complex for the study team to undertake.

Recommendations:

- Select subgroups within each customer class based on study objectives and/or if there is evidence of significant interruption cost variation.
- Stratify each customer class (or subgroup, if applicable) by the log of usage, which is a proxy for interruption costs.
- Determine the number of strata. Three to five strata strikes a reasonable balance between performance and complexity, in the absence of data from a previous study to guide the decision.
- Use the Dalenius-Hodges method to find the optimal strata boundaries.
- Use Neyman allocation to determine the sample size for each stratum.

Step 3 - Design Survey Instrument: Design survey content and measurement protocols. The study team will use the survey instrument to elicit interruption costs and present information to respondents that can help respondents estimate their costs accurately. Structuring the survey properly will minimize bias by making sure that respondents stay engaged, understand the survey, and keep previous experiences in mind while considering hypothetical outage scenarios.

Recommendations:

- Limit the number of outage scenarios to 5-8 to avoid survey fatigue with respondents.
- For residential customers, implement a two-stage willingness to pay (WTP) measurement technique.

    - First stage: ask customers to consider how the outage would affect their household and to estimate their out-of-pocket and inconvenience costs.
    - Second stage: ask customers to indicate how much they would be willing to pay to avoid the outage.
    - Use the WTP measurement from the second stage in the analysis.
- Assign residential customers the same onset time for all hypothetical scenarios to minimize confusion.
- Conduct small and medium business (SMB) customer surveys using a mixed-mode measurement protocol, with telephone recruitment and email/paper surveys depending on the customers' choice.
- Conduct large C&I studies in-person with personnel from the businesses who are familiar with the facility, operations and cost structure.
- Retired utility account representatives have an ideal background and skillset for conducting interviews.

Step 4: Administer Survey: Conduct the survey using the appropriate approach based on customer class. Allow ample time for recruiting customers, following up multiple times with sampled customers, and collecting data.

Recommendations:

- Allow at least three months to administer the survey and collect the data.
- Provide training to all parties who will be interacting with customers.
- Inform the utility's call center that the study is occurring so that call center reps can verify the study's legitimacy to customers who inquire.
- Provide non-contingent incentives ($2-$5) to residential customers and larger contingent incentives to non-residential customers.
- Leverage utility account representatives to help recruit large C&I customers to participate in the study.
- Account for master metered building tenants after drawing the sample.
    - Survey 5-10 tenants using SMB protocols and scale up to estimate interruption costs for all tenants.

Step 5: Analyze Survey Results: Clean the data and develop customer damage functions that estimate interruption costs over the full range of possible scenarios. Use visualizations to communicate interruption cost estimates and how they vary by the characteristics of the customer, outage, or environment.

Recommendations:

- Drop the highest 0.5% outage cost per unit of energy consumption for the residential and SMB segments as part of the initial data cleaning process.
- Use a two-part regression model specification for the customer damage function. For the first part, specify a probit model; for the second part, specify a Generalized Linear Model (GLM).

1. Guidebook Overview

Utilities are constantly making improvements to their infrastructure and operating protocols to maintain or enhance the reliability and resilience of the electric grid. Customer interruption cost (CIC) estimates are useful in assessing and quantifying the economic benefits customers receive from these improvements. This Guidebook for electric utilities explains how to conduct CIC studies and describes commonly-used, value-based planning methods. The authors intend that this Guidebook serve as a reference for utility personnel, policymakers and experts in survey design and administration who may be planning to implement CIC studies. Generation, transmission, and distribution planners may use it to help evaluate the economic benefits of design alternatives for improving reliability and resilience. Parties in regulatory proceedings may use it as reference for assessing utility infrastructure investments and operations spending in terms of the impacts on the value of service.

> ***Customer Interruption Cost (CIC)***
>
> The economic cost that customers incur when they experience an interruption in electricity service. It is also referred to as the value of lost load (VOLL) or the value of service (VOS).

> ***Outage vs. Interruption***
>
> This Guidebook uses the terms "outage" and "interruption" interchangeably. However, some researchers and industry professionals make a distinction between the two terms. The technical distinction is that an outage will refer to electricity delivery infrastructure or equipment that is not functioning in its full capacity to deliver power. An interruption refers to an electricity service interruption to a customer.

Throughout the Guidebook, the authors refer to a "CIC study team," which could consist of utility stakeholders from the planning organizations listed above—among others—along with the study's project managers and sponsors. The study team may also include departments within utilities responsible for fielding market research studies and third-party consultants and contractors responsible for carrying out CIC studies in the field.

The Guidebook provides some level of detail about the statistical methods and analytical techniques employed in these types of studies, but is not meant to be an exhaustive review of underlying theories and economic models. Readers interested in exploring additional information about particular subjects are provided references to external documents for further research. This Guidebook begins with background on emerging challenges for utilities, value-based planning practices, and methods for conducting a CIC study. Next, the Guidebook introduces the steps necessary for conducting a survey-based CIC study. This section contains a number of recommendations for conducting the study, which are indicated with red exclamation marks in the left margin. The Guidebook concludes with a discussion of limitations with the approach and recommendations for future research. Below is an outline that contains a more in-depth, high-level description of each section.

- **Background:** discusses the key upcoming business challenges and opportunities that utilities face in modernizing their facilities and improving the reliability and resilience of their systems.

This section introduces the concept of value-based reliability and resilience planning and discusses several case studies of successful applications of the approach.

- **Review of Methods:** reviews the methods that researchers use to estimate power system interruption costs, including survey-based methods, which are the primary focus of this Guidebook.
- **Conducting a Customer Interruption Cost Study**: the next five sections review the steps involved in performing a survey-based CIC study. Figure 1-1, below, depicts these five steps in a flow diagram.
    - **Step 1: Establish Scope of Study:** discusses the process of choosing the types of customers and interruption scenarios to include in the study. Step 2: Develop Sampling Strategy**:** explains how to design the sample(s) of customers to study—in terms of size and stratification—to achieve the study's objectives and maximize precision of the estimates.
    - **Step 3: Design Survey Instrument(s):** describes the main sections of CIC survey instruments and how to structure these surveys to minimize the burden of the surveys on customers and obtain accurate results. It also discusses how survey designs should differ by customer type and size.
    - **Step 4: Administer Survey:** provides guidelines for how to recruit participants and present the survey instrument to the different classes of customers.
    - **Step 5: Analyze Survey Results:** reviews the process of cleaning and validating data, estimating key metrics, and estimating customer damage functions[1].
- **Limitations of CIC Studies:** discusses limitations of the survey-based approach used to estimate customer interruption costs.
- **Research:** concludes with a discussion of possible modifications to CIC methods—both survey refinements and larger methodological changes—to explore and test to improve CIC studies. It also discusses exploring methods for using surveys to estimate costs for long duration outages.
- **Appendix:** contains unabridged versions of the value-based planning case studies introduced in the body of the Guidebook. The appendices also include actual survey instruments that Nexant used for a CIC study.

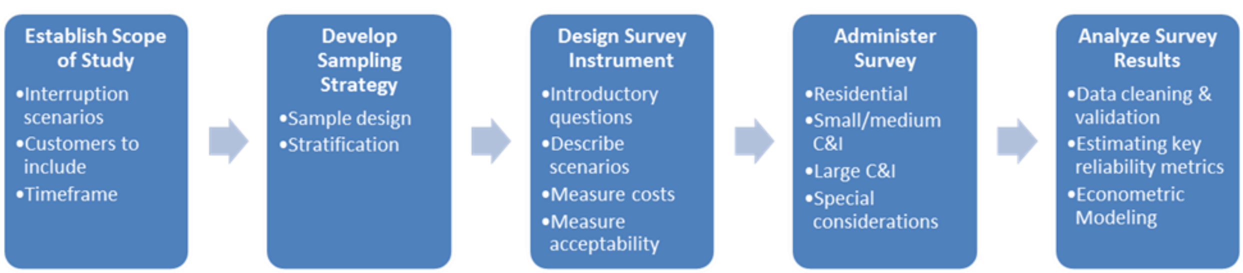

Figure 1-1. Steps for Conducting a CIC Survey

[1] Customer damage functions give utilities the ability to estimate outage costs across a wide spectrum of hypothetical outage scenarios defined by characteristics of the customer, outage and environment.

2. Background

Researchers have been conducting CIC studies for decades using a number of different techniques including customer surveys. By 1995, several utilities had used customer surveys to estimate interruption costs and in that year, the Electric Power Research Institute (EPRI) commissioned Freeman, Sullivan & Co. to develop an Outage Cost Estimation Guidebook (hereafter "the original Guidebook;" see Sullivan & Keane (1995). This reference set forth standard procedures for measuring customer interruption costs using generally accepted surveying techniques. Since that time, several North American utilities have carried out large-scale interruption cost surveys using the original Guidebook's protocols. As CIC data has accumulated, utilities have put it to use in a wide variety of generation, transmission and distribution planning applications including regulatory proceedings.

In 2005, Lawrence Berkeley National Laboratory (LBNL) commissioned the creation of a meta-database of results from CIC studies that used the survey-based methods outlined in the original Guidebook. This database included CIC study data from a significant number of utilities which agreed to participate in the original data collection effort. By 2015, LBNL—working with Nexant—had collected and anonymized data from 34 of these studies to create a meta-analysis dataset containing more than 100,000 customer survey responses; see (Sullivan, et al., 2015). This dataset was used to estimate an econometric model that provides CIC estimates based on utility characteristics such as number of customers and type, and outage characteristics including interruption type, duration, and other conditions. LBNL and Nexant subsequently incorporated the econometric model into an online tool called the Interruption Cost Estimation (ICE) Calculator—now

> ***ICE Calculator***
>
> Online tool for calculating cost of interruptions using the results from previous CIC studies. ("ICE" stands for "Interruption Cost Estimation.") For more information, see Section 2.3.

available at icecalculator.com. Utilities and other stakeholders use the ICE Calculator frequently to calculate customer interruption costs under a number of scenarios.

Since EPRI published the original Guidebook in 1995, the utility industry has changed substantially and survey practices have advanced. Utility planners now face a host of emerging challenges, including:

- growing dependence on electric power to supply new end uses including electric vehicles, home electronics, and personal communication devices
- increased market penetration of behind-the-meter generation and storage
- increased need for resilience given cybersecurity and severe weather threats
- increased availability of new distribution system control technologies that can enhance reliability
- public policy initiatives designed to encourage distributed energy resources (DER)
- increased needs to replace aging equipment with new technological alternatives.

Survey data collection practices and technology have evolved as the above challenges have emerged. For example, response rates to telephone interviewing have dropped substantially for CIC studies over the last few decades. Researchers have witnessed a similar problem with mail surveys, which the original Guidebook recommended for residential customers as well as small and medium C&I customers. Response rates to mail surveys have declined, but not as dramatically as telephone-based surveys. For researchers conducting mail surveys, the bigger issue is that the demographics of respondents have become unrepresentative of the overall population of households. For example, mail survey respondents tend to be older, wealthier, and less mobile than the residential household population as a whole.

Given these challenges with phone and mail-based surveys, social scientists and survey administrators have turned to online resources to advance data collection practices and ensure representative samples. These advances allow for survey data collection methods and results that surpass anything available when the original Guidebook was published in 1995. This revised Guidebook brings the utility industry up-to-date using modern survey technologies, practices, and data analytics to estimate customer interruption costs and, ultimately, use the estimates to address both traditional and emerging planning needs.

2.1 New Challenges for Reliability Planners

For the first 100 years of the utility industry, there was steady growth in demand for electricity supplied from large centralized generation facilities and distributed through transmission and distribution (T&D) systems to end-use customers. Economies-of-scale in the production, transmission, and distribution of electricity strongly favored these large centralized generation facilities—along with T&D facilities capable of moving high voltage power from the generators to customers at lower voltages. The capital that utilities required to develop and operate these facilities was significant and their need for careful load growth analysis and risk management practices led to the creation of long-term planning departments.

As utilities planned for significant growth, their focus was on delivering power reliably, safely, and at reasonable cost for consumers. Utilities assessed cost-effectiveness of potential projects by finding the least-cost alternative (in terms of capital investment and operating costs) that met acceptable performance standards. The drawback to this approach is that different engineering alternatives can exceed the standards by different amounts. A cost-effectiveness analysis alone will not reveal whether investing more to exceed the standards is wise from a cost-benefit perspective. At the same time, the release of CIC studies and improvements to the ICE Calculator (discussed below) has resulted in more interruption cost data available to utilities. Subsequently, a growing number of utilities have started to include avoided customer interruption costs in their cost-effectiveness calculations.

For many years, maintaining adequate levels of grid reliability was a relatively straightforward endeavor. Electricity flowed in one direction: from centralized generating stations on a high voltage transmission system into lower voltage distribution systems and then along to end-use customers. The utility was completely in control of the process from production to end-user. During this time, intermittent energy resources, including wind and solar, had achieved relatively low market penetration. Renewable resources were more expensive than central station delivery systems and clean energy was not a policy priority. Grid operators were also not concerned with cyberattacks, because most of these systems were manually-controlled and the use of online, networked systems was limited. System load grew steadily and vertically-integrated utilities added generating plants, constructed new T&D infrastructure and replaced existing infrastructure when needed to maintain reliability and safety.

Today, reliability planners face emerging challenges different from those of the past, which far exceed the requirements of building and operating the centralized grid. After decades of successful energy efficiency programs and technological advancements, load growth has slowed or declined for many—if not most—utilities. As systems continue to age, maintaining reliability requires utilities to replace a large amount of aging infrastructure. With static or decreasing commodity sales, it becomes more challenging for utilities to recover the costs of these investments. Policymakers in some states have established a number of laws and regulations designed to increase the penetration of distributed energy resources (DERs), such as rooftop solar PV and battery storage. If the penetration of DER reaches certain levels (it varies by circuit), power can flow in two directions on the distribution system. At the same time, increasing risks from extreme weather events, cyber-attacks, and physical attacks have demonstrated the need to improve electricity system resilience—the ability of the electricity system to withstand and recover rapidly from disruptions. Finally, utilities face the task of prioritizing investments to meet all of these challenges. The sections below address each of these points in more detail.

Resilience

Presidential Policy Directive 21 (PPD-21) defines the term "resilience" as the "ability to prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions. Resilience includes the ability to withstand and recover from deliberate attacks, accidents, or naturally occurring threats or incidents."

2.1.1 Replacing Aging Infrastructure

Most T&D infrastructure in use today was constructed in the 1950s-1960s with a 50-year life expectancy. This infrastructure was originally engineered to withstand some degree of severe weather—but increasingly frequent and severe weather may be exceeding the design criteria of these older systems. The need to replace aging infrastructure poses a significant challenge for many utilities today. Not surprisingly, a 2017 survey of utility executives found that addressing aging infrastructure was one of the top five priorities for their companies (PA Consulting, 2017).

Historically, utilities had little need to justify replacing aging assets, because rapid load growth often triggered the need for replacement before the end of the asset's useful life. As the industry has evolved into a period of slow or declining load growth, these older assets are more frequently reaching the end of their life. Accordingly, utilities are forced to be more proactive in assessing asset risk and replacing assets for reasons other than load growth. There is ample evidence that utilities are evaluating the costs to customers as this equipment begins to fail and reliability is impacted. And utilities are also considering the costs and benefits—including avoided interruptions—of new infrastructure. The challenge is that utilities have thousands of aging assets across their service territories—all with some probability of failure within a realistic planning horizon. A key issue for planners and regulators is how to prioritize repairing and replacing these at-risk assets.

2.1.2 Accommodating Distributed Energy Resources

Technological advancements, new financing mechanisms, and public policies have led to increased penetration of DERs on the grid. The efficiency of photovoltaic panels has continued to rise as their cost steadily drops. Financial innovations by PV providers have made the technology more accessible to consumers and battery storage—while less prevalent than PV—has also decreased in cost. Concurrently, federal, state, and local government policies have created incentives, tax breaks, and other conditions that promote the increased adoption of DERs.

> ***Distributed Energy Resources (DERs)***
>
> Smaller power sources positioned closer to demand centers, frequently located on customer sites. They include generation technologies such as rooftop solar PV, small gas turbines, storage and load management resources such as demand response and energy efficiency.

With proper planning, DERs can provide long-term benefits including reliability and environmental sustainability. DERs can also help utilities avoid (or defer) investments in new generation and T&D infrastructure. However, without proper planning, DERs can also impose significant costs on utilities and ratepayers. For example, as the market penetration of DERs increases, utilities may need to upgrade equipment to accommodate two-way flows of power on the distribution grid. DERs can also contribute to congestion on transmission and distribution circuits, causing inefficiencies in how generation is scheduled to meet demand. Utilities and policymakers are currently exploring new ways to encourage customers to site DERs in locations where they will be most valuable to the grid. The

Distribution Resources Plan (DRP) proceeding[2] in California is an example of policymakers and utilities working together to address both the opportunities and challenges that come with DER.

2.1.3 Improving Grid Resilience

Hardening the Grid

Hardening the grid means to implement advanced engineering designs and/or new technology to make the grid less susceptible to damage from extreme weather or from other threats—including cyberattacks.[3] Weather-related events are the leading cause of power interruptions and the number of weather-related outages in the U.S. has been increasing. Campbell (2012) estimates that the annual cost of these events is $20-55 billion. The frequency and severity of natural disasters have been increasing over the past decade and researchers expect the number of interruptions caused by severe weather to increase (Executive Office of the President, 2013). Seven of the 10 costliest storms in U.S. history occurred between 2004 and 2012 and Larsen et al. (2017) project that cumulative customer costs could range from $1.5-$3.4 trillion ($2015) by 2050 without significant changes to the power system (e.g., undergrounding) and increased utility operations and maintenance spending.

In addition to the growing threat from extreme weather events, cybersecurity threats are also increasing (Campbell, 2015). Utilities have become more frequent targets of attempted cyber intrusions, with hackers attempting to compromise the control systems that operate the electric grid. A successful cyberattack on Ukraine's grid systems in December of 2015 showed the consequences of inadequate grid cybersecurity. During this event, 230,000 residents lost power for six hours during the middle of winter. Upgrading critical grid assets with enhanced security measures against cyberattacks has been a priority of the U.S. Department of Energy (DOE, 2017a).

Not surprisingly, it is expensive to adapt existing infrastructure and install new technologies to make the grid more resilient. Utilities are not always able to justify these expenses under conventional T&D planning criteria unless the benefit-cost analysis includes the economic losses experienced by customers—and the regulators are willing to consider these benefits in the screening criteria.

Smartening the Grid

Many utilities are undertaking grid modernization efforts, including investments in technologies that fall under the umbrella of "distribution automation." These technologies facilitate circuit switching, voltage control, fault isolation, and service restoration. These investments can dramatically lower the number and duration of interruptions that customers experience. Utilities are also using these innovations to mitigate degradations in reliability from DERs and other intermittent energy resources. Intelligent switching systems can automatically reconfigure circuits to limit the extent of outages, as well as adapt to changing load conditions and power quality requirements. Other technologies include systems that allow improved DER monitoring, coordination, and control. However, these improvements come at a

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[2] See the California Public Utilities Commission website for more information on this proceeding: http://www.cpuc.ca.gov/General.aspx?id=5071

[3] See Finster, et al. (2016) for examples of how utilities are hardening the grid.

cost and utilities often face the inevitable question of whether their investments are cost justified in light of the benefits they produce.

Making the Grid More Flexible

Power output for intermittent resources, such as wind and solar, is non-dispatchable and inherently unreliable, which makes balancing supply and demand more difficult. Grid flexibility is the ability of power systems to perform this dynamic balancing act. There are a number of investments that can improve grid flexibility. Increasing transmission capacity allows the grid to transport electricity more effectively both within and between balancing areas and thus ease the supply/demand balancing process. The configuration of most of the distribution system in the U.S. is radial, meaning it is designed to transmit power one-way—from substation to end user. Changing the grid architecture to networked allows electricity to flow from one node to another along multiple pathways, thus increasing flexibility.

2.1.4 Prioritizing Investments

A key policy issue for both utilities and regulators is how to prioritize investments designed to address the emerging issues described above. Virtually all utilities use some kind of cost-effectiveness analysis framework, but no framework has been consistently applied and widely-adopted across the U.S. At the core of the problem is selecting a cost effectiveness framework that will ensure that ratepayers and investors simultaneously receive the most value for these investments. LaCommare et al. (2017) conducted a series of interviews with public utility commission staff from various states. Commission staff indicated that stakeholders would benefit from a set of generally-accepted methods when estimating the costs and benefits of investments in reliability and resilience. Without a set of generally-accepted methods, utilities could face difficulties in justifying grid investments that address these new challenges. Underscoring this need is the current regulatory environment, where policymakers have limited appetite for using more utility funds for research, development, demonstration, and deployment (U.S. Department of Energy, 2017). Value-based reliability planning (VBRP), which the next section describes in detail, is an effective approach for assigning economic value to investments in reliability and resilience. VBRP can play an important role in addressing the new challenges faced by electric utility planners and help utilities balance reliability, affordability, safety, and environmental sustainability moving in the future.

2.2 Value-Based Reliability Planning

Economic efficiency is the underpinning of value-based reliability planning. The goal is to identify economically efficient strategies for which the cost of improving reliability is less than or equal to the benefit to customers from the improvement. Utilities could end up spending too much or too little on reliability if they do not know its value to customers. The cost (and price) of electricity will increase unnecessarily if utilities over-invest in reliability and provide higher levels than customers value. Conversely, customers will experience unnecessary interruption costs and inconvenience that they could have avoided if utilities under-invest in reliability. In the past, customers had

> ***Value-based reliability planning***:
>
> matching the level of reliability investments with the economic benefit from the reliability improvement.

little choice other than to bear these unnecessary costs. Today, utilities risk losing customers altogether if they do not balance these costs correctly, as customers have more options for purchasing electricity (microgrids[4], self-generation, community choice aggregation[5], etc.).

Standard Reliability Metrics

SAIDI (System Average Interruption Duration Index)	**SAIFI** (System Average Interruption Frequency Index)	**CAIDI** (Customer Average Interruption Duration Index)
Total annual duration of interruptions for a typical customer	Average number of interruptions per year for a typical customer	Average length of time that a typical customer's outage lasts (or, average restoration time)
$SAIDI = \frac{\sum U_i N_i}{N_T}$	$SAIFI = \frac{\sum \lambda_i N_i}{N_T}$	$CAIDI = \frac{\sum U_i N_i}{\sum \lambda_i N_i}$

Where:

- U_i is the annual outage time for location *i*
- N_i is the number of customers
- N_T is the total number of customers served
- λ_i is the failure rate for location *i*

"Value of service" (VOS) is the economic value that customers place on reliability. At the utility service territory-level, VOS is expressed in a variety of ways, such as $/unserved kWh or $/customer-minute interrupted. SAIDI and SAIFI are reliability indices that represent average outage duration and frequency for a utility's customer base (see callout box above for definitions). One may also express VOS in terms of these indices, such as calculating $/SAIDI minute or $/SAIFI. These types of VOS measures are averages or sums cumulated over all of a utility's customers. Underlying these aggregate values are the VOS quantities for each customer. The value that customers place on service varies considerably among customers, as certain customers have higher VOS than others. For example, a residential customer may not incur significant costs or be inconvenienced by frequent, shorter duration interruptions. On the other hand, a large, industrial customer may incur substantial costs from loss of production from frequent, momentary outages. Even within the same customer class, VOS varies among customers. A stay-at-home parent may have a very different VOS than a day trader operating out of her home. These examples are all located on a particular circuit within a utility's service territory—and there is a wide variation in VOS across circuits. Utilities thus have significant opportunities to optimize investments by targeting high-value circuits, or circuits with high costs of unreliability.

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4 For more information on microgrids, see: https://building-microgrid.lbl.gov/about-microgrids

5 For more information on community choice aggregation, see: http://www.cpuc.ca.gov/general.aspx?id=2567

The objective in value-based planning is to minimize the total costs of power by balancing the cost of investments in reliability against the costs that customers experience as a result of unreliability associated with the investment. Figure 2-1 shows this concept graphically. Reliability is on the x-axis and cost is on the y-axis. The blue line shows utility costs and the diminishing marginal returns on reliability investments. Toward the left, the slope is small, reflecting larger increases in reliability for each unit of cost. As reliability increases, the slope of the line does as well, as each additional unit of reliability costs more at the margin. The red line shows interruption costs for each level of reliability. The change in slope reflects the decreasing marginal cost of interruptions as reliability increases; if reliability is high, marginal interruption costs are lower. The negative value of this marginal cost (i.e., MC x -1) is the marginal benefit of decreasing interruptions. The green line shows total cost, or investment cost plus outage cost. Total cost will be at a minimum at R*, where the marginal cost of investing in reliability (slope of the blue line) equals the marginal benefit of reducing interruptions (negative slope of the red line). To the left of this point, each $1 invested in reliability decreases interruption costs by more than $1, so making the investment has a net benefit. To the right of this point, interruption costs decrease by less than $1 and increasing reliability adds unnecessary cost to the system.

To find point R*, planners need to know utility costs <u>and</u> customer interruption costs. Utility costs are the sum of investment, operating, and maintenance costs, which are relatively straightforward to calculate using standard engineering cost estimation procedures. Customer interruption costs are the missing piece of the equation and researchers use the results from CIC surveys to estimate them. Note that this guidebook only covers customer interruptions costs and not incremental costs incurred during an outage by utilities or by society in general.

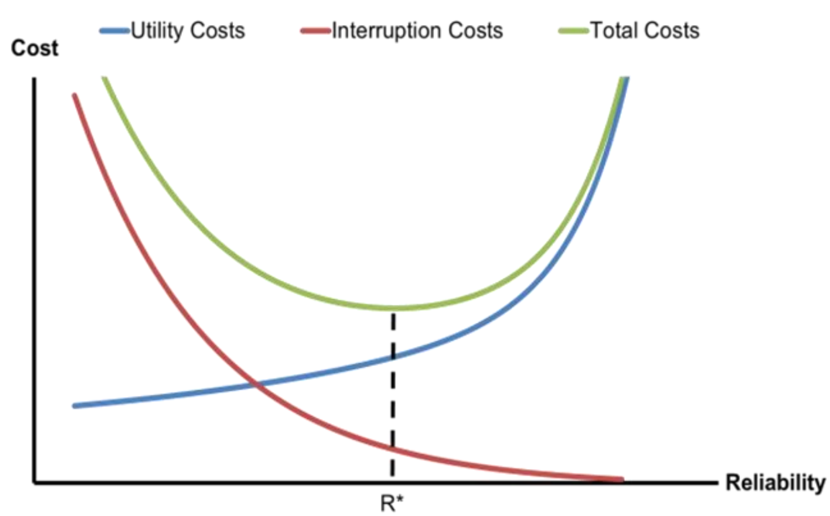

Figure 2-1. Components of the Total Cost of Unreliability

2.2.1 Case Studies

The following examples illustrate real-world cases where utilities used value-based planning to inform a future investment decision. Planners considering conducting a CIC survey may find these case studies useful. More details for each case are located in Appendix A.

2.2.1.1 Generation Planning

Value-based planning is relevant for large, vertically-integrated utilities and wholesale market designers as they consider long-term generation needs.[6] In both cases, planners can use VOS to determine the optimal planning reserve margin, or the optimal amount of generation capacity that should be available in excess of the average system peak demand level. Vertically-integrated utilities have used VOS to decide whether to procure additional generation resources. Regulators can use VOS to set resource adequacy (RA) requirements.

Regulators typically expect utilities to meet certain RA requirements by maintaining adequate planning reserve margins. Historically, generation planners have set planning reserve margins by following arbitrarily chosen industry standards related to the probability of lost load (e.g., one day in ten years). The problem with such arbitrary planning standards is that they do not take account of the costs that customers experience as a result of potential power interruption (Carden, et al., 2011). The economic cost of generation shortfalls—including more expected brownouts—could be small or large compared to the cost of building and maintaining excess generation capacity, but these tradeoffs are typically not quantified.

Newell et al. (2014) conducted a study for the Public Utility Commission of Texas (PUCT) to estimate the economically optimal reserve margin for ERCOT's[7] wholesale market. The traditional 1-in-10 (0.1 LOLE)[8] standard translated to a 14.1% reserve margin for ERCOT. The study used value of lost load (VOLL)—in units of $/MWh—as an input to the study to estimate the cost of power interruptions to customers. The study found that the optimal reserve margin was 10.2%, which was less than the 14.1% needed to meet the traditional LOLE standard. The authors conducted a sensitivity analysis—with VOLL ranging from $4,500 - $18,000/MWh—to account for uncertainty in the input parameters. The optimal reserve margin ranged from 8.9% to 11.8%, which was still below the traditional reserve margin. The VOLL estimate reflected the High System-Wide Offer cap of $9,000/MWh. Researchers could also estimate this input using a CIC study to obtain a VOLL that reflects interruption costs for the study area. Regardless of method, the key takeaway is that incorporating a VOLL estimate in generation studies can find reserve margins with lower total system costs than those based on traditional LOLE standards.

2.2.1.2 Transmission & Distribution Planning

A number of utilities are using value-based planning when evaluating investments in T&D, especially as they roll out grid modernization plans that include investments in distribution automation. A recent

[6] See (Keane & Woo, 1992) for an early example of using CIC to plan generation reliability.
[7] Electricity Reliability Council of Texas
[8] The traditional RA reliability standard is 1 day of firm load shed in 10 years.

example is Avangrid's Distributed System Implementation Plan (DSIP) (Avangrid, 2016). In 2016, the New York State Public Service Commission (NY PSC) directed investor-owned utilities in New York to compile and make available to stakeholders a benefit-cost analysis (BCA) handbook. The handbooks were to describe and quantify benefit and cost components and their application in evaluating DER projects. Avangrid's BCA handbook specifies that benefits should include net avoided outage costs. The handbook also states that these costs should be customer class-specific—even customer-specific, if possible—and that the estimates should be based on customers' willingness-to-pay for reliability.

> ***Outage Management System (OMS)***
>
> A system that utilities use to track outages, collect data, provide operational information and schedule crews for outage repair.

Avangrid[9] applied this methodology to its DSIP—specifically, the business case for implementing an advanced metering infrastructure (AMI). If implemented, Avangrid would be able to integrate the AMI with an outage management system (OMS) to reduce the duration of certain outages. Among other functions, an OMS tracks outages, provides operational information, schedules planned outage work, and dispatches repair crews. A third-party assessment found that AMI-OMS integration would reduce customer outage duration in cases where the outage was reported by a "last gasp" signal from the meters—as opposed to telemetry (or waiting for the customers to call and report it). AMI-OMS integration decreased outage durations due to both the time to confirm the outage (3 minutes faster than a call) and to pinpoint the location (12 minutes faster than a crew). A CIC study examined Avangrid's historical outages and customer level data to estimate the customer value associated with the reductions in customer outage minutes. Each historical outage had a value that represented the actual economic cost—as well as a lower value representing what the outage cost would have been with the reduced outage durations from the proposed AMI-OMS integration. The difference between the aggregate cost with the reduced duration and the actual aggregate cost was the benefit attributed to AMI-OMS integration. The BCA found that outage cost reduction benefits were $74 million out of $711 million in total AMI benefits over 20 years, which exceeded cost estimates of $578 million for AMI implementation.

Planners can also apply value-based planning methods to traditional distribution investment decisions. Larsen (2016) demonstrated a framework for quantifying benefits and costs of underground transmission and distribution lines, which incorporated avoided customer interruption costs as part of the analysis.[10] He developed a model for regulated utilities in Texas that related the number of interruptions to a set of variables including "abnormal weather." Larsen (2016) estimated benefits—in terms of reduced weather-related interruptions—from undergrounding existing and future T&D lines. The net benefits from fewer interruptions—over a forty year span—were estimated at $5.8 billion (NPV).

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[9] Specifically, its subsidiaries Rochester Gas & Electric (RG&E) and New York State Electric and Gas Corporation (NYSEG)

[10] This case study is not detailed in the appendix. For more details, see the journal article (Larsen, 2016).

A Puget Sound Energy (PSE) project is an example of value-based planning for transmission investments. PSE was considering a transmission upgrade to a portion of its service territory in 2015. Internal planning studies indicated that certain contingency scenarios might result in a significant number of interruptions if the transmission system was not upgraded within a few years. PSE used value-based planning to assess the economic impacts of taking no action to upgrade the system. They commissioned a study to simulate customer outages for the worst case scenarios of equipment failure and estimate the customer outage costs resulting from each scenario. The study estimated the number of customers impacted by the outages and the total interruption cost for each scenario. They found that the total outage cost for the 2018 scenario was $92 million and for the 2024 scenario was $277 million. This study helped PSE assess the benefits (i.e., avoided interruption costs) for a proposed transmission upgrade.

2.2.1.3 Operations Planning

Industry and academic literature has numerous examples of applying value-based planning to generation, distribution, and transmission investment decisions. Applications to operations and business processes thus far have been limited. The previous section described using AMI-OMS integration to reduce the duration of customer outages. Schellenberg et al. (2016) proposed that utilities incorporate customer interruption costs into outage management systems to prioritize outage restorations. The OMS and associated business processes can currently prioritize outage repairs based on safety considerations, number of customers without power, and amount of unserved kWh, along with other factors. Given the variation in outage costs between customers, incorporating CIC estimates into the prioritization process would allow work to be scheduled and crews dispatched—for both routine maintenance and unplanned/repair outages—in a way that maximized customer value. For example, if two circuits experienced unplanned power outages and had equal levels of unserved kWh, there may be no way to prioritize one over the other. However, if CICs were part of the OMS, it could be possible to see that—due to a difference in customer class distribution and associated outage costs—one circuit may be experiencing much higher interruption costs. This information could be specific to the season, day of week, time of day, and expected duration of the outage. The utility could thus maximize overall customer value by prioritizing one circuit over the other for earlier repair.

2.3 ICE Calculator Overview

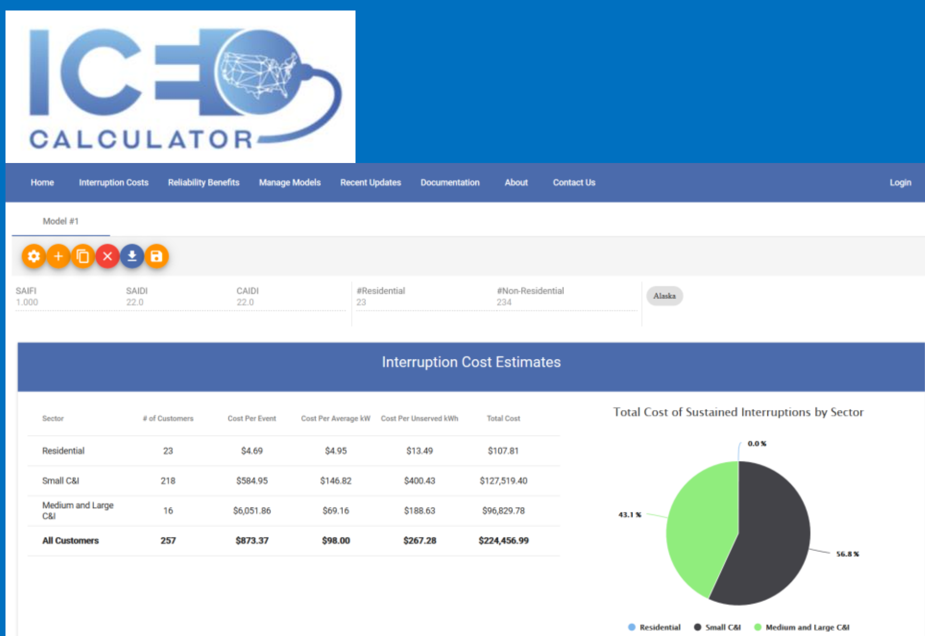
Utilities have been conducting CIC studies for decades. The Department of Energy, LBNL, and Nexant[11] have been working together for over ten years to help utilities determine customer interruption costs for planning purposes. Part of this effort has focused on analyzing data from existing CIC studies and organizing the results into a usable format for utilities and other stakeholders seeking to develop outage cost estimates. In 2003, Lawton et al. (2003) conducted a meta-analysis of CIC studies, assembling and standardizing the data from 24 surveys into a national database.

[11] Formerly Freeman, Sullivan & Co.

In 2009, Freeman, Sullivan & Co. (now Nexant) completed a meta-analysis of CIC studies that provided VOS estimates for customers in the U.S. (see Sullivan et al., (2009)). This analysis drew from 28 VOS studies conducted by 10 major U.S. utilities between 1989 and 2005. As interruption cost estimation methods used in the studies were nearly identical, it was possible to integrate the data into a meta-database. The meta-database became the basis for the ICE[12] Calculator, which was first released to the public in 2011. Nexant updated the meta-analysis in 2015 with data from several more studies and made subsequent improvements to the ICE Calculator. It now contains CIC data from 34 studies (total of 105,000 customer surveys) completed by 10 utilities between 1989 and 2012.

ICE Calculator (https://icecalculator.com)

The ICE Calculator is an interactive tool for estimating customer interruption costs for a customized service territory using data from 34 previous CIC studies. Users enter the expected reliability improvements (expressed in SAIDI, SAIFI and/or CAIDI), the timeframe, the distribution of outage onset times, and the customer characteristics of the service territory. The output is the benefit—in dollars—from the avoided interruption costs.



The ICE Calculator is an interactive tool for estimating interruption costs using the data from these aforementioned studies. Users of the tool enter a number of parameters, including the number of customers of each type and the geographic location. They enter the reliability changes in terms of SAIFI, SAIDI, and CAIDI and include the timeframe over which the changes will occur. Next, the ICE Calculator estimates four key outage cost metrics. Using the online calculator in this manner produces—at no charge to the user—approximate CIC estimates for utilities. It is also possible to produce more accurate estimates using a more customized approach. Researchers can use the meta-data underpinning the calculator to develop econometric models specific to a particular utility. Although a survey is the gold

12 Interruption Cost Estimation

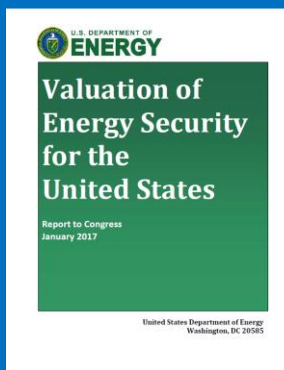
standard for estimating outage costs, the ICE Calculator and the meta-database provide alternatives if the utility does not have the time or resources to conduct a formal survey.

While the ICE Calculator is a useful tool, it does have some limitations. The Northeast U.S. is not well represented in the underlying meta-database and the surveys were conducted sporadically over a 20-year period. These aspects of the data make it difficult to disentangle temporal and geographical effects on outage costs. Using the ICE Calculator online tool does not allow for a more granular customer-by-customer approach and instead uses average values across customer classes. The benefits of using the customer-specific CIC study are greater when the utility suspects that its customers may have interruption costs that are different than the regions represented by the ICE Calculator. The benefits of a study are also greater when a utility suspects it may have significant variation in interruption costs between certain customer types or geographical areas within its service that it needs to understand and disintermediate for investment planning purposes.

3. Review of Methods

Customer interruption cost studies have used a variety of methods to determine costs, including customer survey-based methods, market-based methods, regional economic modeling, and blackout case studies. This section reviews these four main methods.

CIC Estimation Methods


U.S. DEPARTMENT OF ENERGY

Valuation of Energy Security for the United States

Report to Congress
January 2017

United States Department of Energy
Washington, DC 20585

For a recent, thorough review of the literature on CIC estimation methods, see the U. S. Department of Energy report: "Valuation of Energy Security for the United States" (Chapter 4).

Value based reliability planning focuses on the impact of short duration outages. The twenty-four hour mark is the approximate point at which the literature makes the distinction between short-duration and long-duration outages (Sullivan & Schellenberg, 2013) (Sullivan, et al., 2015).[13] During short duration outages, customers incur "direct costs," which they bear directly from the interruption of power to their homes or facilities.

During long duration outages, customers incur indirect costs in addition to direct costs and it becomes necessary to include these indirect costs to fully account for all customer interruption costs. Indirect costs occur when businesses and households experience economic losses from other companies, organizations, and institutions not having power. They are due to connections between firms and sectors and the resulting economic production disruptions that propagate across firms and industries via market interactions. Connections can occur between firms in the relative prices of goods and the quantities of inputs bought or outputs sold. They also occur between individuals and firms in the form of lost wages and reduced consumer spending. Interruption costs associated with public institutions are also considered indirect costs, as individuals and firms incur costs from the absence of public services such as water treatment and emergency services. Indirect costs are thus not limited to the customers within a utility service area and can propagate to a wider geographical area (Sullivan & Schellenberg, 2013).

Table 3-1 shows the strengths and weaknesses of each of the four methods mentioned above and discussed in more detail in this section. Researchers generally prefer survey-based methods for CIC studies when conducting the studies for the purposes of utility planning. This is due to their historical precedent, accuracy, and versatility. The other methods are more appropriate for other types of studies: market-based methods measure observed behavior, regional economic models estimate

[13] Experts do not universally agree that twenty-four hours is the appropriate threshold, nor is there significant empirical evidence that measures the timing of the onset of indirect costs as the outage duration increases (Workshop Proceedings, 2018).

impacts from long duration outages, and blackout studies assess impacts from actual widespread blackouts. This Guidebook details a survey-based approach in Section 4.

Survey-based methods have been used successfully in dozens of past studies. Utility customers have generally experienced short duration outages in the past and can estimate the economic impacts and/or inconvenience based on this past experience.[14] They are also applicable to different geographical areas and interruption scenarios, which makes them useful to utility planners. Survey-based methods do have some weaknesses. They more expensive than other methods and are not as effective for measuring indirect costs—particularly for non-residential customers—as the economic interactions are too complex for either designing an appropriate survey or having respondents answer.

Market-based methods and regional economic modeling tend to be less costly than surveys, but suffer from other setbacks in measuring CICs from short duration outages. Market-based methods use data from actual observed behavior—as opposed to surveys or models—but the results are not applicable to the full range of possible outage scenarios. Regional economic models are useful for estimating economy-wide impacts from long duration outages, but lack the level of granularity that utility planners require, as well as empirical data on firm behavior. Blackout studies are based on actual interruptions and can estimate long duration outage CICs, but are relatively costly. In addition, major blackouts are not representative of most interruptions.

Table 3-1. Strengths and Weaknesses of CIC Estimation Methods

Method	Strengths	Weaknesses
Survey-based	▪ More accurate ▪ Applicable to many geographical areas and interruption scenarios	▪ Costly ▪ Responses are based on hypothetical scenarios ▪ Unable to estimate costs for long duration, widespread interruptions
Market-based	▪ Less costly than surveys ▪ Based on observed behavior	▪ Lack of available data to estimate full range of CICs
Regional Economic Modeling	▪ Inexpensive ▪ Can model indirect costs and adaptive behavior for long duration, widespread interruptions	▪ Lack of granularity ▪ Lack of data on firms' adaptive behavior during long duration outages ▪ Further model development required

[14] Sullivan and Schellenberg (2013) used a survey to estimate direct costs from a long duration outage and applied a scaling factor to estimate indirect costs from the direct costs.

Blackout Study	▪ Responses are based on actual interruptions ▪ Can estimate costs for long duration, widespread interruptions	▪ Costly ▪ Major blackouts not representative

3.1.1 Survey-based methods

Customer surveys are the most widely-used approach for estimating customer outage costs (Sullivan, et al., 2012). In this approach, researchers ask representative samples of customers to estimate the costs they would experience given a number of hypothetical outage scenarios. The researchers systematically vary key characteristics of the outages described in these scenarios in order to measure differential effects of outage events with different sets of characteristics. These characteristics include interruption duration, season, day of week, time of day, cause of the outage, and whether the utility gave advance warning, among others. Survey based methods are significantly more expensive than the other methods for estimating customer outage costs, but they offer several advantages over other measurement protocols. Chief among these advantages is that survey-based methods can estimate outage costs for a wide variety of reliability conditions not observable using the other techniques. For example, they can provide outage costs by time of day, day of week, and for outages of varying duration and occurring during different seasons. They can provide results that researchers can statistically generalize to the customer populations of interest for planning. Additionally, researchers can use them to target customers who may have more critical requirements for reliability.

Several types of survey-based valuation methods are available for CIC study teams to use. The preferred method depends on which customer class will be the subject of the survey. Outage costs for non-residential customers (i.e., commercial and industrial customers) are typically attributed to tangible, objectively measurable losses to economic productivity. For these customers, direct cost measurement is the best valuation method (Sullivan & Keane, 1995). Outage costs for residential customers consist of both tangible economic losses (e.g. damage to household equipment, food spoilage and lost opportunity to use household appliances to meet needs) and intangible economic losses (e.g. inconvenience). Accordingly, CIC study teams often use stated preference contingent valuation techniques to ascertain information for both direct economic losses and inconvenience.

3.1.1.1 Direct Cost Method

Researchers determine the direct economic cost of outages to commercial and industrial customers (i) by asking about specific costs incurred and savings realized related to a set of hypothetical power interruption scenarios (s)—then summing them over all n customers to find the total direct cost under each scenario (s). Equation 3-1 depicts this relationship.

Equation 3-1. Direct Cost of Interruptions for Non-Residential Customers

$$\textbf{Direct Cost}_{\mathbf{s}} = \sum_{\mathbf{i=1}}^{\mathbf{n}} (\mathbf{VLP_{is}} + \mathbf{IRC_{is}} - \mathbf{IRS_{is}})$$

where:

- VLP is the value of lost production
- IRC is the set of interruption-related costs
- IRS is the set of interruption-related savings.

The following bullets discuss each component of the direct cost equation separately, focusing on information typically collected from businesses.

Value of lost production (VLP)

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 is able to generate given that the outage occurred. In short, VLP is a business' net loss in the economic value of production after accounting for its ability to make up for lost production. VLP includes the entire cost of making or selling the product as well as any profit it could have made from the production.

Interruption-related costs (IRC)

Interruption-related costs are additional production costs directly incurred because of the interruption. Interruption-related costs typically include:

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

Interruption-related savings (IRS)

Interruption-related savings are production cost savings resulting from the interruption. Businesses see savings from unused inputs when production or sales cannot occur. For example, if a soft drink bottling company experienced an outage, the company may use less water during the outage and thus save money on its water 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 study teams must measure them and subtract them from the other cost components to ensure they do not double count outage costs. Savings include:

- Unpaid wages during the outage (if any)
- Cost of raw materials not used because of the outage
- Cost of fuel not used; and
- Scrap value of any damaged materials

Interruption cost calculations only include incremental losses resulting from unreliability, which are costs beyond the normal costs of production. If the customer is able to make up some percentage of its production loss at a later date (e.g., by running the production facility during times when it would normally be idle), the CIC estimate does not include the full value of the production loss. Rather, it is 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.

3.1.1.2 Stated Preference Methods

Researchers can use revealed preference data—or the amount that consumers <u>actually</u> pay for a good—to determine a good's economic value to consumers when a market exists for the good. Researchers can use stated preference methods to determine the value of a good when a market for the good does not exist—such as a market for perfectly reliable power. Consumers indicate what they <u>would</u> pay for a good in a hypothetical market in stated preference surveys. As indicated earlier, a significant fraction of the interruption costs borne by residential customers comes from the inconvenience of the power going out. As no market exists for eliminating the inconvenience of an outage, researchers use stated preference methods to determine what customers would be hypothetically willing to pay if it were possible to give them the option.

A common method for eliciting customer interruption costs through stated preferences is called willingness to pay (WTP). The WTP approach to CIC estimation does not provide a measurement of the direct value of the interruption in terms of net lost productivity, but rather how much the customer would be willing to pay to avoid it. This technique employs the concept of compensating valuation. In the parlance of welfare economics, customers estimate the economic value that would leave their welfare unchanged compared to a situation in which no power interruption occurred. WTP is especially useful when intangible costs are present, which by their nature are difficult to estimate using the direct cost measurement approach.

The WTP measurement technique covered in this Guidebook has two stages. In the first stage, the CIC survey instrument asks customers to consider how the outage would affect their household and to estimate their out-of-pocket and inconvenience costs. In the second stage, the survey uses the payment card technique to ask respondents to indicate how much they would be willing to pay to avoid the outage. It is the measurement from the second stage—the WTP measurement—that utilities typically use for planning. The payment card technique presents a number of WTP amounts (in dollars) and asks the respondent to select one from the list or to write in an alternative amount. Other WTP elicitation techniques include the open-ended “direct question,” where the survey simply asks how much the respondent is willing to pay but does not provide a range of possible responses. This technique for stated preference surveys was found to yield relatively low response rates and no longer receives widespread use (Carson & Czajkowski, 2014).

Willingness-to-accept (WTA) is another stated preference method which is available, but not commonly used, for CIC studies. With WTA, the study team asks customers how much they would be willing to accept in payment as compensation for experiencing the hypothetical power outage. WTA estimates tend to be higher than those for WTP and have been used as an upper bound in some studies (Sullivan & Keane, 1995) (Horowitz & McConnell, 2002).

Discrete choice experiments (DCE) are another way to elicit preference information in a CV study. These techniques are popular in the general literature on non-market valuation, but are less common in the CIC literature (DOE, 2017b), (Carson & Czajkowski, 2014). DCE techniques present choice sets consisting of different options to respondents and ask them to select their preferred option, which includes the status quo. Binary (or dichotomous) choice experiments present only two options, where the survey would present a non-status quo option and ask respondents whether they would be willing to pay a certain amount for it. DCE choice sets can also consist of multiple options, which for interruption cost studies could contain reliability scenarios with variations in interruption frequency, duration, onset time, cost to avoid, etc. Researchers can obtain more preference information with more options in the choice set, but must balance this against the ability of respondents to process each option and accurately respond. DCE Examples of CIC studies include Ozbafli & Jenkins (2016), Pepermans (2011), Carlsson and Martinsson (2008), and Beenstock et al. (1998).

Stated preference methods do have certain weaknesses for determining interruption costs. One weakness is that consumers are not actually making economic choices in WTP experiments. Customers do not have to take delivery of the offered service or pay for it. This may cause some respondents to overstate or understate their true WTP and thus introduce what is known as “hypothetical bias” into the measurements—though it is unknown how much it affects measurements in CIC surveys. Another issue is strategic response, which is when customers may deliberately overstate or understate interruption costs to influence utility investment in reliability improvement projects (Beenstock, et al., 1997). Overstating WTP is more of a concern with non-residential customers and thus using the method only for residential customers can mitigate the issue. Proper survey design can mitigate understated WTP by asking follow-up questions if a respondent answers that the household’s WTP is $0. Stated preference studies can sometimes suffer from anchoring bias, which is when the structure of the survey influences the answers given by respondents. For example, without a strong preference for an actual willingness-to-pay amount, the respondent in a payment card study may anchor her response near the highest, lowest, or middle value of the range, regardless of what the range is. In these circumstances, respondents may answer differently if presented with alternative ranges of payment options.

The different elicitation techniques for stated preference surveys have their own strengths and weaknesses for application to a utility-sponsored CIC study. If budget were not a factor or a very large random sample of residential customers could be recruited at little cost, researchers could follow the recommendations of an expert panel convened by the U.S. federal government in 1993 to assess CV[15] and ask each respondent a single binary discrete choice WTP question with a randomly assigned cost. In practice, researchers must make tradeoffs between budget and methods. The payment card technique has been used more extensively in past studies, as researchers can obtain more information from a single payment card question than they can from a DCE question. (Each payment card question settles on a specific WTP dollar amount, while each DCE question yields information about a tradeoff that must be combined with the rest of survey responses and analyzed to reach a valuation.) This allows utilities to avoid having to fund recruitment of very large samples—or ask so many questions on the survey that bias is introduced from survey fatigue (i.e., customers either do not complete the survey or rush through the questions).

There is no consensus among experts that the WTP payment card technique is the best method for eliciting interruption costs (Shawhan, 2018) (Larsen, et al., 2018). However, the payment card technique has been used in dozens of CIC studies (for residential customers) and provides the basis for the ICE Calculator meta-database. The study design, survey instrument, and analytical methods associated with the technique have been refined over the years to minimize bias while operating within utility budget and time constraints. For these reasons, this Guidebook details the payment card method for eliciting residential interruption costs. However, there is the potential to both further refine the payment card technique and explore the use of DCE for utility-sponsored studies. Section 6, "Frontiers for Further Research," covers this issue further and includes a number of potential improvements from leading stated preference and interruption cost researchers.

3.1.2 Market-based Methods

Transactions occur in the market for electricity services that can reveal the actual economic worth of reliability to customers. All else being equal, researchers prefer to measure the value of goods and services based on these types of revealed preferences (as opposed to stated preferences). This preference has led to efforts to measure customer interruption costs using market-based methods[16]. Consumers have a number of options in the energy marketplace for trading off reliability with cost. For example, some consumers can choose non-firm, interruptible rates, reflecting a tradeoff of reliability

[15] A panel of experts developed these guidelines after the groundbreaking use of the method to estimate the cost of the Exxon Valdez oil spill in 1989. See (Arrow, et al., 1993).
[16] See Matsukawa & Fujii (1994) and Beenstock, et al. (1997) for examples of market-based studies.

for price. Other consumers purchase equipment to improve reliability (i.e., backup generators and battery storage).

Efforts to use information about these decisions to estimate the economic value of service reliability have not always been successful. The key drawback to this approach is the lack of data available to cover the full range of outage conditions (e.g., duration and outage type), customers (e.g., residential, commercial, and industrial) and prices necessary to construct robust customer damage functions. In short, accurate and comprehensive market data is simply not available to estimate the wide range of customer interruption costs needed for utilities to make robust planning decisions.

3.1.3 Regional Economic Modeling

Researchers have developed regional economic models to estimate interruption costs at larger scales and over longer durations. This category of models contains several different types, including input/output (I/O) models, computable general equilibrium (CGE) models, and macro-economic models. (See Sanstad (2016) for a thorough description of the model types.) Regional economic models estimate both direct and indirect costs. Indirect costs to customers are important for estimating the costs of interruptions lasting longer than a day or for wider geographic areas. Each firm uses inputs and produces outputs, with the outputs for some firms becoming the inputs for others. Indirect costs result from a firm losing inputs due to upstream disruptions from the interruption. Regional economic models account for these connections between firms and sectors and account for economic production disruptions that propagate across firms and industries via market interactions.

Regional economic models are able to capture indirect costs and many are also able to represent adaptive behavior by firms to mitigate economic losses during power outages. This adaptive behavior can reduce indirect costs. The ability to capture these dynamics is an advantage of regional economic models over survey-based methods and may make them better suited to estimate costs for long duration, widespread outages. A key drawback of these models is that although researchers know that firms will adapt to long duration outages, they do not know *how* they will adapt or how to monetize the impact of these decisions. Sanstad (2016) notes that there are very few publicly-available examples of firms behaving under these conditions with which to give the models an empirical grounding. Nonetheless, regional economic models are useful complements to survey-based methods, and with continued development, will yield valuable insights into the costs of long duration, widespread interruptions.

3.1.4 Blackout Studies

Blackout studies are case studies of specific (usually widespread and lengthy) outages that have occurred in the past and where the associated economic cost has been estimated. Examples of these types of studies include the New York City blackout of 1977 (Corwin & Miles, 1978), the Northridge Earthquake Outage of 1994 (Gordon, et al., 1998), the California rolling blackouts of 2001 (AUS Consultants, 2001) and the 2003 Northeast Blackout (Anderson & Geckil, 2003). Blackout studies are costly to conduct, as they generally involve surveying customers who experienced the outage to determine how the customers responded and developing a model for economic impacts. These studies are useful for estimating costs of large-scale outages and potentially extrapolating to what a similar outage might cost in the future. Blackout studies are particularly useful for understanding vulnerabilities to dramatic losses of electricity supply and the types of preparations—unrelated to the electrical grid—that a region would need to undertake to improve resilience to such events. However, blackout studies are less useful when estimating costs of shorter, smaller-scale outages that are often the basis for value-based planning exercises. One complication when studying large scale blackouts is that they often occur during natural disasters (e.g., hurricanes) and it can be difficult to separate the costs of the outage from the other costs associated with the disaster. It should also be noted that investigating the costs associated with a blackout can be cost-prohibitive.

4. Conducting a Customer Interruption Cost Study

The remainder of this Guidebook focuses on the methods and procedures for conducting a survey-based CIC study. As Figure 4-1 shows, an outage cost study has five basic steps—from initial research design to analysis and reporting. The first step in the process is to establish the scope of the study. This step includes carefully specifying the purpose for conducting the study, how the utility (or other implementer) will use the results, the customers to include, the interruption scenarios, the intended audience, and the study timeframe. The next step is to establish the sampling strategy by determining the number (and types) of customers to include and the sampling procedure. Third, the study team develops the survey instrument—an important step that involves designing questions that will collect information from the survey respondents. Fourth, the team (or a market research firm) administers the survey. The fifth step is to clean and analyze the data and report results.

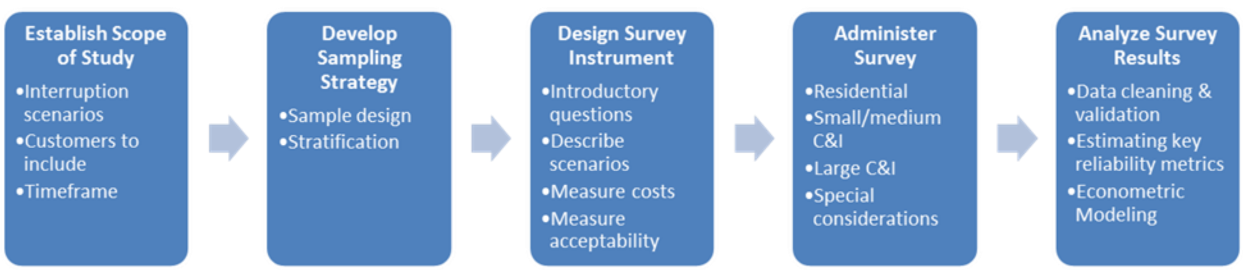


Figure 4-1. Steps for Conducting a CIC Study

4.1 Step 1: Establish Scope of Study

Summary: Determine the types of outages the study should examine (e.g. T&D vs. generation), the range of outage durations to cover, which types of customers to include, specific customer segments to differentiate, and the timeframe for completing the study.

Recommendations:

- Use the underlying purpose for conducting the study to inform critical design decisions. When designing the study, pay careful consideration to how the utility will use the CIC results and any applicable regulatory guidance.
- Determine whether it makes sense to hire a third party to assist with certain or all components of the study.

Establishing the CIC study scope is a critical first step for the study team, as it sets the stage for the rest of the work. The underlying question that drives the scope is "what is the purpose for conducting the study?" As illustrated in the case studies in Section 2.2.1, utilities can use interruption costs in a wide variety of planning and regulatory settings. Sometimes, utilities carry out these studies voluntarily to support planning applications internal to the utility. CIC studies can support generation planning, T&D planning and operational changes related to outage management. In other cases, results from CIC studies support resource adequacy proceedings by rationalizing proposed improvements in reliability and resilience to regulators and other stakeholders.

! In this phase, the study team makes a number of critical decisions based on the purpose of the study and how the results will be used. These design decisions include:

- The specific outage scenarios to include in the study (e.g., routine T&D outages without notice, rotating outages with notice caused by generation shortfalls, unexpected outages caused by storms or accidents impacting the T&D system, power quality problems). This also includes the range of outage durations to cover (momentary, 30 minutes, 1 hour, 4 hours, 8 hours, 16 hours, etc.)
- Which customers/customer classes to include in the study (e.g., commercial, residential, industrial) and whether to estimate costs for specific customer subgroups (e.g., customer type, size, business type, or geographical location)
- The timeframe and project schedule for completing the study

4.1.1 Determine Outage Scenarios

Establishing the scenarios to include in the study is an important part of a study, because interruption costs vary significantly as a function of duration, season, onset time and extent of notice. These factors have different values based on the cause of the outage: generation shortfall, T&D equipment failure, etc. For example, a study to support

Outage Scenario

Hypothetical outage for which customers will estimate the economic costs they incur. The scenario defines the specific of the outage, such as onset time, cause (if known), season, duration, etc. The scenarios used in the CIC study should be representative of the utility's actual outages, as T&D and generation outages have different characteristics.

generation (and possibly transmission and distribution) planning must pose realistic generation-related outage cost scenarios to customers that vary by season and the amount of notice that customers receive. For a summer peaking utility, only two kinds of generation outages occur—those with the amount of notice specified by the utility's emergency operating plan and those without notice. As the timing and duration of the system peak is predictable by season, time of day and day of week, the study team does not need to vary these aspects of the outage scenarios to obtain a valid measurement of the interruption costs for this type of outage.

Interruption cost studies focusing on generation-related outages are generally not directly applicable to T&D planning. T&D outages usually occur without notice and their timing is much less predictable than that of generation outages (i.e., they can occur with some probability across all seasons, days and hours of the day). Virtually all customer interruption cost studies have shown that customer outage costs vary significantly by time of day. Outages occurring in the evening impose very different costs on residential and commercial customers than those which occur during the day. Likewise, outages occurring on weekends impose very different costs on most customers than those occurring on weekdays (Sullivan, et al., 2012).

The set of appropriate scenarios for the study determines a number of important aspects of survey design, including the number of scenarios to present to each customer and the number of survey versions necessary to accommodate the number of scenarios. As these decisions also impact survey cost, the study team should make them in consultation with those who are ultimately using the data, parties responsible for customer engagement, and the utility's market research experts.

4.1.2 Identify Customers/Customer Classes to be Included in the Study

CIC studies can estimate interruption costs for a single customer (e.g., a major manufacturing facility), for customer classes defined by ratemaking (e.g., residential, small C&I, large C&I), for customers located within a given geographic area served by the utility (e.g., downtown), or for specific business types (e.g., high-tech manufacturing facilities). The study team should take into account how the utility will use the CIC results and any applicable regulatory guidance for which types of customers the study should include. CIC studies usually include at least three groups of customers: residential, small/medium C&I, and large C&I. These groups have very different interruption costs and the way that the study team recruits and administers the survey to these groups varies considerably. In some cases, the needs of the study (or applicable regulatory guidelines) may require that the team include additional customer classes—such as agricultural—or break C&I into more than two size groupings. For a large T&D infrastructure project, the team may require CIC estimates from customers spanning different regions over long distances.

> ***Customer Class***
>
> A broad rate group consisting of a particular type of customer. Standard customer classes are residential, commercial and industrial with size differentiation in the non-residential classes. Utilities use customer class designations to allocate costs for rate design.

4.1.3 Establish the Timeframe and Project Schedule

Survey-based outage cost studies typically require at least six months to complete—from the initial design to publishing findings. It is extremely important to develop a realistic project schedule that allows for the study team to carry out the design work in consultation with various experts inside and outside the utility. Survey administration will require at least three months of intensive field effort. It is also critical to allow sampled customers sufficient time to respond to these relatively long and complex surveys in order to achieve an acceptable response rate, as discussed in more detail in Section 4.4.

!

Utilities will often contract with one or more third party market research firms to assist with the different steps in the study. Utilities can expect to pay between $750,000 and $1 million[17] for a third party to assist with all components of the study: scoping, sample design, survey instrument design, survey implementation, and analysis and reporting. A large portion of this cost is a fixed cost associated with sample and survey design. There is also a variable cost per unit complete. The variable cost depends on the survey response rate, which in turn depends on the quality of contact info, the relationship of business account reps to customers, and the coverage of the account reps. Utilities should make the decision to retain a market research firm based on budget, internal analytical and implementation capabilities, subject matter expertise, and available capacity for internal resources.

[17] This range comes from the authors' experience conducting CIC studies and judgement regarding costs for a typical study.

4.2 Step 2: Develop Sampling Strategy

Summary: Develop an effective sampling strategy which minimizes bias, maximizes precision of the interruption cost estimates, and stratifies customer classes based on a range of sensitivities to interruptions. At the same time, survey designers must consider the number of strata to ensure that the surveying process is not too complex for the study team to undertake.

Recommendations:

- Select subgroups within each customer class based on study objectives and/or if there is evidence of significant interruption cost variation.
- Stratify each customer class (or subgroup, if applicable) by the log of usage, which is a proxy for interruption costs.
- Determine the number of strata. Three to five strata strikes a reasonable balance between performance and complexity, in the absence of data from a previous study to guide the decision.
- Use the Dalenius-Hodges method to find the optimal strata boundaries.
- Use Neyman allocation to determine the sample size for each stratum.

In most cases, it is impossible—and not necessary due to sampling techniques that represent the population--to administer a CIC survey to all of the customers within a utility service territory. Accordingly, the study team must administer the survey to some portion (a sample) of the customer population. This process of sampling from the population of customers raises a number of important technical questions including:

- How should the study team select the customers who will receive the outage cost surveys?
- How many customers must complete the surveys for the study to be representative of the population?
- What considerations should the team make when deciding who to solicit?

This section describes the process of designing a sample to ensure that it can achieve the objectives of the study.

4.2.1 Sample Design

The first objective of a sample design is to ensure that customer outage costs estimated from the sample accurately represent the outage costs of the entire population. Results from a representative sample are said to be *unbiased estimates*—i.e., the mean of the sampled distribution of reported outage costs equals the true mean of the outage costs in the population. Random sampling—where each study subject has a predetermined, non-zero probability of being selected to take the survey—can effectively achieve this first objective assuming the study team has reasonably high response rates when administering the survey.

The second objective of proper sample design is to obtain the appropriate number of outage cost estimates to have an acceptable level of statistical precision (i.e., how many customers to sample).

Relating the sample result to the true value of the population will include some level of uncertainty due to the variance of outage cost estimates in the sample. That is, the outage cost estimates obtained from sampling will generally not be exactly equal to the true value of outage costs in the population. This difference occurs because of sample-to-sample variation within the customers included in the samples. For this reason, it is appropriate to think of interruption cost estimates obtained from sampling as values that exist within a range. The size of the range is a function of the confidence level, or how certain one can be that the true answer lies within the range. Statistical precision is defined as the percent deviation of the mean of the sample from the mean of the population. Precision is related to the size of the confidence interval around the outage cost estimate, so that the higher the precision, the narrower the confidence interval. If precision is too low, the range of possible outage cost values will be too broad to be useful for planning purposes. Precision is a function of two factors: the variation of the outage costs in the population and the size of the sample. Equation 4-1 shows the formula for precision *r*.

Equation 4-1. Formula for Precision

$$\boldsymbol{r = \frac{\sigma Z}{\mu \sqrt{n}}}$$

where:

- *r* is precision
- σ is the population standard deviation of the interruption costs
- μ is the population mean of the interruption costs
- *Z* is the standard normal variate (equal to 1.96 for a 95% confidence interval)
- *n* is the sample size.

Smaller values of *r* represent greater levels of precision, because this value represents the percent deviation of the sample mean from the true mean. For a given sample size, an estimate is made less precise as population variation (standard deviation σ) increases. The opposite is true for sample size: for a given population, estimates are made more precise as sample size increases. Study teams should approach the question of sample size and precision in one of two ways. First, teams could consider the project budget and then estimate the highest level of precision possible given the maximum sample sizes that the budget could accommodate. Alternatively, the team could start with the desired level of precision and then estimate the budget and sample size necessary for achieving it. In most cases, study teams determine sample sizes based on budgetary limitations due to the wide variation in interruption costs present within a population of customers.

Calculating precision (see Equation 4-1) involves knowing the mean and standard deviation of the population of interruption costs—yet these values are what we aim to estimate through sampling. In some cases, means and standard deviations from prior interruption cost studies have been used to estimate precision. In the absence of information from a prior study, the study team can use the mean and standard deviation of interruption costs from studies from other utilities. Table 4-1 through Table 4-3 show summary statistics for a one-hour outage from the 34 studies in the ICE Calculator meta-database. (Note that the customer class definitions have medium C&I grouped with large C&I and not small.)

Table 4-1. Summary Statistics for a 1-hour Outage from ICE Calculator Meta-Database: Residential ($2013)

Category	Outage Characteristic	Customers	Mean	Standard Deviation	Percentiles				
					p5	p25	p50	p75	p95
Season	Summer	8,888	$7	$14	$0	$0	$1	$7	$27
	Winter	763	$9	$14	$0	$0	$5	$10	$25
Weekday	Weekday	9,027	$7	$14	$0	$0	$2	$7	$27
	Weekend	624	$11	$21	$0	$1	$6	$14	$34
Region	Northwest	724	$3	$6	$0	$0	$0	$3	$17
	Southeast	5,587	$8	$12	$0	$0	$3	$10	$27
	West	3,340	$6	$18	$0	$0	$1	$6	$29
Time of Day	Morning, 7-11am	3,171	$8	$15	$0	$0	$3	$10	$33
	Afternoon, 12-4pm	5,501	$6	$12	$0	$0	$1	$6	$25
	Evening, 5-8pm	928	$8	$16	$0	$0	$4	$9	$28
	Late Evening/ Early Morning	51	$26	$51	$0	$1	$6	$20	$203

Table 4-2. Summary Statistics for a 1-hour Outage from ICE Calculator Meta-Database: Small C&I ($2013)

Category	Outage Characteristic	Customers	Mean	Standard Deviation	Percentiles				
					5 %	25%	50%	75%	95%
Season	Summer	10,052	$720	$2,358	$0	$0	$58	$482	$3,328
	Winter	1,135	$600	$1,951	$0	$0	$0	$325	$3,045
Weekday	Weekday	9,809	$742	$2,366	$0	$0	$58	$508	$3,476
	Weekend	1,378	$466	$1,947	$0	$0	$0	$200	$1,849
Region	Midwest	368	$776	$2,240	$0	$0	$117	$627	$3,133
	Northwest	2,354	$388	$1,480	$0	$0	$0	$266	$1,597
	Southeast	4,080	$787	$2,645	$0	$0	$0	$508	$3,685
	Southwest	1,343	$924	$2,748	$0	$0	$65	$651	$4,393
	West	3,042	$746	$2,162	$0	$0	$116	$579	$3,476

Table 4-3. Summary Statistics for a 1-hour Outage from ICE Calculator Meta-Database: Medium/Large C&I ($2013)

Category	Outage Characteristic	Customers	Mean	Standard Deviation	Percentiles				
					5%	25%	50%	75%	95%
Season	Summer	15,919	$16,374	$99,184	$0	$0	$666	$4,284	$51,106
	Winter	3,308	$10,606	$70,047	$0	$0	$203	$2,518	$31,085
Weekday	Weekday	17,685	$16,357	$98,262	$0	$0	$644	$4,373	$51,403
	Weekend	1,542	$4,190	$35,602	$0	$0	$139	$1,233	$11,105
Region	Midwest	1,474	$13,102	$78,670	$0	$0	$626	$4,164	$39,992
	Northwest	2,315	$3,777	$17,873	$0	$0	$198	$1,331	$15,435
	Southeast	9,063	$17,046	$99,064	$0	$0	$700	$4,483	$56,148
	Southwest	1,985	$6,318	$54,329	$0	$0	$146	$1,507	$15,515
	West	4,390	$22,928	$124,022	$0	$102	$1,015	$6,767	$79,365

Study teams can also use electricity usage as a proxy for interruption costs when estimating sample size and/or precision (Sullivan, et al., 2012). Like interruption costs, the distribution of usage within customer classes tends to be highly skewed towards the right. For example, Figure 4-2 shows consumption data for Pacific Gas & Electric (PG&E) customers from a 2012 CIC study—with the top 5th percentile of usage removed for display purposes (i.e., right tails are truncated). For each customer class, the majority of customers are concentrated in the lower end of the usage distribution with a long tail of high usage customers towards the upper end of the distribution—especially in the small/medium business (SMB), large business, and agricultural classes (Sullivan, et al., 2012).

Given the skewed nature of the data, it is difficult to achieve a high degree of precision, even with large sample sizes. Furthermore, increasing sample size to achieve greater precision has diminishing marginal value, because statistical precision increases with the square root of sample size n. Table 4-4 shows sample size targets by customer class for a typical CIC study. Sample sizes for each customer class will ultimately depend on the objectives of the study and the variation in the data for each utility, but the targets in Table 4-4 reflect overall sample sizes that study teams have used in the past for medium and large sized utilities. (Some smaller utilities may have a large C&I customer base less than 100 customers, in which case the target in the table would not apply.)

Stratified Sampling

Dividing a population into separate groups and sampling from each group, or "stratum." Stratification can allow researchers to obtain better precision without increasing sample size.

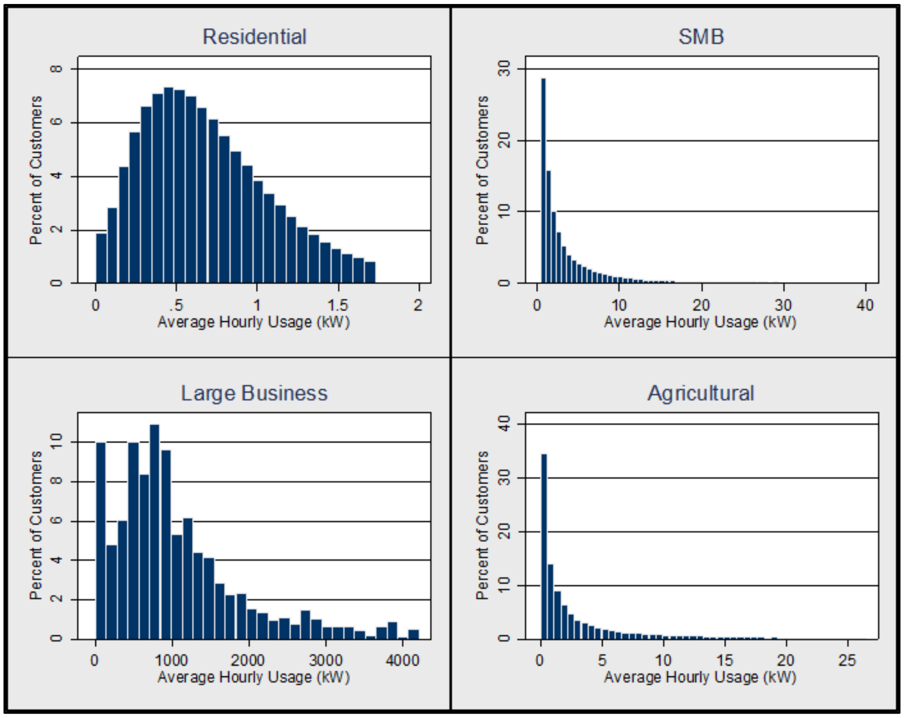


Figure 4-2. Distribution of Average Hourly Usage by Customer Class (Top 5th Percentile Removed)

Table 4-4. Typical Sample Size Targets by Customer Class

Customer Class	Sample Design Target
Residential	1,000 to 1,500
Small and Medium C&I	1,000 to 2,000
Large C&I	100 to 200

4.2.2 Stratification

Stratifying a sample is useful when significant variation is present within subgroups of the population. This is the case with interruption costs—which vary widely both between and within customer classes. Stratifying the sample serves two purposes. First, it improves the precision of the estimates. Second, it helps researchers obtain estimates for population parameters of interest which define the strata.

To stratify groups within the context of an outage cost survey, first identify subgroups within the population that might have significantly higher (or lower) outage costs relative to a typical customer. Second, stratify subgroups by a proxy for interruption costs, or variable that can be used to represent outage costs for the purposes of stratification. This step involves finding the optimal strata design (strata boundaries and sample allocations) using the Dalenius-Hodges method and the Neyman allocation, described below. The downside of stratification is that it can make administering the survey—and analysis of the results—more complicated for the study team. In choosing the strata, the CIC study team will need to weigh the benefits of including additional strata against the added costs and complexities of conducting the study.

4.2.2.1 Why Stratify?

Probability distributions of customer interruption costs have long tails to skewed to the right (i.e, a small number of customers report extremely high costs), similar to the consumption distributions in Figure 4-2. Customers with high interruption costs have a relatively low probability of being selected in a simple random sample. Stratification would target (i.e., oversample) this portion of the population and thereby achieve higher levels of precision than a simple random sample of the entire population (Sullivan & Keane, 1995). In other words, within-stratum variance will be smaller than the overall variation of a random, non-stratified sample of the entire population. Moreover, even though each customer does not have an equal probability of being selected due to stratification, they do have a non-zero, pre-determined probability of being selected, which is sufficient for obtaining unbiased estimates.

In addition to increasing the precision of the estimates, stratifying a sample can reveal how certain population parameters impact outage costs. For example, interruption costs may vary between certain areas of the utility's service territory, for customers with rooftop solar, or for customers on time-of-use (TOU) rates. Stratifying the sample along these lines will not only increase precision (if the variation is significant), but will allow the study team to see how being on a TOU rate or having rooftop solar impacts interruption costs on average.

4.2.2.2 Identifying Subgroups

!

The study team should attempt to identify subgroups of each customer class that may have significantly higher (or lower) interruption costs than the rest of the population. One important consideration is the potential for regional subgroups—particularly if there is large geographical variation across the utility service territory. To identify areas with high interruption costs, the team can analyze gross domestic product (GDP) per nonresidential kWh for each Metropolitan Statistical Area (MSA) (for example) in the service territory. Although 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.[18] Sullivan et al. (2012) used this approach to identify geographic subgroups in a VOS study for Pacific Gas & Electric (PG&E). Figure 4-3 shows GDP per non-residential kWh for each MSA in PG&E's service territory. Variation is high, with GDP/kWh ranging from less than $3 in rural California to over $13 in the Bay Area. Based on this analysis, the study team decided to stratify by Bay Area/non-Bay Area, and the results ultimately showed that outage costs normalized by usage were significantly higher in the Bay Area.

[18] For residential customers, household income is a good proxy for the geographic variation of outage costs normalized by usage.

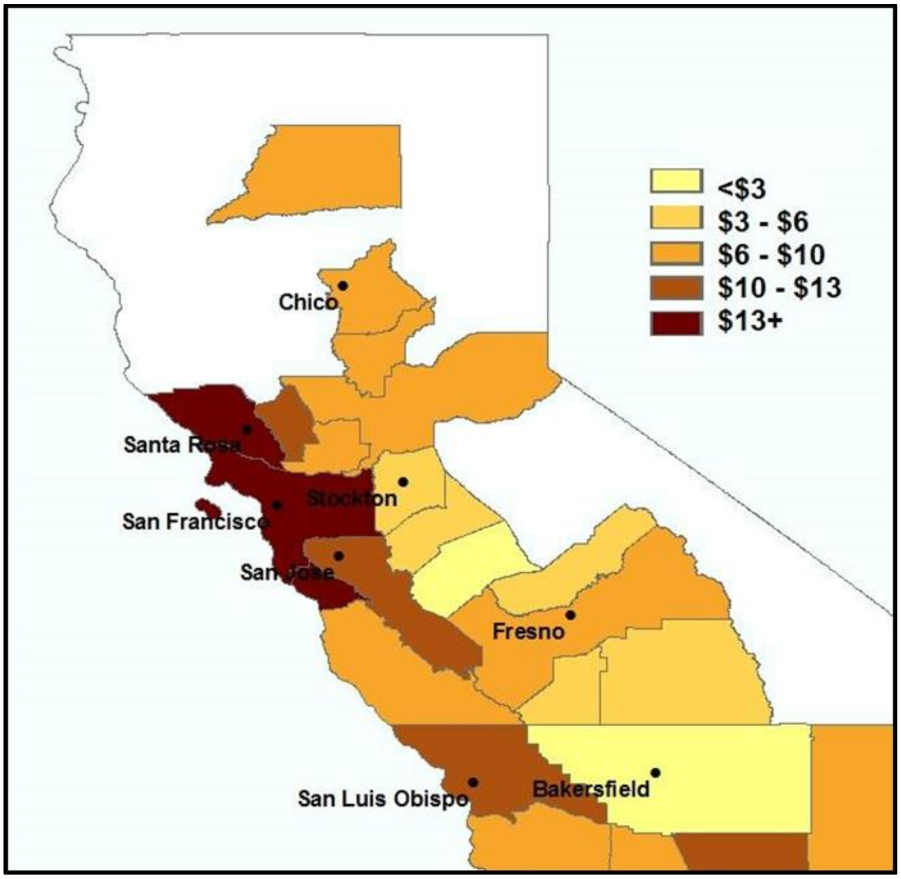


Figure 4-3. GDP per Non-Residential kWh for Each MSA in PG&E's Service Territory

Industry-level stratification can also be insightful in certain situations. The largest variation in interruption costs is generally among large C&I customers. These customers have different abilities for dealing with interruptions. For example, certain types of manufacturing facilities can shift production schedules if an outage occurs, while occupants of large commercial office buildings often cannot. Thus, customers that consume similar amounts of electricity each month could have very different interruption costs. Stratifying by industry could be beneficial if the ways in which the type of industry would deal with an interruption are different—and the study team suspects that differences in consumption would not accurately reflect the differences in interruption costs. A potential subgrouping scheme could be along the first 2 digits of the NAICS code (i.e. the “sector”).

The study team should also try to identify any individual, large C&I customers that would have outage costs much higher than other customers. Excluding these known outliers would yield CIC estimates that were biased low compared to a study that included them. These types of customers, such as refineries, would generally have lost production output from the interruption and may take several days to come back online to full production. If only a small number of these types of customers are present, the study should include all of them. Alternatively, the team could separate this particular subgroup and sample from it to improve precision.

4.2.2.3 *Stratifying Subgroups by Estimated Interruption Costs*

After examining the customers to identify potential subgroups for stratification, the study team may decide to keep the groupings at the customer class-level (e.g., residential, small/medium C&I), or identify subgroups below the customer-class level (e.g., geographic region, industry). Regardless, this Guidebook recommends stratifying each customer class—or subgroup, if the study team identified any—by a proxy measure for interruption costs. Ideally, the study team would stratify the sample based on the variable being measured—in this case, actual interruption costs. The next best option is a proxy measure. Many previous studies have used customer electricity consumption (i.e., usage) as a proxy. However, recent studies—and analyses related to developing the ICE Calculator—suggest that using the log of usage as a proxy works improves precision (Sullivan, et al., 2015). The log of usage is a more accurate functional form than usage itself for predicting interruption costs when modeling outage costs from the survey results (discussed below in Section 4.5.3). Another possibility is to use the underlying econometric models from the ICE Calculator to generate individual customer interruption cost estimates—and to use these estimates as a proxy for stratification purposes. The literature does not contain any cases where a study team has implemented this method, but we discuss this as an area for future experimentation in Section 6 of this Guidebook.

Optimizing sample stratification is a complex, technical undertaking that has been under-studied in the literature on survey design. Stratifying each customer class and/or subgroup by a proxy for outage cost involves employing a set of tested techniques and some experimentation. The authors recommend that the CIC study team employ a two-step process to achieve an optimal sample stratification scheme. In the first step, the team identifies optimal stratum boundaries using the Dalenius-Hodges method. Next, the team should determine the optimal allocation among the Dalenius-Hodges strata using the Neyman allocation. This two-step approach is particularly useful for measuring skewed populations and will maximize survey precision for a given sample size and number of strata (Sullivan & Keane, 1995).

The Dalenius-Hodges method determines the optimal endpoints for the customer usage strata given a predefined number of strata (Dalenius & Hodges, Jr., 1959). A Neyman allocation uses these strata boundaries to establish the optimal number of customers to sample from the final population in each stratum, given a fixed sample size (Neyman, 1934). In the Neyman allocation, the sample is drawn proportionally to the estimated variation in interruption costs across strata. Specifically:

Equation 4-2. Neyman Allocation[19]

$$\boldsymbol{n_h \propto N_h S_h}$$

Where:

- n_h = optimal sample size for stratum h
- N_h = population size in stratum h
- S_h = standard deviation of stratification variable in population in stratum h

[19] The symbol ∝ means "is proportional to."

Neither the Dalenius-Hodges method nor the Neyman allocation directly solves for the number of strata to use. That is, the number of strata is an input to the process rather than an outcome of it. To estimate the optimal sample design, including the number of strata, the study team can test different numbers of strata using Monte Carlo simulation techniques if data from a previous study is available. To illustrate this process for defining strata and examining the inherent tradeoffs, this section uses the sample design process from a PG&E VOS study (Sullivan, et al., 2012). The authors used a simulation to test several stratification strategies and selected the most appropriate one based on how well the strategies increased precision versus how much they complicated survey administration.

Sullivan et al. (2012) used data from a 2005 CIC study at the individual premise level to produce CIC estimates as a proxy for current interruption costs. The team tested eight different sampling strategies, using estimated interruption costs to stratify customers for a subset. Table 4-2 shows the eight strategies. Strategies three through seven used Dalenius-Hodges and Neyman allocation for the different numbers of predetermined strata ranging from two to 10. Strategy one did not use stratification (i.e., is a simple random sample). Strategy two used only Neyman allocation with equal strata. Strategy eight was identical to Strategy five, but this strategy used consumption as a proxy for usage instead of estimated interruption costs.

The simulation repeatedly drew from a random sample of 1,000 customers (with replacement) and calculated the mean of each reported (rather than predicted) interruption cost. Table 4-5 shows the standard deviation of sample means for each strategy and customer class. The "best" strategy for maximizing precision was the one that minimized standard deviation of the simulated results. The strategies with the lowest standard deviation for each customer class are highlighted in yellow. The table shows that the Dalenius-Hodges/Neyman strategies performed best for each customer class. For the small/medium business class, the best strategy had 10 strata. However, as discussed earlier, increasing the number of strata also increases the cost and complexity of implementing the survey. In this case, the study team decided that the difference in standard deviation between five and 10 strata was not large enough to rationalize doubling the number of strata.

Table 4-5. Standard Deviations of Mean Outage Cost over 30,000 Simulations by Class and Strategy (from Sullivan, et al., 2012)

Strategy Number	Strategy Description	Standard Deviation by Customer Class			
		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

It is unlikely that a utility will have data from a previous CIC study to perform a similar simulation. However, this experiment illustrates several points that can inform future studies. First, the stratified samples (Strategies two through eight) all performed better than the simple random sample, which was not stratified. Second, using both Dalenius-Hodges and Neyman to stratify the samples (Strategies three through eight) performed better than using only Neyman allocation. Third, predicted outage costs outperformed usage as a proxy for the two strategies that used four strata (Strategies five and eight). The log of usage is the key component of predicted outage costs and the findings from this exercise support the recommendation of using log of usage as a proxy for interruption cost. Finally, from this simulation—and other previous studies—selecting three to five strata is a reasonable balance between optimizing sample design and avoiding complexity.

The following bullet points summarize the stratification process:

- Select subgroups within each customer class based on study objectives and/or if there is evidence of significant interruption cost variation
- Determine the number of strata for each subgroup. In the absence of data from a previous study, we recommend using three to five strata as this range strikes a reasonable balance between performance and complexity. The number of strata may vary by subgroup and customer class.
- Use the Dalenius-Hodges method to find the optimal strata boundaries and the log of usage as a proxy for outage costs
- Use Neyman allocation to determine the sample size for each stratum

4.3 Step 3: Design Survey Instrument(s)

Summary: Design survey content and measurement protocols. The study team will use the survey instrument to elicit interruption costs and present information to respondents that can help respondents estimate their costs accurately. Structuring the survey properly will minimize bias by making sure that respondents stay engaged, understand the survey, and keep previous experiences in mind while considering hypothetical outage scenarios.

Recommendations:
- Limit the number of outage scenarios to 5-8 to avoid survey fatigue with respondents.
- For residential customers, implement a two-stage WTP measurement technique.
  - First stage: ask customers to consider how the outage would affect their household and to estimate their out-of-pocket and inconvenience costs.
  - Second stage: ask customers to indicate how much they would be willing to pay to avoid the outage.
  - Use the WTP measurement from the second stage in the analysis.
- Assign residential customers the same onset time for all hypothetical scenarios to minimize confusion.
- Conduct SMB customer surveys using a mixed-mode measurement protocol, with telephone recruitment and email/paper surveys depending on the customers' choice.
- Conduct large C&I studies in-person with personnel from the businesses who are familiar with the facility, operations and cost structure.
- Retired utility account representatives have an ideal background and skillset for conducting interviews.

Proper design of the CIC survey content and measurement protocols is a crucial step to minimize bias and ensure accurate estimates of customer outage costs. The ideal survey instrument will present customers with a limited set of hypothetical outage scenarios and ask questions about their response and the costs that they may incur under each scenario. In practice, an interruption cost survey consists of several survey instruments (and associated protocols for contacting respondents) that are customized for important customer classes (e.g., residential, large C&I, small and medium C&I). However, each of the survey instruments will contain a consistent set of materials as discussed below.

Each survey instrument—targeting a particular set of customers--contains a set of questions that each respondent will receive. The general format includes the following sections:

1. Introductory questions

Purpose:

- Ground to previous experience
- Provide relevant information
- Get subjects to start thinking about how much interruptions would disrupt their normal behavior

2. Interruption cost estimation scenarios

Purpose:

- Describe outage circumstances
- Ask how the specific outage would affect the home or business
- Elicit outage costs.

3. Questions about the respondent

Purpose:

- Obtain demographic information
- Obtain dwelling (residential) or facility (non-residential) information, such as square footage
- Ask about cost structure of business (non-residential)

4. Additional questions (optional)

Purpose:

- Determine acceptable service level
- General satisfaction with electric utility service

This section reviews the process of developing the survey instrument. Appendices B-D contain examples of actual instruments for residential, small and medium C&I customers, and large C&I customers. Researchers have used these basic survey questions and formats for many years to collect outage cost information for a wide variety of utility populations. In designing future outage cost survey forms, it is possible—and even likely—that study teams may need to customize the questions to measure particular issues. However, study teams should exercise caution when making significant changes to the format or content of the interruption cost survey so as not to introduce bias. In addition, if the study team wants to compare results to those of past studies, it should not make major changes to the instrument.

4.3.1 Present Introductory Questions

The first section of the survey should briefly explain the purpose of the survey. This explanation should be no longer than two to three sentences. This explanation typically emphasizes that the information being collected is important for ensuring the future reliability of the customer's electricity supply. In addition, this section directs the survey respondent to a contact person at the utility who can confirm that the survey is legitimate.

The first section of the survey also contains introductory questions designed to initiate customers thinking about outages that they have experienced in the past and how these outages may have affected their ability to operate their facilities or meet their household needs. These questions should ask respondents—regardless of customer class—about their recollection of past outages (momentary and extended) over the past 12 months. Questions of this nature allow the study team to gather important information about customers' awareness of past service reliability. Also, respondents will be better prepared to answer questions throughout the rest of the survey, as they can anchor their responses regarding hypothetical outages to past outages that they may have experienced. Examples of introductory questions are included in Appendices B-D (depending on customer class).

4.3.2 Describe Power Interruption Scenario

The survey instrument elicits customer interruption costs by describing outage scenarios and then asking the respondent to indicate their corresponding costs. This section typically presents five to eight outage scenarios which contain information on a set of characteristics describing the outage event. The authors recommend no more than eight scenarios to avoid survey fatigue with respondents. Not surprisingly, the outage scenario characteristics vary within and across customers and often include information about the:

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- Season (usually summer and winter)
- Type of day (weekday or weekend)
- Weather conditions (hot summer or cold winter)
- Duration of interruption
- Outage start and end time
- Amount of advance notice given
- Cause of outage (planned vs. unplanned)

Survey Fatigue

Respondents tire of answering questions and rush to finish the survey. They do not take the time to carefully consider responses and thus can introduce bias into the study. Keeping the survey length reasonable minimizes the risk of fatigue.

Figure 4-4 shows an example of an outage cost scenario that was presented in an actual residential survey.

Case B:
On a **hot summer weekday** a complete power outage (total loss of electricity) occurs at **3:00 p.m.** without any warning. You do not know how long it will last, but after **one hour** your residence's electricity is fully restored. Remember, none of the described outages are caused by storms or forces of nature.

SUMMARY:

Conditions:	Hot summer weekday	**Start time:**	3:00 p.m.	**Duration:**	1 hour
Warning:	No advance notice	**End time:**	4:00 p.m.	**Frequency:**	1 time

Figure 4-4. Example of an Interruption Cost Scenario

It is important to align the scenarios with the overall purpose for the study (e.g., generation, T&D). Consequently, the characteristics of certain scenarios will depend on the type of study. For example, generation-related outages have distinct characteristics, so scenarios in CIC studies focused on generation should mirror the general conditions of these types of interruptions. Unplanned generation-related outages often occur during system peak times, which are hot summer weekdays or cold winter mornings. Regulators require utilities and system operators to manage their reserve margins so that unannounced blackouts are extremely unlikely. Occasionally, utilities are forced to implement emergency curtailments (rolling blackouts) when reserve margins are projected to fall below certain minimums. As part of these plans, utilities usually give customers 24 hours advanced notice of impending generation outages resulting from rolling blackouts. It is also possible that unexpected events—which sometimes occur outside the utility's service territory—cause widespread, unannounced generation-related outages. For this reason, generation planning studies usually consider the possibility of widespread outages with little or no warning.

For T&D planning, unplanned interruptions can occur at any time of the day and year. For this reason, CIC studies must estimate interruption costs for all times of day including for both weekdays and weekends. This wide range of possibilities presents challenges when developing outage scenarios, because respondents have a limited number of scenarios that they can cognitively process (up to eight power interruption scenarios). Unfortunately, early efforts to measure interruption costs for T&D customers provided limited variation in the onset times for outages, whether weekday or weekend, morning, afternoon, or evening.

Fortunately, researchers have developed a more refined technique for varying the outage onset times in the scenarios in large part due to advances in customizable web-based surveys. The technique allows for study teams to estimate outage costs for a wide range of day types and onset times. These methods often rely on historical (observed) information about outages in the development of scenarios. Figure 4-5 shows the distribution of 2008–2010 power interruptions by onset time and customer class for the PG&E study mentioned earlier. Power interruptions are distributed throughout the day for all customer classes and no single hour for any customer class accounts for more than 7% or less than 2% of outages. In this specific example, the study team decided to assign hypothetical onset times to respondents for T&D outages in proportion to the percentage of the utility's power interruptions that begin at that time. The authors recommend assigning each residential respondent the same onset time for all scenarios in order to minimize the effort respondents had to make to understand the outage circumstances, as was done for this example. Different customers received other onset times, which were the same for all scenarios. Non-residential surveys included some variation across onset times. This approach produced data that allowed researchers to estimate interruption costs for T&D outages occurring at all times of the day and night.

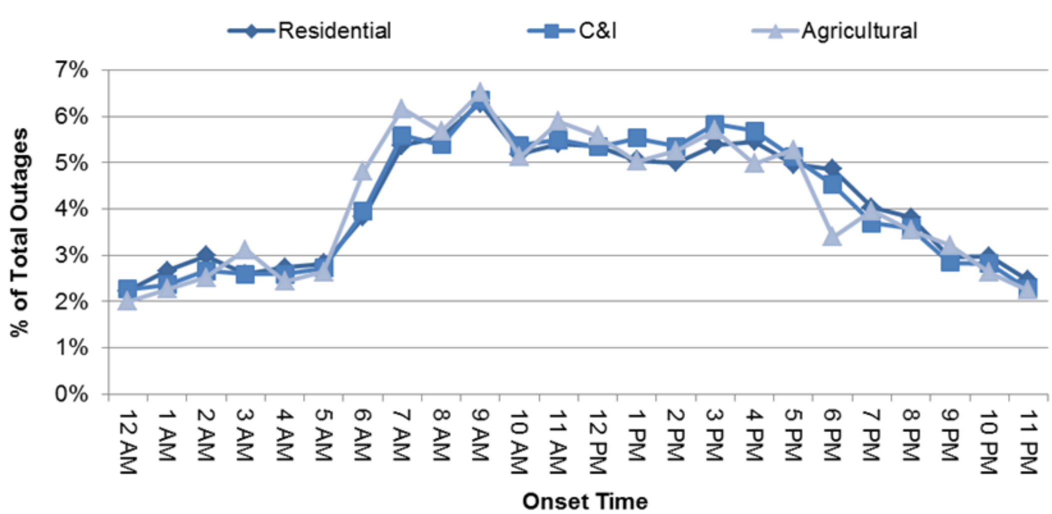

Figure 4-5. Distribution of Outages by Onset Time and Customer Class (2008-2010)

4.3.3 Elicit Direct Costs (Non-Residential Customers)

4.3.3.1 Small and Medium C&I

The authors recommend that the study team conduct SMB customer surveys using a mixed-mode measurement protocol. Under this protocol, a member of the team makes a telephone call to the sampled business to locate the employee who is most qualified to answer the survey questions. Second, the study team sends a mail-based survey or URL address to complete the survey online. After describing each scenario, the survey instrument asks a series of questions in order to obtain cost estimates for the different elements of the business' cost equation: labor costs, direct damage costs, other tangible costs, etc. The survey instrument then asks the respondent to estimate the overall interruption cost—under each scenario—using a range of possibilities: best case, typical case, and worst case. It should be noted that the survey only asks the SMB customers to provide their estimate of the overall costs for the best case, typical case and worst cases—not for each cost element. Asking the customers to provide detailed outage cost information for only the first scenario significantly reduces the burden of the survey exercise, leads to higher response rates, and customers staying focused on the estimation scenarios. The study team should analyze the survey results using the 'typical case' scenario. The best and worst case scenarios still provide a purpose by giving respondents the opportunity to express the uncertainty associated with their individual CIC estimate. Researchers believe that this process produces improved estimates for the typical case. Appendix C contains an example of a survey instrument that was administered to a small commercial and industrial customer.

4.3.3.2 Large C&I

Interviewers conduct CIC surveys in-person for large C&I customers. This practice ameliorates the difficulties that survey respondents have with estimating large C&I outage costs quickly and accurately. Qualified interviewers typically have experience and/or education in industrial engineering, facilities management or business administration. The ideal interviewer has experience with the issues that large commercial and industrial electricity customers face as a result of reliability and power quality issues. In past studies, retired utility business account representatives have proven to be the best interviewers for collecting outage cost information from large C&I customers.

The survey for large C&I is similar to the small/medium C&I instrument in that it asks the subject about the various components of the direct cost equation. However, the equation used by the large C&I interviewer is disaggregated in order to collect additional information about costs. Larger, sophisticated C&I facilities tend to track more detailed information. It is important to ensure the accuracy of this information given the large magnitude of outage costs typical to this class of customers. Survey instruments for large C&I customers often elicit information about production schedules and processes, which is information not usually requested from SMB customers.

Not surprisingly, certain types of facilities may have very different responses to an outage than others—some responses may be quite unique given the nature of the facility and industry. For example, most hospitals have a robust backup power system, but they still are not able to perform non-emergency surgeries during the interruption. The hospital's economic losses from halting non-emergency surgeries can be very significant. It is important for interviewers to know about common issues with these types of customers, so that they may effectively probe the customer about their past experiences during the onsite interview.

4.3.3.3 Dealing with Rented or Leased C&I Facilities

Generally, when a large C&I facility (e.g., manufacturer, hospital, warehouse, transportation operator, educational facility) experiences a power outage, the operator of the facility is the only party that bears the direct costs from the outage. However, important exceptions arise when companies rent or lease all or part of their master-metered facilities to at least one other business. This situation most commonly occurs with commercial office buildings.

The sample frame for commercial and industrial customers is the population of C&I premises. Utilities generally define a C&I premise as the area of a given facility paid for by a particular enterprise or company. The premise usually comprises all of the utility meters at a given site that is owned by single business. A premise is not limited to buildings—as electricity is often consumed outside of buildings—and it is not the same as an account. A building may contain multiple premises (as often occurs in commercial office buildings and malls) and a premise may contain multiple buildings (as often occurs in a manufacturing facility).

Commercial office buildings often contain multiple premises – with some areas (e.g., ground floor restaurants and shops) served by their own meters and paid for directly by the tenants of the building—and other areas (e.g., common areas and tenant-leased spaces) paid for by the building owner/operator. The single meter serving the office building will probably be included within the large C&I sample frame. If this premise is part of the sample, the building operator will be asked to report its interruption costs. The building operator's costs will be relatively small, because the operator will not lose revenue except in extremely rare circumstances when the power is out for a long enough time to trigger a dispute under the terms of the lease.

If the study team surveys the building operator (who pays the bill for the master meter), it will not observe the interruption costs for the building's tenants (who are served by the master meter). The tenants are not part of either the SMB or large C&I sample frames as they do not have accounts with the utility. The study team can view this situation in one of two ways. Strictly speaking, given the sample design, it may be appropriate to simply ignore the losses of the tenants (however real or large), because they are not experienced by anyone directly served by the utility. They are indirect losses, or losses experienced by parties downstream of the utility customer, and CIC studies generally do not account for indirect losses, as they are almost impossible to reliably estimate. On the other hand, economic losses from tenants in office buildings could be very significant in some locations and circumstances (e.g., downtown urban core areas). In some densely populated urban areas, master-metered residential buildings may present a similar problem. If the study team believes that these costs are likely to contribute significantly to the total cost (e.g., the service territory contains many master metered buildings), they should try to include these costs in the study.

If the study team makes the decision to include interruption cost estimates for tenants, it must collect information from facility operators that will allow it to impute tenant outage costs from a separate sample of tenants. At a minimum, this means that it must record the floor area occupied by tenants and the number of tenants in the premise during the facility operator interviews. Section 4.4.4 describes procedures for sampling tenants under this specific circumstance

4.3.4 Elicit Willingness-to-Pay (Residential Customers)

It is important to ensure that residential survey respondents think carefully—before beginning to estimate outage costs—about how a power interruption might affect their ability to use appliances, electronic devices, and other facilities within their household. The survey should ask customers about how their household would adjust its behavior during and after the outage, which also serves to remind them about how an interruption may disrupt their current household operations. Rooftop solar has achieved significant market penetration in some places and customers may be able to couple rooftop solar with battery systems. However, customers may not know that it is still possible to lose service during a power outage—even with some of this equipment being installed. The survey should be used to remind customers that possibilities like this exist.[20]

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Surveys of residential customers should ask respondents to consider three cost components: (1) inconvenience costs; (2) out-of-pocket expenses; and (3) overall WTP to avoid the outage. Eliciting estimates for inconvenience costs and out-of-pocket expenses can help the respondent be sure they are considering all potential factors and also be more systematic about generating their WTP estimates. Inconvenience costs represent the hassles the customer incurs during the outage. These inconveniences may include having to use candles in the dark, not being able to watch television, or not being able to use the internet. Out-of-pocket expenses may include food spoilage, dining out, or lost wages for lost work time—that the respondent's employer would have to incur—due to outages.

For questions related to WTP, the study team should word the question(s) as if a temporary backup service were available that was not associated with the utility. Figure 4-6 shows a survey question with this type of wording. Following this process can avoid the situation where customers react that the utility should be providing this enhanced service for the price the customer already pays—a common reaction to WTP questions about reliability. Wording the questions this way also reduces the likelihood that a customer's potential dissatisfaction with the utility influences his or her WTP. In the past, survey instruments usually specified that the backup service was being performed by a backup generator. The authors believe that a better option would be to keep the generation technology unspecified (i.e. "temporary backup power service") in case of any positive or negative associations customers may have with specific technologies.

[20] Level of preparedness is relevant in CIC studies that quantify the impact of longer-duration outages. Asking customers about their current level of preparedness for an outage not only puts the issue front of mind for them, but their answers may be useful for follow-on studies that may evaluate the economics of being resilient to power interruptions. See Section 6 for further discussion.

As discussed earlier (Section 3: Review of Methods), the authors recommend eliciting WTP by providing a range of options for respondents. Figure 4-6 shows a WTP question that presents a range of options from which the respondent may select. The range contains fifteen options ranging from $0 to $100. The distribution of values is clustered around the lower dollar amounts, with the median value ($50) as the third highest amount. The range should include a $0 option and an "other" option. This "other" option allows the customer to enter a value that is not listed—either within the given range or outside of it. If the subject answers with a value of $0, the survey should ask a follow-up question to confirm that the backup service is indeed worth nothing to the customer.

The study team can use the response to the follow-up question to eliminate responses from customers who are exhibiting status-quo bias, or are otherwise not providing a valid response to the WTP question. (Respondents exhibiting status-quo bias will choose the $0 option because it is the current "baseline" or "do nothing" option, even though the backup service is worth something to them.) For example, customers sometimes say that they are unwilling to pay for the backup service because they believe they are already paying too much for service or they think it should be included in the current level of service. This is the answer to the question "Do you think you are paying too much for service?" not "How much are you are willing to pay for a value-added service?" The study team should remove customers that exhibit responses similar to this example prior to calculating the results.

A4. Suppose a company (other than [Utility]) could provide you with a temporary backup power service to handle all of your household's electricity needs during this particular outage. With this backup service, you would not experience the outage and would not have to make any adjustments.

Please indicate the one-time amount you would be willing to pay for this backup service to avoid this particular outage. *(Please circle or specify one amount.)*

$0 $1 $3 $5 $7 $10 $12 $15 $20 $25 $30 $40 $50 $75 $100

A4a. **If you circled $0 in question A4**, is that because the service is really worth nothing to you or is there some other reason? (Check one)

☐ Worth nothing
☐ Other reason (please explain)

____

____

Figure 4-6. WTP Question for Residential Survey Instrument

4.3.4.1 Special Considerations: Customers Who Work from Home

Studies have generally only used the overall WTP value for calculating outage costs when eliciting inconvenience costs, out-of-pocket expenses, and WTP. Over the last decade, the workforce has seen a growth in employees who work from home. During 2015, 24 percent of employed people in the U.S. did some or all of their work at home (Bureau of Labor Statistics, U.S. Department of Labor, 2016). The share of workers doing some or all of their work at home grew from 19 percent in 2003 to 24 percent in 2015. Among the non-self-employed population, the number of people who work from home has grown by 115 percent since 2005 (Global Workplace Analytics, 2017). The growing at-home (tele-commuting) workforce introduces challenges when attempting to accurately estimate the full outage costs that some of these customers experience.

The full cost of the interruption should be captured in the WTP value for customers who work at home and are self-employed. However, a WTP measure may not fully capture the costs of the interruption in certain situations where customers who work from home are not self-employed. These discrepancies are most prevalent when customers earn an hourly wage, experience an outage long enough to disrupt work, and are unable to make alternative arrangements to complete the work. One example might include a virtual call center employee who works from home and is compensated at $10 per hour. This employee could lose $80 in “out-of-pocket expenses” if they experience an 8-hour outage and cannot make alternative arrangements to complete the work. However, they would likely be unwilling to pay $80 to work an 8-hour day and break even for their time working. In this case, the employer experiences a productivity loss, but the study team would not be able to account for this loss.

The study team can work within the existing framework of the survey to account for these discrepancies when they arise. The survey could include two introductory questions to account for the losses described above. First, a properly designed survey should ask whether—and how often— the customer works from home. Second, if the customer does work from home, the respondent should be asked whether the customer is self-employed. In cases where a customer works from home and is not self-employed, out-of-pocket expenses can replace WTP, but only in cases where these expenses are greater than WTP.

4.3.5 Measure Acceptable Levels of Service Reliability

Utilities as well as regulators typically consider customer equity and satisfaction when making investment decisions that could result in differentiated reliability levels within a service territory. They would not want reliability levels to be high for some neighborhoods and low for others to the point where residents considered it unacceptable. Apart from the issue of equity, utilities track customer satisfaction levels, often setting internal company goals that factor into employee bonuses.

A properly designed CIC survey can collect information that allows utilities to establish a minimum, acceptable reliability level for different customer types and regions. The survey instrument could ask customers about what levels of reliability they consider “acceptable” versus “unacceptable.” A proven technique is to use reliability “packages” for each customer class with specific descriptions of reliability.

Figure 4-7 shows an example of this type of question. In this example, the outage duration is “5 minutes or less”, but it was followed with 3-4 additional questions (not shown) containing different durations.

ACCEPTABLE LEVEL OF RELIABILITY

[Utility] works hard to prevent power outages, but eliminating all outages would be very costly, if not impossible. The following questions help us understand what you consider an acceptable level of service reliability from [Utility].

If each of the following occurred, would you think you were getting an acceptable or unacceptable level of service reliability?

6. An outage lasting **5 minutes or less...** (Check one box on each line.)

	Acceptable	Unacceptable	Don't Know
Once a week	☐	☐	☐
Once a month	☐	☐	☐
Once every 3 months	☐	☐	☐
Once every 6 months	☐	☐	☐
Once a year	☐	☐	☐
Once every 5 years	☐	☐	☐

Figure 4-7. Survey Question for Acceptable Level of Reliability

4.4 Step 4: Administer Survey

Summary: Conduct the survey using the appropriate approach based on customer class. Allow ample time for recruiting customers, following up multiple times with sampled customers, and collecting data.

Recommendations:

- Allow at least three months to administer the survey and collect the data.
- Provide training to all parties who will be interacting with customers.
- Inform the utility’s customer contact center that the study is occurring so that customer service representatives can verify the study’s legitimacy to customers who inquire.
- Provide non-contingent incentives ($2-$5) to residential customers and larger contingent incentives to non-residential customers.
- Leverage utility account representatives to help recruit large C&I customers to participate in the study.
- Account for master metered building tenants after drawing the sample.
  - Survey 5-10 tenants using SMB protocols and scale up to estimate interruption costs for all tenants.

The fourth step in conducting a CIC survey is to administer, or conduct, the survey. Section 4.1.3 discussed the option that utilities have to hire a third party market research firm to assist with various components of the study. This arrangement can have advantages for the administration phase of the study. Utility-sponsorship of a third-party administered survey gives credibility to the market research firm and also minimizes potential bias from customers altering responses if they have had issues with the utility in the past and think they are responding to the utility directly. This arrangement should lead to relatively higher response rates while also increasing the chances that customers answer the questions truthfully.

Table 4-6 provides an overview of a standard implementation approach by customer class. The CIC study team—along with its partners at the market research firm (hereafter the "CIC survey implementation team")—may choose to customize the approach based on their knowledge about the customer base and experience conducting surveys in the past. Implementation teams have used this effective approach in dozens of outage cost surveys while also keeping administration costs reasonable.

Response rates will vary from utility-to-utility and by customer class based on a number of factors. However, past experience has shown that response rates will typically range from 30% to 50%--regardless of customer class. The "Solicitations" column (Table 4-6) shows that the study team should plan for a response rate of about 33% for each customer class.[21] The implementation team should provide non-contingent incentives ranging from $2-5 for residential customers willing to consider participating in the survey. It should offer SMB customers $30-$50 and large C&I customers should receive $100-$300 for completing the survey. Providing incentives is a critical component to ensure the success of outage cost surveys, because completing the surveys requires a lot of effort and response rates have been shown to be highly sensitive to the inclusion—and size—of incentive payments. The CIC survey implementation team should include the residential incentive payment with the initial solicitation letter. Literature on survey response rates suggests that providing prepaid incentives—as opposed to waiting until after the customer completes the survey—significantly improves response rates to mail-based surveys (Singer, 2002).[22]

Table 4-6. Overview of Standard CIC Implementation Approach

Customer Class	Sample Design Target	Solicitations	Incentive	Time of Incentive Payment	Recruitment Method	Data Collection Method
Residential	1,000-1,500	3,000-4,500	$2 to $5	Upon solicitation	Letter	Mail/Internet Survey
Small and Medium C&I	1,000-2,000	3,000-6,000	$30 to $50	After completion	Telephone	Mail/Internet Survey
Large C&I	100-200	300-600	$100 to $300	After completion	Utility Account Reps & Telephone	In-person Interview

[21] An exception to this guideline is that if the utility expects its account representatives to be particularly effective at recruiting large C&I customers, the study should start with a number of solicitations closer to the sample design target for the large C&I segment.

[22] A likely explanation is that receiving the incentive upfront evokes a sense of obligation and induces potential respondents to respond.

! It is important to note that administering the survey and collecting the data will require at least three months. Before administering the survey, it is important to provide training to all parties who will be interacting with potential respondents (e.g., call center and customer representatives). For example, call center staff may be required to answer questions from customers about the CIC survey process or background on the role of the third-party implementer. It is essential that the study team follow up multiple times with sampled customers during recruitment in order to ensure high response rates and representative survey results. It is also important to give customers a few weeks to complete the detailed survey. In some cases, business may require input from other parties before completing the survey. The following sections discuss data collection procedures that should be followed for each customer class.

4.4.1 Residential Customers

CIC survey implementation teams generally conduct residential surveys online or by mail (if the respondent desires to do so). The implementation team should distribute the surveys to the target respondents in two waves. In the first wave, respondents should be sent an introductory letter on the utility's stationery explaining the purpose of the study and requesting their participation. The letter should include a non-contingent ($2-$5) incentive for all target respondents. The letter should also contain a URL and respondent ID number so that respondents can complete the survey online. The study team should send to customers—for whom the utility has email addresses—an email invitation to complete the survey online, timed to arrive at about the same time as the solicitation letter and incentive. The team should send the email solicitation approximately five days after it mails the solicitation letter. The implementation team should follow up with several email reminders to these parties in the days following the first email solicitation.

Two weeks after mailing the first wave of surveys, the study team should send a reminder letter along with a paper copy of the survey to respondents who did not complete the online survey. The letters and survey packet should include a toll-free phone number (with the appropriate call center routing) that respondents can call to verify the legitimacy of the survey and ask any questions that they might have about the process or organizations involved. It is important to note that the second survey solicitation should not contain an additional incentive payment.

4.4.2 Small & Medium C&I Customers

The CIC survey implementation team should use a two-stage process to survey small and medium C&I customers. In the first stage, the team should contact sampled businesses by telephone to identify the appropriate individuals (usually a business or facilities manager) for answering questions related to energy and outage issues at that company. During this recruiting process, the team should secure a verbal agreement from these individuals to complete the survey. Telephone interviewers should explain the purpose of the survey and indicate that a $30-$50 incentive payment will be paid—upon completion of the survey—as a 'thank you' for participating. In some cases, business representatives will refuse monetary incentives, because their internal policies prohibit receiving such compensation. In this situation, the implementation team should give the respondent the option of identifying a charity that will receive a donation in their name. Often, this alternative leads to participation by businesses which were initially unable to participate because they could not accept monetary compensation.

Next, the survey implementation team gives the individuals who agree to participate the option of receiving the survey in the mail or completing it online. Those who elect to complete the survey online should receive an email containing an individualized survey link—the others should receive a survey package containing the following:

- Additional explanation of the purpose for the research
- Simple instructions for completing the survey questions
- A telephone number to call if they have questions about the research (or wish to verify its authenticity)
- The survey booklet (or a link in the email to compete the survey online)
- Return envelope with pre-paid postage (for the paper survey option)

One week after emailing the survey link, the survey implementation team should call respondents to remind them to complete the survey. Customers who request regular mail should receive the first reminder calls two weeks following the mailing. About 10 days after the email participants' reminder calls, the team should resend the email to anyone who did not complete it. If a respondent does not complete the survey within 10 days, then the team should (1) assume that the customer will not complete the survey and (2) not contact them again. The implementation team should mail incentives to customers immediately upon receipt of their completed surveys.

4.4.3 Large C&I Customers

The CIC survey implementation team should work closely with the utility's business customer account representatives to engage with large C&I customers during the recruitment phase. The survey asks about production cost information that customers—particularly manufacturers—may consider sensitive. Utility involvement is necessary to achieve as high of a response rate as possible for large C&I customers. The recruitment process begins with the list of sampled large C&I customers, which the study team provides to the utility and its account representatives. The utility representatives should make the first contact with each sampled large C&I customer regarding the study to identify the best person at each business for the implementer to call, ask to participate in the survey and, if they agree, provide the contact information to the survey implementation team. The study team should make no further attempts to recruit large C&I customers who, at this point, indicate that they are not interested in participating in the study.

The utility will ideally provide to the survey implementation team the contact at each company that agreed to participate in the study. A member of the implementation team—ideally an experienced telephone contact rep—should then call the designated person at each of the sampled premises. The target respondent will usually be a plant manager or plant engineering manager—or someone else who is very familiar with the cost structure of the enterprise.

The telephone rep should set up an appointment with one of the survey implementation team's executive interviewers. Once the appointment is scheduled, the team should email the customer a confirmation along with a written description of the study and an explanation of the information that they will be asked to provide. The interview should be scheduled at the convenience of the customer. The survey implementation team should offer a financial incentive ranging from $100-$300 for completing the interview. On the agreed upon date, the executive interviewer should visit the sampled business and conduct the in-person interview. If needed, the interviewer can also provide the interview scheduling information to the utility's account representatives.

4.4.4 Special Considerations: Master Metered Commercial Buildings

As discussed in Section 4.3.3, it is likely that the large C&I sample will include some multi-tenant office or residential buildings (e.g., high rise buildings). In these situations, it is often the case that building management pays the entire electricity bill for tenants. The landlord will generally incorporate the cost of the utility bill in the fixed monthly lease amount. The customer that the utility would identify for the sample is the landlord that pays the bill for the premise, but it is the tenants who experience the losses from a power interruption. The study team could elect to ignore master metered building tenants' interruption costs, as they are indirect costs. In some cases (such as when the service territory contains a substantial number of master-metered buildings), CIC study teams may choose to include them. The study team must estimate the costs for the tenants within master metered buildings to properly estimate interruption costs for the entire premises. Fortunately, there are a number of different methods to accomplish this.

One approach is to identify all master-metered buildings ahead of time and account for this particular characteristic as part of the sample design process. In this approach, the sample designers would form a segment sample for master metered buildings and, from this segment, select a cluster sample of buildings. They would also specify a fixed number of tenants to be sampled from each building. The study team can calculate the interruption costs for this segment using conventional survey weighting techniques. This approach is reasonable, but it involves a lot of upfront effort in the sample design process.

!

The authors recommend accounting for master-metered building tenants after drawing the sample. To carry out this approach, the study team must identify tenant-occupied master metered premises during the process of surveying large C&I customers. The initial telephone recruitment process provides a good opportunity for the study team to inquire about whether the premise is master metered. The executive interviewer can confirm the arrangement at the interview and, if the premise is master-metered, determine the amount of tenant occupied space served by the master meter as well as the total number of tenants occupying space in the premise. Following this step, the interviewer conducts the survey for the building operator following the normal approach for large C&I customers discussed earlier. After surveying the customer with the master meter, the study team should identify a sample of the premise's tenants for the purpose of eliciting their interruption costs. It is unlikely that the building owner will divulge contact information for the tenants, so the study team must either obtain a list of tenants using the building directory or perform a "reverse lookup" of building occupants using an online source.

The question of how many tenants to survey in each building presents a problem. The utility—and thus the study team—does not have access to electricity consumption data from the tenants, as its customer is the building landlord. Without consumption data, the study team is missing crucial information for designing a sample for each building. Previous studies have attempted to complete interruption cost surveys with 5 to 10 tenant businesses occupying the master metered premise (Sullivan, et al., 2012). In the absence of empirical studies showing better ways to design the tenant sample, this Guidebook recommends surveying 5 to 10 tenants per master metered premise. How to account for interruption costs of master-metered buildings is an opportunity for further research.

The survey protocols for this process are the same as those for SMB customers. When conducting the survey, the study team should collect data on the floor area that each tenant occupies. This information is used to scale up the outage costs from the sample of tenants to the entire large C&I premise. For example, the team could obtain outage costs from businesses accounting for 100,000 square feet of building space comprising 500,000 square feet of total rentable space. The total interruption cost can then be scaled up by multiplying the sampled interruption costs by a factor of five.

4.5 Step 5: Analyze Survey Results

Summary: Clean the data and develop customer damage functions that estimate interruption costs over the full range of possible scenarios. Use visualizations to communicate interruption cost estimates and how they vary by the characteristics of the customer, outage, or environment.

Recommendations:

- Drop outliers from the data, including the highest 0.5% outage cost per unit of energy consumption for the residential and SMB segments as part of the initial data cleaning process.
- Use a two-part regression model specification for the customer damage function. For the first part, specify a probit model; for the second part, specify a Generalized Linear Model (GLM).

4.5.1 Data Cleaning and Validation

Data from the completed surveys will contain outliers for outage cost. Some outliers are reasonable and some are due to errors in interpretation. Respondents may erroneously provide unrealistically high estimates when taking the survey due to human error or through a basic misunderstanding of one or more questions. Before metrics are calculated and the customer damage function modeled, these erroneous outliers should be removed. The authors recommend dropping 0.5% of the highest residential and SMB responses for outage cost per unit of energy consumption. This percentage is somewhat arbitrary, but has proven to be a useful data cleaning step for CIC survey data and removing responses that are clearly implausible.[23] Dividing the outage cost by energy consumption ensures that one is not merely dropping the responses from the largest customers. Use judgement to determine if more responses should be discarded if respondent answers are obviously invalid (e.g., respondents entered the same answer for every question).

Non-response bias in surveys occurs when respondents differ in meaningful ways from non-respondents. The CIC study team can analyze survey response trends for non-response bias using a probit model. Models should be developed for each customer class using all of the sampled records, with a binary dependent variable indicating whether or not the respondent completed the survey. The probit models will reveal the variables that contributed to the likelihood that a customer completed the survey. If any variables which were not part of the stratification scheme significantly affected the likelihood of completing a survey, non-response bias may be present in the results and post-stratification adjustments may be required.

> ***Probit Model***
>
> A probit model is a type of regression model designed to estimate probabilities. In this case, the model would estimate the probability that a customer would complete the survey based on the customer's observable characteristics.

Another way to check for non-response bias is to see if customers who answered the survey earlier in the study period valued interruptions differently than those who completed the survey only after multiple solicitations. Customers who felt more strongly about outages and valued them more highly may have been more inclined to answer the survey right away. Different CIC estimates, while controlling for observation characteristics of respondents, would suggest that those who responded to the survey were not representative of the customer population (Johnston, et al., 2017).

4.5.2 Estimation of Key Reliability Metrics

CIC studies can generate a number of metrics that normalize customer outage costs by demand (kW), consumption (kWh), time, number of events, etc. The CIC study team can generate the specific metrics it needs based on its planning and/or regulatory purposes. Six of these key metrics are described below.

- **Cost per Outage Event**: the average cost per customer resulting from each outage event. Given the dynamic survey instrument design for T&D outages, these values represent the average outage cost across all onset times. The metric is derived by calculating a weighted average (by usage category and region, if applicable) of the values that the respondent provided on the survey to each outage scenario. As each scenario on the survey focused on a specific outage event and then asked the respondent to provide the cost estimate, the respondent was essentially providing the cost per outage event estimate.

[23] For a more thorough discussion of outliers in the ICE Calculator meta-database, see Sullivan et al. (2009).

- **Cost per Average kW**: 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. It is derived by dividing average cost per outage event by the weighted average customer demand among respondents for each outage duration by customer class. The average demand for each respondent is calculated as the annual kWh usage divided by 8,760 hours in the year.

- **Cost per Unserved kWh (also known as Cost of EUE):** the cost per outage event normalized by the expected amount of unserved energy (in kWh) for each outage scenario. This metric is useful because utility planners can easily apply it to their analyses, where the amount of unserved kWh from an outage is commonly available. For each duration and customer class, average cost per event is calculated and then divided by the expected unserved kWh, which is the estimated quantity of electricity that would have been consumed if an outage had not occurred. As the outage scenarios occur during various times of the day and week, we may not simply multiply average customer demand (from the cost per kW metric) by the number of unserved hours to get the expected unserved kWh estimate. Average customer demand must 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.

The load ratios are the ratios of expected kW (during a specific time interval for a given customer) to average kW. Each respondent may have a specific load ratio based on rate profile and outage scenario. Equation 4-3 shows the formula for expected unserved kWh (where *i* denotes each customer).

Equation 4-3. Expected Unserved kWh

$$\boldsymbol{Expected\ Unserved\ kWh = \sum_{i=1}^{n} Avg.Demand_i\ x\ Load\ Ratio_i\ x\ Unserved\ Hrs._i}$$

- **Cost per Customer Minute Interrupted**: cost per customer per minute for actual outages that occurred in the past. This metric uses outage costs by customer class and applies them to actual outages that occurred. When averaged over a particular period of time, it can be useful as a planning input when utilities have an outage forecast in terms of customer minutes.

- **Cost per Momentary Interruption**: average cost per customer from outages defined as "momentary interruptions." Different utilities have different thresholds for defining a momentary interruption, but momentary interruptions typically last five minutes or less.

4.5.3 Econometric Modeling

The survey yields a discrete set of responses with specific outage start times and durations. To be able to apply the results to other customers and for outages with different characteristics, it is necessary to develop customer damage functions. Customer damage functions relate outage costs to a set of variables describing the interruption attributes, customer characteristics and environmental attributes.

4.5.3.1 Nature of Interruption Cost Data

Generally, interruption cost data has a few issues that present modeling challenges. If the outage cost response data was normally distributed, ordinary least squares (OLS) would be a good candidate for specifying the model. However, interruption cost data is not normally distributed. Many customers report zero costs—both for the WTP for residential customers and the direct costs for C&I customers. In this case, certain residential customers do not suffer enough inconvenience to make it worthwhile to pay to avoid the outage. Similarly, C&I customers may be able to shift production schedules without incurring any costs—or they are not adversely affected by short outages.

! The other complicating issue with outage cost survey data is that it tends to have some very large values for outage cost and electricity usage—even after removing some of the extreme outliers (see Section 4.5.1). The distributions of these two variables have very long tails to the right. Skewed electricity usage data is typically addressed by taking the logarithm of the value and using the transformed variable in the model. Unfortunately, this transformation changes the interpretation of this coefficient, but it produces a distribution that more closely resembles a normal distribution. For outage cost, it is important to follow a two-step approach, which has proven to be effective for estimating customer damage functions (Sullivan, et al., 2009).

4.5.3.2 Two-Part Regression Model Specification

The first step involves estimating the latent probability that customers experience a non-zero outage cost with a probit model, based on a set of independent predictor variables related to the interruption, the customer, and the environment. The model estimates and retains these probabilities. In the second part of the approach, a Generalized Linear Model (GLM) relates outage costs to a set of independent variables only for those customers who reported outage costs greater than zero in part one.[24] The second step involves estimating outage costs for all customers—even those customers who reported zero cost values. Finally, multiplying the probabilities from step one by the outage cost estimates generated during step two produces the final outage cost estimates.

4.5.3.3 Variable Selection Process

Both the probit and GLM models from the two-part estimation procedure use a set of independent variables which describe the characteristics of the customers and outage scenarios. The study team will have to determine the actual sets of variables for each model. Out-of-sample testing is a useful procedure for selecting and validating the best econometric model for each customer segment. Using out-of-sample testing, the CIC study team should experiment with different model specifications and estimate each model while withholding 25% of the data from the regression. To select the final model, the team should compare the out-of-sample predicted outage costs from each model with the reported outage costs to see which performs best.

[24] A GLM model specification, which uses maximum likelihood estimation, is more appropriate than OLS for specifying the customer damage function due to the nature of the outage cost data. GLM does not assume a linear relationship between outage cost and the independent variables, but it does assume linear relationship between the transformed outage cost in terms of the link function and the explanatory variables. The link function for the CDF is a log link function, due to the zero-value bound to the left and the long tail to the right.

Sullivan et al. (2009) and Sullivan et al. (2012) report potential explanatory variables including, but not limited to:

- *Interruption attributes*: interruption duration, season, time of day, and day of the week during which the interruption occurs.
- *Customer characteristics:* customer type, customer size, business hours, industry group, multifamily (residential)/multi-tenant (C&I) facility, household family structure, presence of interruption-sensitive equipment, presence of back-up equipment, experienced outage in last 12 months.
- *Environmental attributes:* temperature, humidity, storm frequency and other external/climate conditions.

4.5.3.4 Assessing the Impact of Different Factors on Interruption Cost

The final model relates the mean interruption cost (independent variable) for a particular customer to the set of explanatory (dependent) variables. This is the customer damage function. Stakeholders will likely want to understand the relationship that certain explanatory variables have with mean estimated outage cost. For instance, what is the impact on outage cost if the outage occurs on a weekend as opposed to a weekday? With the log link function of the GLM model, one cannot directly interpret the model coefficient for the "weekend" variable to understand the impact However, one can explore the relationship between the explanatory variables and the outage cost estimates by plugging a series of values into the CDF. For example, one could see the impact to estimated outage cost by changing the value of the "weekend" variable while holding the other predictors constant. Similarly, a valuable analysis for some utilities is to see how outage costs vary by duration, time of day and day of week.

4.5.4 Visualizing Customer Interruption Costs

Visualizations are effective tools for communicating the results of CIC studies and for helping stakeholders understand the impact of the explanatory variables on interruption costs. Figure 4-8 and Figure 4-9 are two such examples and show the residential results of a 2012 PG&E study (Sullivan, et al., 2012). Figure 4-8 shows how the cost per outage event varies by region and by duration. Not surprisingly, the cost per event increases with increasing duration. Figure 4-9 shows the effect on outage cost of onset time and day type (weekend versus weekday). Outage cost estimates for outages occurring at night are the most costly, particularly when they take place during the weekend.

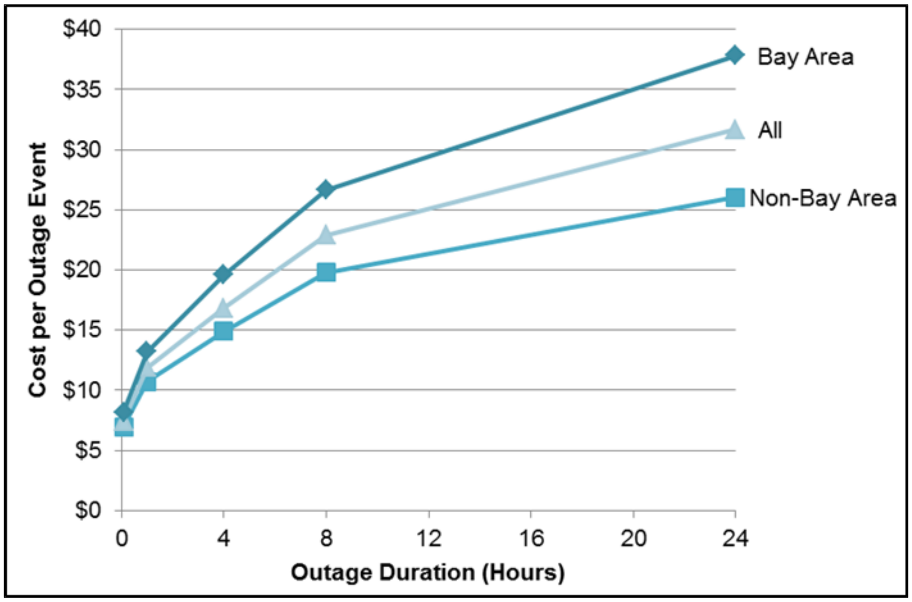

Figure 4-8. Cost per Outage Event Estimates by Region - Residential

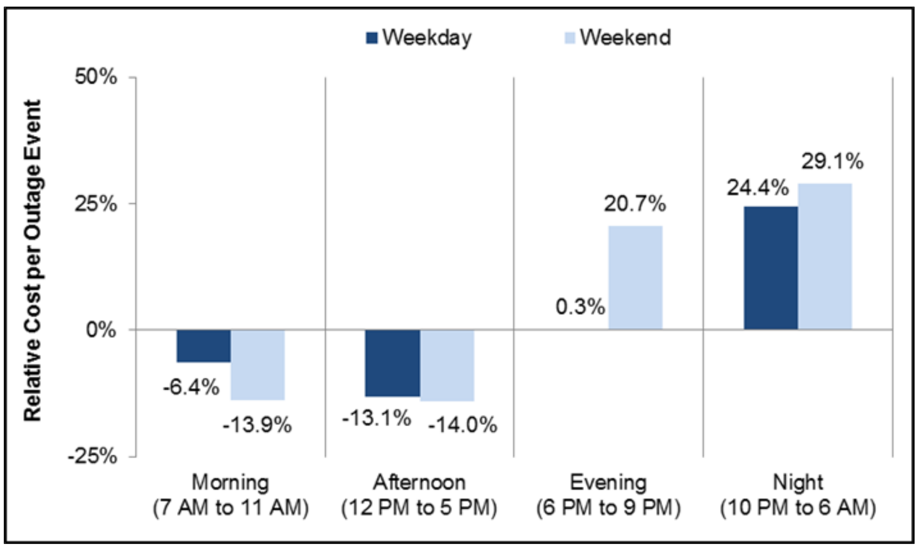

Figure 4-9. Relative Cost per Outage Event Estimates by Day of Week and Onset Time - Residential

4.5.5 Assessing Acceptable Levels of Service Reliability

Each level of service reliability in the survey referred to a specific outage duration and frequency. Figure 4-10, below, shows a useful way to illustrate the relationship between outage frequency, outage duration and customer "acceptability." Frequency is on the x-axis and acceptability on the y-axis. Each curve on the graph represents a different outage duration length. A residential customer's level of service reliability generally becomes less acceptable as outage duration increases and the number of outages per year increases. Figure 4-5 illustrates this finding for the 2012 PG&E study.

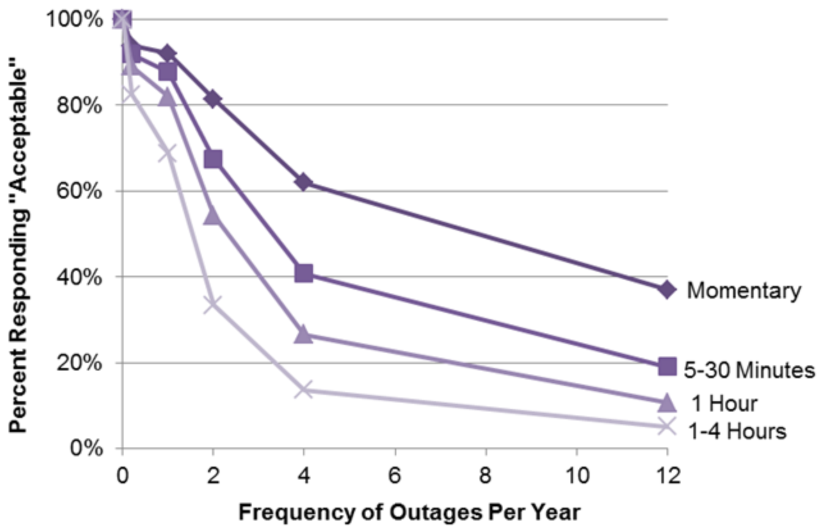

Figure 4-10. Percent of Customers Rating Each Combination of Outage Frequency and Duration as Acceptable - Residential

5. Limitations of CIC Studies

CIC studies are a useful tool for determining the economic value of reliability for value-based planning. However, they do have limitations and it is important to understand the limitations before undertaking the study and using the results. First, properly designed and executed CIC studies can take several months or more to complete. The surveys are relatively complex and respondents must be given enough time to complete them at their convenience. Some C&I customers may need multiple people to be involved in the process of completing forms. Shortening the survey period to meet an internal deadline can attenuate the non-response bias. Past study teams have found that having extra time allows them to follow up with survey recipients.

Second, CIC surveys for residential customers face the same limitations as other stated preference, contingent valuation studies. A critique of WTP studies is that they can overstate WTP. Several decades of study have revealed ways to mitigate this, but nonetheless, it remains a caveat for stated preference studies. WTP surveys can also suffer from anchoring bias. The survey structure can limit this, but fully minimizing it is costly and time consuming. If budget were not a limitation, an in-person interviewer could elicit WTP without revealing the range of possible responses. However, such an approach is expensive and impractical and the tradeoff is accepted for the ability to conduct the study more efficiently. Strategic response can be another source of bias for stated preference studies—particularly for C&I customers, but this can usually be mitigated effectively by breaking direct cost questions down into much smaller components.

Table 5-1 summarizes the main potential sources of bias for CIC studies. The table includes bias specific to WTP and also for CIC studies generally. The "Direction" column indicates how the type of bias tends to affect the CIC estimates. Arrows pointing up mean that the bias will inflate estimates; the reverse applies for arrows pointing down. Sideways arrows indicate that the bias could go up or down, depending on the respondents. The previous sections of this Guidebook discussed each of these sources of bias and how to mitigate them while designing and conducting the study.

Table 5-1. Main Sources of Potential Bias in CIC Studies

Source of Bias	Direction	Description
Hypothetical bias	↑	Results are from stated—not revealed—preferences; respondents may overstate WTP.
Strategic response	↑	Customers (usually non-residential) may purposefully overstate costs to influence study results and subsequent utility investments.
Utility benefit	↓	Respondents show a reluctance to pay additional funds that would go to current utility.
Status quo bias	↓	Respondents favor the "do nothing" option, even when they value improved service.
Anchoring bias	←→	Survey subjects select WTP option based on range of response values offered and not on values themselves.
Survey fatigue	←→	Subjects tire of survey and rush to finish it. They do not take the time to carefully consider responses.
Nonresponse	←→	Systematic differences between customers who completed the survey and those who declined.
Measurement error	←→	Inadequate descriptions of outage scenarios may cause survey subjects to respond inaccurately.

A third limitation of survey-based CIC estimation methods described in this guidebook is that they are most appropriate for outages lasting 24 hours or less. Longer-duration outages can have effects that reach beyond the cost categories contained in the survey forms provided herein. Long duration outages can result in the use of cost mitigation strategies on the part of C&I customers that have impacts on other C&I customers and even for residential customers that are working in those businesses or using their services. For example, to reduce interruption costs, C&I customers may elect to lay off workers for an extended period of time or even close permanently. Depending on their size and geographical scope, C&I customers can also undertake mitigation strategies that significantly reduce costs below the levels they experience in the first 24 hours of interruption by shifting production to facilities not affected by the outage and by cancelling or rescheduling the delivery of feedstocks and plant output. These actions, while limiting outage costs for the affected plant, can impose costs for suppliers and customers that the current survey designs do not capture without further in-depth analysis.

The survey designs provided in this Guidebook are not appropriate for estimating costs of long duration outages in resiliency planning scenarios, because the reactions of customers to outages (and resulting outage costs) are more complex for long duration outages. That is not to say survey based approaches are inappropriate for estimating the costs of long duration outages. Rather, *different* survey based data collection protocols and questions may be necessary to estimate the costs of long duration outages. The industry has very little experience in collecting information about the costs of long duration outages. There has only been one study that applied the survey-based approach to estimating the costs of long duration outages. Sullivan and Schellenberg (2013) examined outages lasting from 24 hours to seven weeks in downtown San Francisco and estimated spillover effects using cost multipliers extracted from a literature review. While this study demonstrated that C&I customers can provide realistic estimates of outage costs for long duration outages, it also revealed the importance of the secondary effects of outages on the economies surrounding the businesses under study. This suggests that future efforts to estimate the costs of long duration outages should include the application of regional economic modeling – perhaps driven by survey data collection efforts designed to collect data on impacts of operations on businesses and employment. However, such an approach requires further development and testing (Sanstad (2016)).

6. Research Frontiers

The following sets of recommendations address opportunities to refine CIC study methods for short-duration outages (24 hours or less) and explore methods for using surveys to estimate costs for longer duration outages. The recommendations for longer duration outages are particularly important and align with a recent report on enhancing resilience from the National Academies of Sciences, Engineering, and Medicine, in which a key recommendation involves "Develop[ing] comprehensive studies to assess the value to customers of improved reliability and resilience…*during large-area, long-duration blackouts*." (National Academies of Sciences, Engineering, and Medicine, 2017).

- **For non-residential customers, advance collaboration between researchers who use survey-based methods and those who develop regional economic models.**

Sanstad (2016) noted that integrating CIC survey data with economic data for regional economic models would facilitate model improvements. Model improvements could include grounding the regional economic models in empirical data on adaptive behavior by firms, which is a current weakness of the models. Using survey data from commercial, industrial and institutional customers as an input to regional economic models may entail adjustments to the survey instrument. Surveys currently obtain economic losses from direct costs of shorter duration outages. Researchers could potentially adapt them to obtain data on indirect costs, as well as information on what a firm expects it would do to adapt behavior during a longer outage. Using the two methods together could speed the development of improved regional economic models, which will be valuable for analyzing resiliency investments to prepare for the increasing frequency of extreme weather events.

- **Incorporate qualitative questions about long-duration outages into traditional CIC studies.**

Researchers and CIC study teams could gain insight into how customers of all classes are prepared to deal with longer duration outages by adding a small number of questions to traditional CIC survey instruments. Long duration outages are not the focus of these studies, so no more than 2-3 questions are necessary. The questions could elicit qualitative information about customers' level of preparation for longer outages and some of the measures they would take to mitigate the impact of not having electricity. These types of questions could also inform the process of designing surveys to estimate long duration outages for future CIC studies.

- **Use ICE Calculator data to test new protocols for sample size and stratification.**

Section 4.2 discussed sample design and recommended stratifying each customer class (or subgroup) by the log of usage, which can serve as a proxy for outage costs. An alternative proxy, which has not yet been thoroughly tested, is the estimated outage cost as calculated by the ICE Calculator's underlying econometric models. These models include the log of usage as one of the independent variables, but contain other independent variables to account for other factors. Researchers could use data from a past study—where measured outage costs are available—to test the effectiveness of using this stratification approach versus using the log of consumption. The procedure would be similar to the simulation approach described in Section 4.2.2. Researchers could also experiment with determining sample size by using the ICE calculator equations. To do so, they would bootstrap—using the ICE calculator equations—to determine the appropriate tradeoff between sample size and standard error.

- **Develop more robust methods for addressing outliers.**

CIC survey results often show a large share of responses indicating that outage costs are zero. The recommended residential survey instrument includes an additional question when a customer responds that WTP is zero to confirm that avoiding an outage is actually worth nothing to that customer. This additional question helps confirm that the response is valid. Similar methods could apply to non-residential customers. Similarly, the authors suggest developing more robust methods for validating extremely high interruption cost estimates for non-residential customers. Validation steps for individual responses should be more standardized to systematically identify outliers that are invalid. In addition, researchers should account for customers that have extremely high outage costs, but are unlikely to experience a complete outage. For example, utilities typically serve their largest key accounts through multiple feeders, in which case it is significantly less likely that the customer will experience a power interruption. If this is the case, it may not be appropriate to apply the outage cost estimates for that customer to standard reliability planning scenarios.

- **Test methods for estimating interruption costs of master-metered buildings.**

Section 4.4.4 discussed sampling tenants from master-metered C&I premises to estimate the cost of the entire building. In the absence of tenant consumption data to design a separate sample, this Guidebook recommended sampling 5 to 10 tenant businesses occupying the master metered premises, as performed in previous studies (Sullivan, et al., 2012). Estimating interruption costs of master-metered buildings is an opportunity for further research. The current practice of soliciting tenants to take surveys takes time, adds complexity, and adds cost to the study. Obtaining 5 to 10 completed surveys requires identifying the businesses at a premise, finding contact information, making phone calls to potentially 50 different tenants, offering incentives, and following up with tenants who do not complete the survey. A possible solution could involve a macro study of high rise buildings to inform all CIC survey implementation plans. An industry-wide study to identify the relationship between energy consumption and tenant costs for high rise buildings could offer a more straightforward means of estimating interruption costs. CIC study teams could leverage the results for their own separate CIC studies through an online tool similar to—or part of—the ICE Calculator.

- **Develop more advanced designs for online survey instruments for residential and small/medium C&I customers.**

Currently, web-based CIC surveys are a relatively straightforward, adequate means for conducting CIC studies. However, the CIC survey instruments do not fully utilize the current capabilities of online surveys. The authors recommend testing new formatting and design and experimenting with ways to make the surveys more interactive. These types of modifications could yield tangible benefits for CIC studies, such as improving the accuracy of estimates and reducing anchoring bias and survey fatigue.

- **Test potential enhancements of residential survey instrument.**

A number of experts in the area of interruption cost estimation and stated preference methods in general have recommended potential modifications to the residential survey instrument, which utilizes the WTP payment card elicitation technique (Shawhan, 2018). They have expressed a wide range of opinions about improvements that could be made to the survey designs contained within the Guidebook. While there is no consensus on the set of modifications that should be made, some may have merit—and should be considered for incorporation into the current survey design in the future. Below is a list of the modifications that have been suggested:

- Be explicit about geographic range of outage (specify that the interruption is limited to the dwelling to avoid residential customers estimating indirect costs).
- Include reminders for residential respondents that they will have less money to spend on other goods if they spend money avoided the interruption.

- Utilize stochastic bid cards, which modify the ranges of WTP values randomly to mitigate anchoring bias.
- Repeat the duration of the outage in the survey valuation questions as an additional reminder of the length of the outage.
- Ask explicitly about how much the household would be willing to pay to avoid confusion between attributing a response to an individual versus the entire household or dwelling.
- Test techniques for reducing hypothetical bias, based on (Loomis, 2014):
    - Urge respondents to be honest and realistic.
    - Ask respondents to sign a truthfulness oath before answering the valuation question(s).
    - Ask the respondents how much they think others would be willing to pay.
    - Communicate the consequentiality of the survey.
- When customers answer that their WTP is $0, the survey asks the follow-up question of whether WTP is actually zero or if there is some other reason for selecting $0. This "other reason" option asks respondents to explain, as opposed to checking a box, which could dissuade them from responding truthfully. Another technique would be to provide a set of discrete answer choices that do not require writing. This could also reduce the need for subjective judgement when analyzing responses.

These modifications should be discussed further and, if appropriate, systematically tested using a combination of cognitive testing, focus groups, and small scale surveys on samples of residential customers.

➢ **Test alternative elicitation methods for residential customers in utility-sponsored CIC studies.**

As Section 3.1.1 mentioned, there is no consensus among experts over the best method for eliciting interruption costs for CIC studies (Larsen et al., 2018). The payment card technique has been used in dozens of CIC studies (for residential customers) and provides the basis for the ICE Calculator meta-database, but there is the potential to both further refine the payment card technique and explore the use of DCE for utility-sponsored studies. There should be a systematic effort to test alternative strategies (including DCE) with the caveat that bit all of these strategies can be employed in the field. DCE surveys could mitigate anchoring bias and would present respondents with choice sets that better resemble an actual choice they would make in purchasing improved reliability. Changing to this survey design format merits serious consideration.

There are several significant challenges in developing DCE survey designs that can be implemented by utilities. Unlike the survey designs that are currently used, the responses to DCE surveys do not directly reveal the costs that customers say they would be willing to pay for a given level of service reliability. Instead, customer interruption costs must be inferred from the responses they give to randomly chosen sets of price and reliability attribute combinations (choice sets). Econometric techniques are employed to estimate the utility functions that customers have for reliability from the pattern in their choices. Without a background in econometrics, it is difficult for end users to understand and believe the outage costs that are obtained from these techniques. Thus, it may be difficult to get practitioners to substitute these more sophisticated measurement techniques for the simpler and more straightforward methods currently in use.

In addition, DCEs surveys may present a somewhat higher cognitive burden on respondents than the current simple willingness to pay questions, so care must be taken to design the survey forms such that respondents remain engaged with the experiment. It is important that respondents not abandon the survey before their responses to all the choices are obtained or worse, fall into a repetitive decision making rule that ignores the complexity of the decision they are facing (i.e., choice based solely on the difference in price).

Finally, there are numerous design details in formulating DCE surveys that should be carefully studied before these techniques are used in CIC surveys. These design details include:

- Whether to use an adaptive conjoint design in which the attributes of the choices are determined for each respondent based on the importance of those attributes to the customer
- Whether to present simple binary choices (accept/decline) or to employ a bounded logit design in which respondents are presented with two stage decisions intended to identify the range of prices within which they would accept the choice set
- Whether to constrain the survey design so that it can be completed by computer or in paper form (to eliminate bias that may result from differences in computer literacy)

Despite the challenges listed above, the authors believe that the development of a standard DCE-based survey design could yield improvements over the existing methodology – eliminating uncertainty about important sources of bias. We recommend that a survey development project be undertaken to design and test alternative survey designs based on DCE. The development effort should commence with a more thorough review of possible measurement designs. Prototype survey instruments should be tested on a small scale to establish the usability of the alternative survey designs.

- **For residential customers, experiment with using non-market valuation methods for outages lasting longer than 24 hours.**

To date, the literature is very limited with regard to using non-market valuation methods to estimate the costs of long duration interruptions (see Sullivan & Schellenberg (2013)). More research should be conducted to test the effectiveness of using surveys to quantify CICs for outages lasting more than 24 hours for residential customers. Researchers could test different adjustments to the residential survey instrument, so that it is more applicable to the situations customers would face with a long duration outage. One challenge will be separating the economic effects of long duration outages from the direct effects of the storm or other events that caused the outage (e.g. separating the economic impact of widespread flooding from the impact of not having electricity). Nonetheless, non-market valuation approaches, including WTP, WTA and choice experiments, could prove to have a broader research application for quantifying, long duration residential CICs with more testing and experimentation.

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Appendix A. **Case Studies**

Case study 1: Generation Planning – ERCOT

Objective

The Public Utility Commission of Texas (PUCT) retained The Brattle Group to estimate the economically optimal reserve margin for the Electricity Reliability Council of Texas' (ERCOT) wholesale market.

Background

A reserve margin is the amount of generating capacity that is available in excess of the average system peak demand. Larger reserve margins mean higher capital costs from constructing more generation plants, coupled with lower costs from supply shortfalls due to shedding load (implementing rotating outages), dispatching demand response and other emergency event costs. Conversely, lower reserve margins mean lower capital costs and higher costs from reliability and emergency events (more rotating outages). At the time of the study, the traditional 1-in-10 (0.1 LOLE[25]) standard translated to a 14.1% reserve margin for ERCOT.

Methodology

The authors of the study performed a series of modeling simulations of ERCOT's system using the Strategic Energy Risk Valuation Model (SERVM). As the report details, "SERVM probabilistically evaluates resource adequacy conditions by simulating ERCOT's generation outages, weather and other load uncertainty, intertie availability, demand-side resources, and other factors." The authors used a Monte Carlo simulation to vary supply and demand conditions over many scenarios. The simulations determined the number and duration of reliability events, emergency events and load shedding events and quantified the economic impacts of load shedding using VOLL (i.e., cost of EUE). The study found the economic implications of alternative reserve margins and performed sensitivity analysis of key parameters, including VOLL. Furthermore, a base case VOLL equal to the High System-Wide Offer Cap of $9,000/MWh was used. Alternatively, researchers could estimate CIC using customer surveys to obtain a VOLL that reflects interruption costs for the study area.

Results

The economically optimal reserve margin is the reserve margin that minimizes total costs. A number of different factors made up total cost for these simulations. Figure A-1 shows the results of the simulations with each vertical bar indicating the components of total cost. The bottom component—"Marginal CC Capital Costs"—represents the costs of building more combined cycle (CC) generating plants. These costs increase with higher reserve margins. "Production Costs" represent the total system production costs (above a $10 billion per year baseline so as not to overwhelm the other components in the graph). These costs decrease with higher reserve margins as production costs are lower for higher-efficiency combined cycle plants, as opposed to natural gas-fired peaking plants (i.e., simple-cycle combustion turbines). The various components in the middle of the bar reflect reliability and

[25] Loss of Load Expectation

emergency supply costs. These costs decrease with increasing reserve margin, as the number of reliability and emergency events decrease. The red portion of the bar graph on the top of the chart shows the costs associated with load shedding, or power interruptions. These costs reflect the VOS, or VOLL for customers.

The simulations found that the economically optimal reserve margin was 10.2%. At this point, total costs are at a minimum, as Figure A-1 illustrates. Increasing the reserve margin beyond this point is not cost effective, as the marginal costs from adding more generation outweigh the cost reductions of the other components. The optimal reserve margin of 10.2% was less than the 1-in-10 LOLE of 14.1%. The authors found this result using a base cost for VOLL of $9,000/MWh, but also performed a sensitivity analysis across a range of values. They found that changing the VOLL from 50% of the base cost value to 200% led to optimal reserve margins ranging from 8.9% to 11.8%.

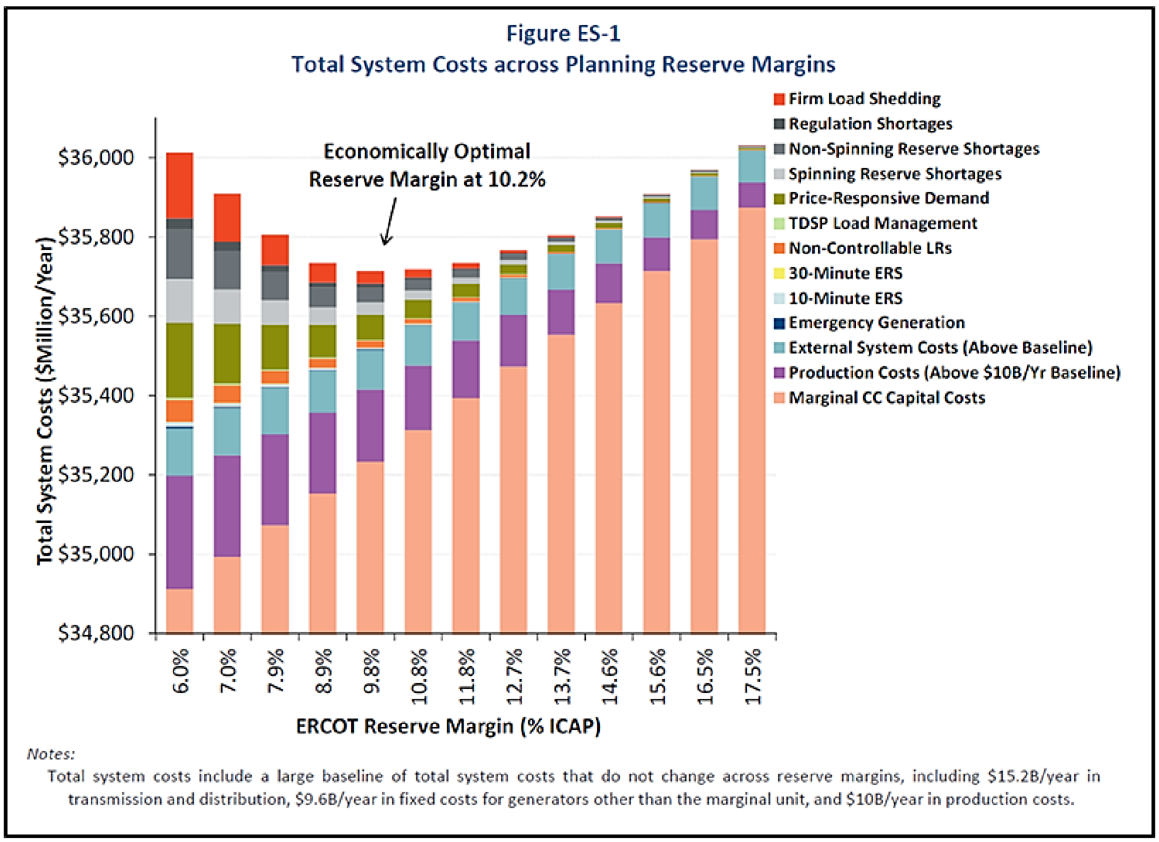


Figure A-1. Total System Costs Across Planning Reserve Margins (from Newell et al., 2014)

Case Study 2: Transmission Upgrade - Puget Sound Electric

Objectives

The objectives of this study were to:

- Determine the extent of customer outages under several worst case equipment outage scenarios

- Simulate the rotating customer outages (rolling blackouts) that would be needed under these scenarios if no action was taken to upgrade the system, and
- Estimate the customer outage costs resulting from the rotating outage scenarios

Background

Puget Sound Energy (PSE) was considering a transmission upgrade for service to its Eastside area in 2015.[26] PSE's most recent planning studies indicated that several contingency scenarios could result in significant customer outages as early as 2018 in the Eastside area if PSE did not upgrade the system. Equipment outages would lead to overloaded transmission power transformers. To prevent the overloads, PSE could implement Corrective Action Plans (CAPs) to open transmission circuits that were normally closed in order to limit the impact of the initial outage. Under certain conditions, the CAPs would be insufficient and PSE would have to interrupt customers' electric service to reduce loading on overloaded transformers. In addition, the CAPs themselves placed certain customers at risk of rotating outages. PSE would most likely limit rotating outages to two hours at a time for each substation to mitigate the impact on customers who lost service. The potential for customer outages also increased over time, given that PSE expected load to grow by 2.4% per year in the Eastside area over the next 10 years. PSE retained Nexant to assess the economic impacts of taking no action to upgrade the system.

Methodology

The study team chose three rotating outage scenarios for this analysis based on a series of load flow studies conducted for summer 2018 and 2024, and winter 2023-2024. These load flow studies were based on the updated Western Electric Coordinating Council (WECC) planning base cases for 2015. The scenarios represented the three worst case scenarios that led to rotating outages:

- Scenario 1: An outage of two transmission substation transformers in the summer of 2018;
- Scenario 2: An outage of two transmission substation transformers in the summer of 2024; and
- Scenario 3: An outage of two transmission substation transformers in the winter of 2023-2024.

Table A-1 provides the results of the rotating customer outage analysis. For Scenario 1 (summer 2018), customers would experience rotating outages on 6 days over a period of 9 days. For Scenario 2 (summer 2024), customers would experience rotating outages on 9 days over a period of 16 days, and customers would experience rotating outages on 13 days over a period of 29 days for Scenario 3 (winter 2023-2024). In these scenarios, the maximum number of substation transformers shedding load in any given hour ranged from 25 to 36 transformers. The total amount of transformer loading relief required was approximately 1,500 MWh in the summer of 2018 and around 3,800 MWh in the summer of 2024 and winter of 2023-2024.

[26] Website: https://energizeeastside.com/

Table A-1. Summary of Rotating Outage Analysis

Results	Scenario 1, Summer 2018	Scenario 2, Summer 2024	Scenario 3, Winter 2023-2024
Number of Days of Load Shedding (Days)	6	9	13
Duration of Load Shedding Period In Days from Start to End (Days)	9	16	29
Maximum Number of Substation Transformers Shedding Load in Any Hour (Count)	25	32	36
Total Amount of Transformer Loading Relief Required (MWh)	1,506	3,864	3,764

Customer interruption cost surveys are the best method for estimating customer outage costs. The primary drawback of this method is that it requires collecting detailed information from large, representative samples of residential, commercial and industrial (C&I) customers. In lieu of conducting a survey, the study team used the econometric models from the 2015 meta-analysis, which underlie the ICE Calculator, to estimate customer interruption costs. It did not directly apply the ICE Calculator due to the complexity of the rotating outage scenarios.

Using the simulated rotating outage scenarios and PSE customer data as inputs, the ICE econometric models produced outage cost estimates for each scenario in the PSE Eastside area. The models incorporated all customer data inputs at the individual customer level for each outage event. The study team defined an outage event as a substation (or set of substations) that lost power for a specific duration on a specific day and time. For example, in one particular outage event, Substation #1 experienced a 1-hour outage during hour 11 on July 9, 2024 (example event day). To estimate the cost for this individual outage event, the model used data for customers served by Substation #1 and then estimated the cost of a 1-hour summer outage during hour 11 for those specific customers, based on the customer class, usage and industry type of each customer. The team summed these disaggregated outage cost estimates at the individual customer level for each outage event and for each scenario. Figure A-2 depicts how the study team used the ICE models and customer data.

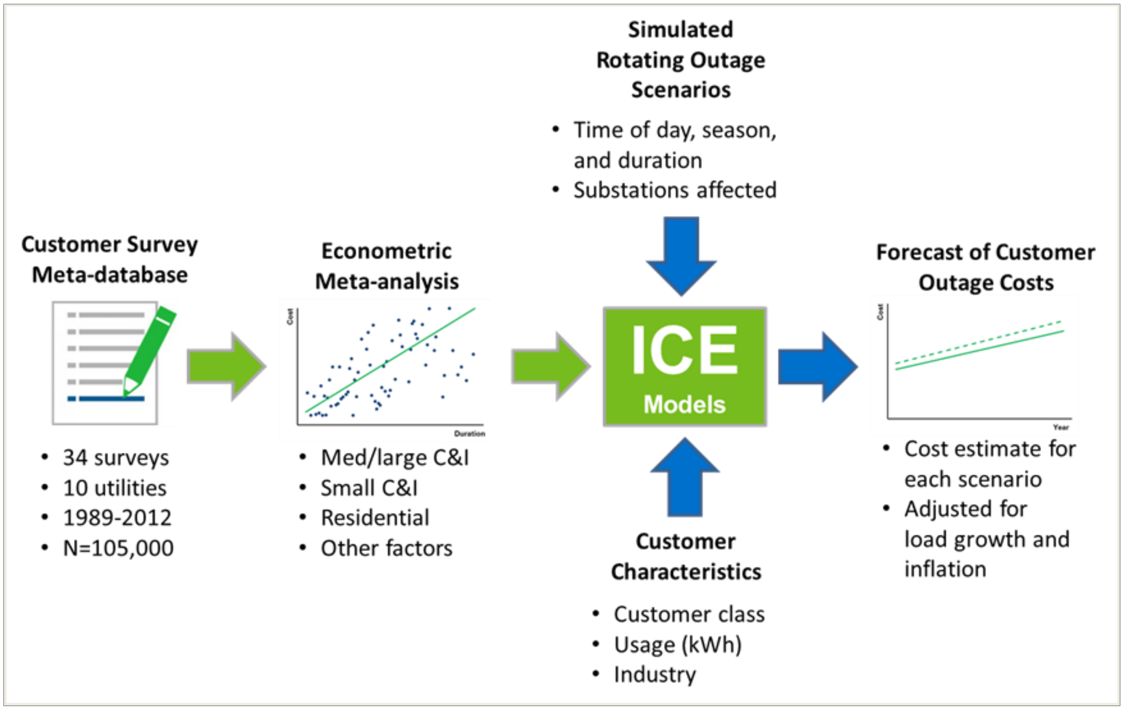


Figure A-2 Framework for Energize Eastside Outage Cost Study

Results

Table A-2 provides a summary of the outage cost analysis. The total customer outage cost resulting from the summer 2018 scenario was $92 million. The total customer outage cost increased to around $275 million in the summer 2024 and winter 2023-2024 scenarios. The increase between the 2018 and 2024 scenarios is primarily due to load growth necessitating more rotating outages. Rotating outages shed nearly 19,000 MWh of customer load in the winter 2023-2024 scenario. The total cost is concentrated in the C&I sectors, given that these customers experience substantially higher direct costs as compared to residential customers. This is typical for CIC surveys.

Table A-2. Summary of Outage Cost Analysis

Scenario	Customer Class	Number of Customers Experiencing Rotating Outages	Total Outage Cost	Customer Load Shed	Cost per Unserved kWh
			$ Millions	MWh	$
Scenario 1, Summer 2018	Medium and Large C&I	2,799	$65.1	2,419	$26.9
	Small C&I	7,983	$23.3	207	$112.5
	Residential	120,213	$3.8	2,093	$1.8
	Scenario 1 Total	**130,995**	**$92.1**	**4,719**	**$19.5**
Scenario 2, Summer 2024	Medium and Large C&I	4,480	$179.3	5,266	$34.0
	Small C&I	14,086	$84.5	577	$146.4
	Residential	192,674	$10.8	4,751	$2.3
	Scenario 2 Total	**211,240**	**$274.6**	**10,594**	**$25.9**
Scenario 3, Winter 2023-2024	Medium and Large C&I	3,142	$153.1	8,897	$17.2
	Small C&I	9,786	$115.7	875	$132.3
	Residential	161,890	$8.1	8,914	$0.9
	Scenario 2 Total	**174,818**	**$276.9**	**18,686**	**$14.8**

Case Study 3: Distribution Modernization - Avangrid

Objective

Estimate the customer value associated with reductions in customer outage minutes from integrating AMI with OMS.

Background

In 2016, two Avangrid subsidiaries—New York State Electric & Gas and Rochester Gas & Electric—proposed implementing AMI as a foundational system for realizing the REV[27] goals of empowering customers through new usage management tools, establishing and animating new markets to promote the implementation of DERs, and minimizing environmental impacts of power generation and energy consumption. Avangrid conducted a benefit/cost analysis (BCA) to evaluate the investments, business process changes and programs enabled by AMI. One such investment was AMI-OMS integration. The benefits were reduced customer outage costs from AMI providing faster visibility into where outages occur and reducing restoration times.

[27] Reforming the Energy Vision. See here for more information: https://rev.ny.gov/

BRIDGE assessed how the integration of AMI with OMS would reduce outage duration. BRIDGE's assessment found that AMI-OMS integration would reduce customer outage minutes in cases where the meters detected the outage (as opposed to cases where telemetry or tripped breakers detected the outage). When a non-telemetered component of the system fails and a utility does not have AMI integrated with OMS, the utility would typically not identify the outage until a customer called. For these types of outages, AMI-OMS integration improves reliability in two ways. First, smart meters send a last gasp message to the OMS system and that message is typically received more quickly than a call from a customer. Second, by analyzing the set of last gasp messages that the OMS received, it can locate the outage using prior knowledge of network connectivity to identify the open device. This reduces the time associated with a crew traveling to a feeder to locate the open device themselves. These operational efficiencies reduce outage duration and, thus, customer outage costs.

The study team made the following assumptions to quantify the benefits of reducing outage durations:

- The time saved before an outage confirmation was 3 minutes, the average time for a customer to call to report an outage; and
- The time saved identifying an open device was 12 minutes at NYSEG and 8 minutes at RG&E (NYSEG tends to have longer feeders).

Methodology

Nexant applied the econometric models from the 2015 meta-analysis of customer outage costs in this analysis of the benefits of AMI-OMS integration (see Sullivan, et al., 2015). Nexant did not use the ICE Calculator itself, because the reliability improvement from AMI-OMS integration applied to specific types of outages (those arising from non-telemetered fuses and breakers).

Nexant received data on every outage that occurred in RG&E's and NYSEG's service territories for the years 2013 through 2015. This database contained key attributes of each outage, including date and time of the occurrence, outage duration, the feeder it occurred on, the number of customers affected by type, and the equipment that triggered the outage. To model the effect of AMI-OMS integration, Nexant identified outages caused by tripping a non-telemetered fuse or breaker and lasting longer than 3 minutes. These were the types of outages from which Avangrid would realize benefits from AMI-OMS integration.

Nexant reduced the duration of each relevant outage based on BRIDGE's assessment. It combined this information with estimates of outage costs from the econometric models. The estimates reflected the customer mix on the feeder where the outage occurred, as well as the time of day, season, and duration of the outage. The result was two cost estimates for every historical outage: one for the actual outage and another for the outage assuming the duration was reduced due to AMI. The sum of the costs yielded aggregate values for each year with and without AMI-OMS integration, the difference of which is the aggregate annual benefit associated with AMI-OMS integration.

Results

Table A-3 summarizes the annual benefit (in 2016 dollars) of AMI-OMS integration for each year of historical outages from 2013 through 2015 for each utility, assuming AMI is fully deployed. On average, NYSEG benefits from avoided customer outage costs equal $5.25 million per year, and RG&E customer benefits equal nearly $1.1 million per year. The average avoided cost per reduced customer outage minute is similar for each utility ($0.78 for NYSEG and $0.75 for RG&E).

Table A-3. Aggregate Benefit of AMI-OMS Avoided Outage Costs ($ Millions)

Utility	Year	Outages of Non-telemetered Fuses and Breakers	Average Number of Customers per Outage	Benefits of AMI-OMS Integration		
				Reduced Customer Outage Minutes	Avoided Customer Outage Costs	Avoided Cost per Reduced Customer Minute (2016 $)
NYSEG	2013	10,748	51	8,287,755	$5.6	$0.68
	2014	11,029	38	6,304,095	$5.5	$0.87
	2015	9,990	37	5,585,865	$4.7	$0.83
	Average	**10,589**	**42**	**6,725,905**	**$5.3**	**$0.78**
RG&E	2013	3,235	45	1,592,811	$1.2	$0.75
	2014	2,951	42	1,367,047	$1.0	$0.75
	2015	2,947	42	1,372,338	$1.0	$0.76
	Average	**3,044**	**43**	**1,444,069**	**$1.1**	**$0.75**

The present value of the avoided customer outage cost benefit due to AMI-OMS integration was roughly $62.7 million for NYSEG and $11.5 million for RG&E, for a total benefit of $74.2 million across the two companies. Figure A-3 summarizes the quantifiable societal costs and benefits associated with AMI deployment. All values in the figure are in present value terms from 2018 (when deployment would begin) through 2040 (when the last installed meters would reach their assumed 20-year life), expressed in 2016 dollars. The cost of AMI-OMS integration was already included in the $114 million in IT hardware and software costs.

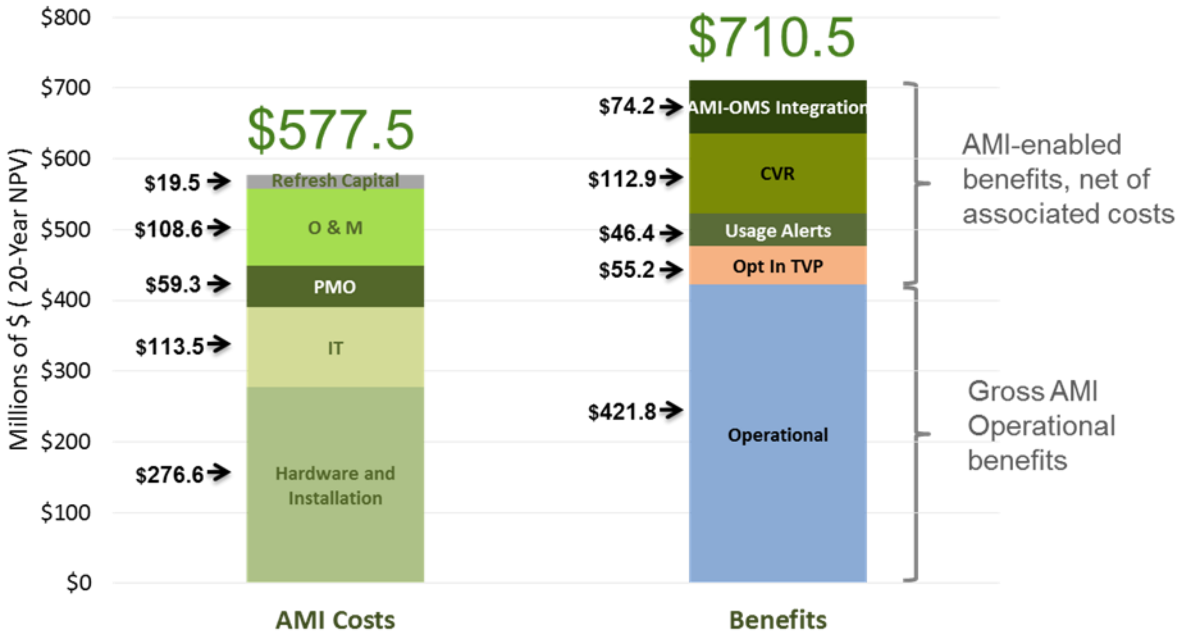


Figure A-3. Present Value of Societal Costs and Benefits

The BCA estimated the quantifiable societal benefits of full deployment of AMI in RG&E and NYSEG to exceed the present value of costs by almost $133 million over the assumed life of the investment. With a societal benefit-cost ratio of over 1.2 and the fact that the analysis did not include many intangible and hard-to-forecast benefits such as market animation and increased penetration of DERs, Avangrid concluded that full deployment of AMI was a sound decision.

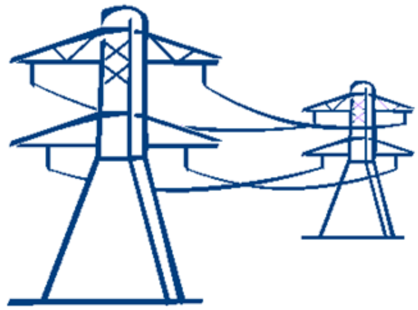
Appendix B. **Residential Survey Instrument**

This appendix contains the residential survey instrument from a distribution planning study. The survey was customized to serve the purpose of the utility undertaking the study. The survey instrument includes variation in seasonality instead of variation in day of week (weekend vs. weekday). Fields enclosed in double brackets (<< >>) indicate fields for a mail merge.

This survey instrument is a guide and the study team can modify questions or descriptions at its discretion to add clarity. However, study teams should exercise caution when making significant changes to the format or content of the interruption cost survey so as not to introduce bias. In addition, if the study team wants to compare results to those of past studies, it should not make major changes to the instrument.

Utility
Value of Service Study

Residential Customers



Dear [Full Name of Customer],

You may recall receiving a letter from [Utility] within the past few weeks, encouraging you to complete a short online survey. It contained a $[Incentive Amount] as a token of our appreciation for completing the survey. Remember that all of your answers will be confidential. Your name and address will be kept anonymous and will not be associated with the information you provide.

As of the time this letter was printed, we have not received your input. For your convenience, we have enclosed a paper copy of the survey. Completing the survey will only take a few minutes of your time. The survey is still available online should you prefer to complete it electronically.

To complete the survey online, go to: **[website]**

Your survey ID is: **«id»**

We thank you in advance for participating in this important survey! Please note that we are only interested in your residence at the address below:

<< SERVICE_ADDRESS >>

If you share a building with other owners or tenants, please answer the questions **only about your residence**.

Thank you in advance for your participation in this valuable study. If you have already completed the survey, thank you and please disregard this letter. If you have any questions, please call us at [Phone Number] ([Days and Times Available]).

Sincerely,

SIGNATURE IMAGE

Name
Utility Contact Name
Utility Position
Utility

When completing this survey, please note that a "power outage" refers to a complete loss of electricity to your residence. Power outages can be caused by many factors such as bad weather, traffic accidents, and equipment failures.

1. In the **past 12 months**, about how many outages of the durations listed below have you had at your home? Write in the number of outages on the blanks. (If none, use "0".)

   ________ A short duration (one minute or less)
   ________ Longer than one minute and up to 1/2 hour
   ________ Longer than 1/2 hour and up to 1 hour
   ________ Longer than 1 hour and up to 4 hours
   ________ Longer than 4 hours and up to 24 hours
   ________ Over 24 hours

2. Do you feel that the number of power outages your residence experiences is…
   - ☐ Very low
   - ☐ Low
   - ☐ Moderate
   - ☐ High
   - ☐ Very high

3. How satisfied are you with the reliability of the electrical service you receive from [Utility]?
   - ☐ Very dissatisfied
   - ☐ Somewhat dissatisfied
   - ☐ Neither satisfied or dissatisfied
   - ☐ Somewhat satisfied
   - ☐ Very satisfied
   - ☐ Don't know

4. Do you or any of your household members work at home most of the time?
   - ☐ No
   - ☐ Yes -- What kind of business is it? ____

   4a. How are you compensated for the work you perform at home?
   - ☐ Self-employed
   - ☐ Salary from employer
   - ☐ Hourly wage from employer

5. Do you or does anyone in your household have any health conditions for whom a power outage could be a significant problem?
   - ☐ No
   - ☐ Yes – Please explain: ____

Next, we will ask you about 6 different types of electrical power outages. For each type of outage we would first like to know how you and your household would adjust to the outage. Second, we would like you to estimate the extra expenses that your household would experience as a result of this type of outage as well as the estimated cost of inconvenience or hassle. Some of the expenses and inconveniences that people might experience include using candles if it is dark, going out to eat if you cannot cook, food spoiling, etc.

Because every person may feel differently about the amount of extra expenses and the inconvenience or hassle, there are no right or wrong answers to these questions. We simply want your honest opinion.

IMPORTANT

As you answer the questions, please remember these two definitions:

Inconvenience or hassle costs
When a power outage occurs, a household may experience inconvenience or hassle costs while adjusting to the outage. Among others, these may include having to use candles if it is dark, having to dine out, not being able to watch television or not being able to use the internet.

Note: If you have solar photovoltaic (PV) panels installed, your household will still experience the power outage and your PV system will not feed electricity into the grid.

Extra expenses
These may include food spoilage, dining out or lost wages for lost work time due to outages. In adding up your extra expenses, please do **<u>not</u>** include expenses that your household would have incurred whether or not the power outage happened. For example, if you decided to dine out during the outage **<u>instead of</u>** another night, the cost of the dinner should **<u>not</u>** be considered as an extra expense because it is simply shifted from another night. However, if you had to dine out during the outage **<u>in addition to</u>** another night, the cost of the dinner should be considered an extra expense.

Case A:
On a <<SEASON1>> weekday, a complete power outage occurs at <<ONSET>> without any warning. You do not know how long it will last, but after 4 hours your household's electricity is fully restored. Note that **all** of the remaining cases occur at **<<ONSET>>**.

SUMMARY:
Conditions: <<SEASON1>> weekday **Start time:** <<ONSET>>
Duration: 4 hours **End time:** <<END1>>

A1. Since you would not know beforehand when the outage would occur or how long it would last, how would your household adjust during and after this outage? (Check all that apply.)

- ☐ There is generally no one home on a <<SEASON1>> weekday at this time
- ☐ Stay home and do activities that don't require electricity
- ☐ Go out and eat, shop or visit friends
- ☐ Run a backup power generator
- ☐ Use a propane/gas stove or grill for cooking
- ☐ Reset clocks and appliances after outage
- ☐ Other (please describe) ____

A2. How much do you think it would cost your household in extra expenses **and** in inconvenience or hassle to adjust to this outage? If necessary, please refer to the definitions on page 2.

$ ________ extra expenses **and** inconvenience costs

A3. Of the above amount, how much of it would be **just for the extra expenses**?

$ ________ extra expenses **only**

A4. Suppose a company (other than [Utility]) could provide you with a temporary backup power service to handle all of your household's electricity needs during this particular outage. With this backup service, you would not experience the outage and would not have to make any adjustments.

Please indicate the one-time amount you would be willing to pay for this temporary backup service to avoid this particular outage. *(Please circle or specify one amount.)*

$0 $1 $3 $5 $7 $10 $12 $15 $20 $25 $30 $40 $50 $75 $100

Other (please specify) $_________

A4a. **If you circled $0 in question A4**, is that because the service is really worth nothing to you or is there some other reason? (Check one)

- ☐ Worth nothing
- ☐ Other reason (please explain)

____

____

Case B:
On a <<SEASON1>> weekday, a complete power outage occurs at <<ONSET>> without any warning. You do not know how long it will last, but after 1 minute your household's electricity is fully restored.

SUMMARY:

Conditions:	<<SEASON1>> weekday	**Start time:**	<<ONSET>>
Duration:	1 minute	**End time:**	<<END2>>

B1. Since you would not know beforehand when the outage would occur or how long it would last, how would your household adjust during and after this outage? (Check all that apply.)

- ☐ There is generally no one home on a <<SEASON1>> weekday at this time
- ☐ Stay home and do activities that don't require electricity
- ☐ Go out and eat, shop or visit friends
- ☐ Run a backup power generator
- ☐ Use a propane/gas stove or grill for cooking
- ☐ Reset clocks and appliances after outage
- ☐ Other (please describe) ____

B2. How much do you think it would cost your household in extra expenses **and** in inconvenience or hassle to adjust to this outage? If necessary, please refer to the definitions on page 2.

$ ________ extra expenses **and** inconvenience costs

B3. Of the above amount, how much of it would be **just for the extra expenses**?

$ ________ extra expenses **only**

B4. Suppose a company (other than [Utility]) could provide you with a temporary backup power service to handle all of your household's electricity needs during this particular outage. With this backup service, you would not experience the outage and would not have to make any adjustments.

Please indicate the one-time amount you would be willing to pay for this temporary backup service to avoid this particular outage. *(Please circle or specify one amount.)*

$0 $1 $3 $5 $7 $10 $12 $15 $20 $25 $30 $40 $50 $75 $100

Other (please specify) $_________

B4a. **If you circled $0 in question B4**, is that because the service is really worth nothing to you or is there some other reason? (Check one)

- ☐ Worth nothing
- ☐ Other reason (please explain)

____

____

Case C:
On a <<SEASON1>> weekday, a complete power outage occurs at <<ONSET>> without any warning. You do not know how long it will last, but after 1 hour your household's electricity is fully restored.

SUMMARY:

Conditions:	<<SEASON1>> weekday	**Start time:**	<<ONSET>>
Duration:	1 hour	**End time:**	<<END3>>

C1. Since you would not know beforehand when the outage would occur or how long it would last, how would your household adjust during and after this outage? (Check all that apply.)

- ☐ There is generally no one home on a <<SEASON1>> weekday at this time
- ☐ Stay home and do activities that don't require electricity
- ☐ Go out and eat, shop or visit friends
- ☐ Run a backup power generator
- ☐ Use a propane/gas stove or grill for cooking
- ☐ Reset clocks and appliances after outage
- ☐ Other (please describe) ______________________________

C2. How much do you think it would cost your household in extra expenses **and** in inconvenience or hassle to adjust to this outage? If necessary, please refer to the definitions on page 2.

$ ______ extra expenses **and** inconvenience costs

C3. Of the above amount, how much of it would be **just for the extra expenses**?

$ ______ extra expenses **only**

C4. Suppose a company (other than [Utility]) could provide you with a temporary backup power service to handle all of your household's electricity needs during this particular outage. With this backup service, you would not experience the outage and would not have to make any adjustments.

Please indicate the one-time amount you would be willing to pay for this temporary backup service to avoid this particular outage. *(Please circle or specify one amount.)*

$0 $1 $3 $5 $7 $10 $12 $15 $20 $25 $30 $40 $50 $75 $100

Other (please specify) $_________

C4a. **If you circled $0 in question C4**, is that because the service is really worth nothing to you or is there some other reason? (Check one)

- ☐ Worth nothing
- ☐ Other reason (please explain)

____

____

Case D:
On a <<SEASON1>> weekday, a complete power outage occurs at <<ONSET>> without any warning. You do not know how long it will last, but after 8 hours your household's electricity is fully restored.

SUMMARY:

Conditions:	<<SEASON1>> weekday	**Start time:**	<<ONSET>>
Duration:	8 hours	**End time:**	<<END4>>

D1. Since you would not know beforehand when the outage would occur or how long it would last, how would your household adjust during and after this outage? (Check all that apply.)

- ☐ There is generally no one home on a <<SEASON1>> weekday at this time
- ☐ Stay home and do activities that don't require electricity
- ☐ Go out and eat, shop or visit friends
- ☐ Run a backup power generator
- ☐ Use a propane/gas stove or grill for cooking
- ☐ Reset clocks and appliances after outage
- ☐ Other (please describe)

D2. How much do you think it would cost your household in extra expenses **and** in inconvenience or hassle to adjust to this outage? If necessary, please refer to the definitions on page 2.

$ ______ extra expenses **and** inconvenience costs

D3. Of the above amount, how much of it would be **just for the extra expenses**?

$ ______ extra expenses **only**

D4. Suppose a company (other than [Utility]) could provide you with a temporary backup power service to handle all of your household's electricity needs during this particular outage. With this backup service, you would not experience the outage and would not have to make any adjustments.

Please indicate the one-time amount you would be willing to pay for this temporary backup service to avoid this particular outage. *(Please circle or specify one amount.)*

$0 $1 $3 $5 $7 $10 $12 $15 $20 $25 $30 $40 $50 $75 $100

Other (please specify) $_________

D4a. **If you circled $0 in question D4**, is that because the service is really worth nothing to you or is there some other reason? (Check one)

- ☐ Worth nothing
- ☐ Other reason (please explain)

____

____

Case E:
On a <<SEASON1>> weekday, a complete power outage occurs at <<ONSET>> without any warning. You do not know how long it will last, but after 24 hours your household's electricity is fully restored.

SUMMARY:

Conditions:	<<SEASON1>> weekday	**Start time:**	<<ONSET>>
Duration:	24 hours	**End time:**	<<END5>>

E1. Since you would not know beforehand when the outage would occur or how long it would last, how would your household adjust during and after this outage? (Check all that apply.)

- ☐ There is generally no one home on a <<SEASON1>> weekday at this time
- ☐ Stay home and do activities that don't require electricity
- ☐ Go out and eat, shop or visit friends
- ☐ Run a backup power generator
- ☐ Use a propane/gas stove or grill for cooking
- ☐ Reset clocks and appliances after outage
- ☐ Other (please describe) ____

E2. How much do you think it would cost your household in extra expenses **<u>and</u>** in inconvenience or hassle to adjust to this outage? If necessary, please refer to the definitions on page 2.

$ ________ extra expenses **<u>and</u>** inconvenience costs

E3. Of the above amount, how much of it would be **just for the extra expenses**?

$ ________ extra expenses **<u>only</u>**

E4. Suppose a company (other than [Utility]) could provide you with a temporary backup power service to handle all of your household's electricity needs during this particular outage. With this backup service, you would not experience the outage and would not have to make any adjustments.

Please indicate the one-time amount you would be willing to pay for this temporary backup service to avoid this particular outage. *(Please circle or specify one amount.)*

$0 $1 $3 $5 $7 $10 $12 $15 $20 $25 $30 $40 $50 $75 $100

Other (please specify) $_________

E4a. **If you circled $0 in question E4**, is that because the service is really worth nothing to you or is there some other reason? (Check one)

- ☐ Worth nothing
- ☐ Other reason (please explain)

____

____

Case F:
On a <<SEASON2>> weekday, a complete power outage occurs at <<ONSET>> without any warning. You do not know how long it will last, but after 4 hours your household's electricity is fully restored.

SUMMARY:

Conditions:	<<SEASON2>> weekend	**Start time:**	<<ONSET>>
Duration:	4 hours	**End time:**	<<END6>>

F1. Since you would not know beforehand when the outage would occur or how long it would last, how would your household adjust during and after this outage? (Check all that apply.)

- ☐ There is generally no one home on a <<SEASON2>> weekend at this time
- ☐ Stay home and do activities that don't require electricity
- ☐ Go out and eat, shop or visit friends
- ☐ Run a backup power generator
- ☐ Use a propane/gas stove or grill for cooking
- ☐ Reset clocks and appliances after outage
- ☐ Other (please describe) ____

F2. How much do you think it would cost your household in extra expenses **and** in inconvenience or hassle to adjust to this outage? If necessary, please refer to the definitions on page 2.

$ ______ extra expenses **and** inconvenience costs

F3. Of the above amount, how much of it would be **just for the extra expenses**?

$ ______ extra expenses **only**

F4. Suppose a company (other than [Utility]) could provide you with a temporary backup power service to handle all of your household's electricity needs during this particular outage. With this backup service, you would not experience the outage and would not have to make any adjustments.

Please indicate the one-time amount you would be willing to pay for this temporary backup service to avoid this particular outage. *(Please circle or specify one amount.)*

$0 $1 $3 $5 $7 $10 $12 $15 $20 $25 $30 $40 $50 $75 $100

Other (please specify) $_________

F4a. **If you circled $0 in question F4**, is that because the service is really worth nothing to you or is there some other reason? (Check one)

- ☐ Worth nothing
- ☐ Other reason (please explain)

____

____

ACCEPTABLE LEVEL OF RELIABILITY

[Utility] works hard to prevent power outages, but eliminating all outages would be very costly, if not impossible. The following questions help us understand what you consider an acceptable level of service reliability from [Utility].

If each of the following occurred, would you think you were getting an acceptable or unacceptable level of service reliability?

6. An outage lasting **1 minute or less**... (Check one box on each line.)

	Acceptable	Unacceptable	Don't Know
Once a week	☐	☐	☐
Once a month	☐	☐	☐
Once every 3 months	☐	☐	☐
Once every 6 months	☐	☐	☐
Once a year	☐	☐	☐
Once every 5 years	☐	☐	☐

7. An outage lasting between **1 minute and 30 minutes**... (Check one box on each line.)

	Acceptable	Unacceptable	Don't Know
Once a week	☐	☐	☐
Once a month	☐	☐	☐
Once every 3 months	☐	☐	☐
Once every 6 months	☐	☐	☐
Once a year	☐	☐	☐
Once every 5 years	☐	☐	☐

8. An outage lasting **about an hour**... (Check one box on each line.)

	Acceptable	Unacceptable	Don't Know
Once a week	☐	☐	☐
Once a month	☐	☐	☐
Once every 3 months	☐	☐	☐
Once every 6 months	☐	☐	☐
Once a year	☐	☐	☐
Once every 5 years	☐	☐	☐

9. An outage lasting between **1 hour and 4 hours**... (Check one box on each line.)

	Acceptable	Unacceptable	Don't Know
Once a week	☐	☐	☐
Once a month	☐	☐	☐
Once every 3 months	☐	☐	☐
Once every 6 months	☐	☐	☐
Once a year	☐	☐	☐
Once every 5 years	☐	☐	☐

To better understand how electrical power outages affect your household, we would like to gather some information on your household characteristics. Please answer the questions to the best of your ability. If you live in an apartment building or duplex, answer only for the part of the building you actually live in.

Some background information about the people living in your household will also help us understand how electrical power outages would affect your household. Again, all of your answers are *confidential*. Your name and address will be kept anonymous and will not be associated with the information you provide.

10. What type of residence is this? Please check one.

- ☐ Single family house (house on separate lot)
- ☐ Row or townhouse (walls adjacent to another house)
- ☐ A unit in a multi-family structure, 2-4 attached units (example: duplex, triplex, fourplex, or single family house converted to flats)
- ☐ A unit in a large multiple family structure, 5 or more attached units (example: apartment house, high rise condominium, garden apartments)
- ☐ Mobile home, house trailer
- ☐ Other (please describe) ____

11. Do you own or rent your residence?

☐ Own ☐ Rent/Lease ☐ Other (specify) ______________________

12. How many years have you lived at this address? (If less than 1 year, write "0".)

_______Years

13. Which of the following best describes your household? Please choose one.

- ☐ Individual living alone
- ☐ Single head of household with children at home
- ☐ Couple with children at home
- ☐ Couple without children at home
- ☐ Unrelated individuals sharing a residence
- ☐ Other (please describe) ____

14. In approximately what year was this residence built? ________

15. What is the size of your residence? ________square feet

16. How many people, **including yourself**, live in your home? ________

17. Please indicate the number of individuals in your household who are in each of these age groups.

_______ Under 6	_______ 25 to 34	_______ 55 to 59
_______ 6 to 18	_______ 35 to 44	_______ 60 to 64
19 to 24	45 to 54	65 or over

18. Which one of the following age groups best describes your age?

☐ Under 25 ☐ 25 to 44 ☐ 45 to 64 ☐ 65 or over

19. Which of the following categories best describes your total household income during [Year] before taxes and other deductions? Please include all income to the household including social security, interest, welfare payments, child support, etc.

☐ 0 - $9,999	☐ $20,000 - $29,999	☐ $50,000 - $74,999
☐ $10,000 - $14,999	☐ $30,000 - $39,999	☐ $75,000 - $99,999
☐ $15,000 - $19,999	☐ $40,000 - $49,999	☐ $100,000 or more

20. Do you own an electric vehicle?

☐ Yes ☐ No

Please share any additional comments:

Please be sure to return your completed survey.
Thank you!

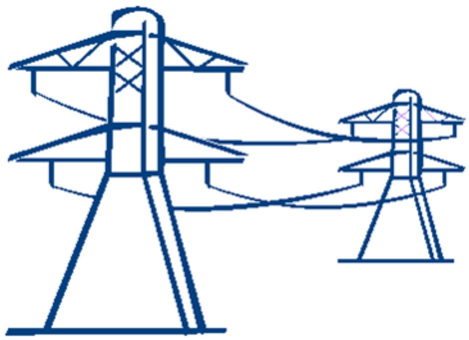
Appendix C. Small & Medium C&I Survey Instrument

This appendix contains the small and medium C&I survey instrument from a distribution planning study. The survey was customized to serve the purpose of the utility undertaking the study. The survey instrument includes variation in seasonality instead of variation in day of week (weekend vs. weekday). Fields enclosed in double brackets (<< >>) indicate fields for a mail merge.

This survey instrument is a guide and the study team can modify questions or descriptions at its discretion to add clarity. However, study teams should exercise caution when making significant changes to the format or content of the interruption cost survey so as not to introduce bias. In addition, if the study team wants to compare results to those of past studies, it should not make major changes to the instrument.

Utility
Value of Service Study

Business Customers



Dear Customer,

Thank you for agreeing to participate in this important study. We are asking you to fill out this survey thinking only about the facilities that your company occupies **at this location:**

«seraddr», «seraddr2»
«sercity»

If your company shares a building with other businesses or you are the property manager at the above address(es), please answer the questions **only for the space your company occupies at this location and the activities your company undertakes**.

All your answers will be kept confidential. Your name and your company's name and address will be kept anonymous and will not be associated with the information you provide.

Please return your completed survey in the enclosed return envelope to receive your $50 check. If you have any questions, please call us at [Phone Number] ([Days and Times Available]).

Sincerely,

SIGNATURE IMAGE

[Utility] Contact Name
[Utility] Position
[Utility]

This survey is also available online at: **[website]**
Your survey ID is **«ID»**

When completing this survey, please note that a “power outage” refers to a complete loss of electricity to your facility. Power outages can be caused by many factors, such as bad weather, traffic accidents, and equipment failures.

1. In the **past 12 months**, about how many outages of the durations listed below have you had at your business location? Write in the number of outages on the blanks. (Use “0” if none.)

   A) Short duration or momentary (one minute or less) _______
   B) Longer than one minute and up to 1/2 hour _______
   C) Longer than 1/2 hour and up to 1 hour _______
   D) Longer than 1 hour and up to 4 hours _______
   E) Longer than 4 hours and up to 24 hours _______
   F) Over 24 hours _______

2. In general, how disruptive have these outages been for your company? (Please check one number.)

❑	❑	❑	❑	❑	❑	❑
1	2	3	4	5	6	7
Not at all disruptive						Very disruptive

3. Has your company ever sent employees home during a power outage?

   ❑1 No
   ❑2 Yes

4. In general, how long can an outage last at your facility before the costs become significant? Please estimate that time length in minutes and/or hours:

   __________ **Hours and** __________ **Minutes**

5. How much advance warning of a power outage does your company need to significantly reduce the problems caused by a power outage?

- ❑1 Advance notice would not reduce problem(s)
- ❑2 At least 1 hour
- ❑3 At least 4 hours
- ❑4 At least 8 hours
- ❑5 At least 24 hours

How satisfied are you with… (Please check one number.)	**Extremely Dissatisfied**						**Extremely Satisfied**
6. The reliability of the electrical service your company has experienced in the **last 12 months**?	❑ 1	❑ 2	❑ 3	❑ 4	❑ 5	❑ 6	❑ 7
7. The length of time it usually takes to restore service after an outage?	❑ 1	❑ 2	❑ 3	❑ 4	❑ 5	❑ 6	❑ 7
8. The responsiveness of [Utility] when you have a power outage?	❑ 1	❑ 2	❑ 3	❑ 4	❑ 5	❑ 6	❑ 7

The next section describes **six** different types of power outages. We would like to know the **costs to your business** of adjusting to each of these power outages.

For many businesses, the costs of a power outage depend upon the particular situation, and **may vary** from day to day depending upon business conditions. So for each outage type you will be given the opportunity to report the **range of outage costs** that your business might face (from low to high), as well as to estimate **the cost that you would most likely have** under typical circumstances.

It is important to try to answer all of the questions. If a question is difficult for you to answer, **please give us an estimate** and feel free to **write down any comments about your answer**.

Case 1:
On a «SEASON1» weekday, a complete power outage occurs at «ONSET» without any warning. You do not know how long it will last, but after 4 hours your company's electricity is fully restored.

SUMMARY:

Conditions:	«SEASON1» weekday	**Start time:**	«ONSET»
Duration:	4 hours	**End time:**	«END1»

9. How disruptive would this power outage be to your business?
(Please check one number.)

❑	❑	❑	❑	❑	❑	❑
1	2	3	4	5	6	7
Not disruptive at all						Very disruptive

10. Would your operations or services typically stop or slow down as a result of this power outage? (If yes, please state the number of hours.)

❑1 No**--------------------->** SKIP TO CASE 2 ON PAGE 6

❑2 Yes**-------------------->**__________ Number of hours that operations or services would stop or slow down (include time **during and after** the power outage)

11. What is the approximate dollar value of the operations or services that typically would be lost, at least temporarily, during the power outage and any slow period after the power outage? (If you are not sure please make your best guess.)

$___________ value of lost work or services

12. What percent of the operations or services typically would be made up after the power outage? (Please check one number.)

❑	❑	❑	❑	❑	❑	❑	❑	❑	❑	❑
0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%

13. Would there be **labor costs** associated with this power outage such as salaries and wages to staff who would be unable to work or overtime pay to make up for operations or services? (If yes, please state the cost for lost labor as well as the cost for overtime labor to make up for lost work.)

❑1 No

❑2 Yes -->$_______labor costs of staff unable to work during the power outage

$_______labor costs in overtime/extra shifts to make up lost work

14. Would there be any **damage costs** associated with this power outage such as damage to equipment, materials, etc.? (If yes, please state how much the damage cost for equipment would be and how much the damage cost to materials would be.)

❑1 No

❑2 Yes --->$_______damage to equipment

$_______damage to materials

15. Would there be **additional tangible costs** associated with this power outage (such as extra restart costs, and costs to run and/or rent backup equipment during the outage)? (If yes, please state the additional costs.)

❑1 No

❑2 Yes --->$_______additional tangible costs

16. If you had to put a dollar value on **intangible costs** due to this power outage (such as inconvenience or dissatisfied customers), what would these costs be? (If yes, please state the intangible cost.)

❑1 No, there would be $0 intangible costs

❑2 Yes, there would be $_______ intangible costs

17. In addition to the costs discussed above, some organizations may avoid business expenses because of electrical outages. Some examples include a lower electrical bill, lower material outlays, and lower personnel costs. Would you experience any savings associated with this power outage? (If yes, please state the savings.)

❑1 No

❑2 Yes --->$_______savings

18. Considering **all** of the costs you might experience as a result of this **4-hour «SEASON1» weekday outage beginning at «ONSET»**, please estimate the total costs for an assumed "Best Case" scenario, the cost for a "Typical Case" scenario and the cost for a "Worst Case" scenario. Please enter zero if there are no costs.

$__________	**$**__________	**$**__________
Lowest Total Outage Cost **(Best Case)**	Most Likely Total Outage Cost **(Typical Case)**	Highest Total Outage Cost **(Worst Case)**

Case 2:
On a «SEASON1» weekday, a complete power outage occurs at «ONSET» without any warning. You do not know how long it will last, but after 1 minute your company's electricity is fully restored. Note that **all** of the remaining cases occur at **«ONSET».**

SUMMARY:

Conditions:	«SEASON1» weekday	**Start time:**	«ONSET»
Duration:	1 minute	**End time:**	«END2»

19. Considering **all** of the costs you might experience as a result of this **<u>1-minute «SEASON1» weekday outage beginning at «ONSET»</u>**, please estimate the total costs for an assumed "Best Case" scenario, the cost for a "Typical Case" scenario and the cost for a "Worst Case" scenario. Please enter zero if there are no costs.

$__________	**$**__________	**$**__________
Lowest Total Outage Cost **(Best Case)**	Most Likely Total Outage Cost **(Typical Case)**	Highest Total Outage Cost **(Worst Case)**

Case 3:
On a «SEASON1» weekday, a complete power outage occurs at «ONSET» without any warning. You do not know how long it will last, but after 1 hour your company's electricity is fully restored.

SUMMARY:

Conditions:	«SEASON1» weekday	**Start time:**	«ONSET»
Duration:	1 hour	**End time:**	«END3»

20. Considering **all** of the costs you might experience as a result of this **<u>1-hour «SEASON1» weekday outage beginning at «ONSET»</u>**, please estimate the total costs for an assumed "Best Case" scenario, the cost for a "Typical Case" scenario and the cost for a "Worst Case" scenario. Please enter zero if there are no costs.

$__________	**$**__________	**$**__________
Lowest Total Outage Cost **(Best Case)**	Most Likely Total Outage Cost **(Typical Case)**	Highest Total Outage Cost **(Worst Case)**

Case 4:
On a «SEASON1» weekday, a complete power outage occurs at «ONSET» without any warning. You do not know how long it will last, but after 8 hours your company's electricity is fully restored.

SUMMARY:

Conditions:	«SEASON1» weekday	**Start time:**	«ONSET»
Duration:	8 hours	**End time:**	«END4»

21. Considering **all** of the costs you might experience as a result of this **8-hour «SEASON1» weekday outage beginning at «ONSET»**, please estimate the total costs for an assumed "Best Case" scenario, the cost for a "Typical Case" scenario and the cost for a "Worst Case" scenario. Please enter zero if there are no costs.

$__________	**$**__________	**$**__________
Lowest Total Outage Cost **(Best Case)**	Most Likely Total Outage Cost **(Typical Case)**	Highest Total Outage Cost **(Worst Case)**

Case 5:
On a «SEASON1» weekday, a complete power outage occurs at «ONSET» without any warning. You do not know how long it will last, but after 24 hours your company's electricity is fully restored.

SUMMARY:

Conditions:	«SEASON1» weekday	**Start time:**	«ONSET»
Duration:	24 hours	**End time:**	«END5»

22. Considering **all** of the costs you might experience as a result of this **24-hour «SEASON1» weekday outage beginning at «ONSET»**, please estimate the total costs for an assumed "Best Case" scenario, the cost for a "Typical Case" scenario and the cost for a "Worst Case" scenario. Please enter zero if there are no costs.

$__________	**$**__________	**$**__________
Lowest Total Outage Cost **(Best Case)**	Most Likely Total Outage Cost **(Typical Case)**	Highest Total Outage Cost **(Worst Case)**

Case 6:
On a «SEASON2» weekday, a complete power outage occurs at «ONSET» without any warning. You do not know how long it will last, but after 4 hours your company's electricity is fully restored.

SUMMARY:

Conditions:	«SEASON2» weekday	**Start time:**	«ONSET»
Duration:	4 hours	**End time:**	«END6»

23. Considering **all** of the costs you might experience as a result of this **4-hour «SEASON2» weekday outage beginning at «ONSET»**, please estimate the total costs for an assumed "Best Case" scenario, the cost for a "Typical Case" scenario and the cost for a "Worst Case" scenario. Please enter zero if there are no costs.

$__________	**$**__________	**$**__________
Lowest Total Outage Cost **(Best Case)**	Most Likely Total Outage Cost **(Typical Case)**	Highest Total Outage Cost **(Worst Case)**

WHAT LEVEL OF RELIABILITY IS ACCEPTABLE?

[Utility] works hard to prevent power outages, but eliminating all outages could be very costly, if not impossible.

The following questions help us understand what you consider acceptable service from [Utility].

24. If each of the following occurred, would you think you were getting acceptable or unacceptable service from [Utility]? Please check a box for each statement whether you find the outage period acceptable or unacceptable.

Outages lasting **1 minute or less...**

	Acceptable	Unacceptable	Don't Know
Once a week	☐	☐	☐
Once a month	☐	☐	☐
Once every 3 months	☐	☐	☐
Once every 6 months	☐	☐	☐
Once a year	☐	☐	☐
Once every 5 years	☐	☐	☐

Outages lasting **between 1 minute and 1 hour...**

	Acceptable	Unacceptable	Don't Know
Once a week	☐	☐	☐
Once a month	☐	☐	☐
Once every 3 months	☐	☐	☐
Once every 6 months	☐	☐	☐
Once a year	☐	☐	☐
Once every 5 years	☐	☐	☐

Outages lasting **between 1 hour and 4 hours…**

	Acceptable	Unacceptable	Don't Know
Once a week	☐	☐	☐
Once a month	☐	☐	☐
Once every 3 months	☐	☐	☐
Once every 6 months	☐	☐	☐
Once a year	☐	☐	☐
Once every 5 years	☐	☐	☐

ABOUT YOUR BUSINESS

Some background information about your company will help us understand how power outages affect your type of business.

Please remember, all of your answers are *confidential*. Your name and address will be kept anonymous and will not be associated with the information you provide.

25. Which of the following categories best describes your business? (Please check one.)

- ❑1 Agriculture/Agricultural Processing
- ❑2 Assembly/Light Industry
- ❑3 Chemicals/Paper/Refining
- ❑4 Food Processing
- ❑5 Grocery Store/Restaurant
- ❑6 Lodging (hotel, health care facility, dormitory, prison, etc.)
- ❑7 High Tech
- ❑8 Lumber/Mining/Plastics
- ❑9 Office
- ❑10 Oil/Gas Extraction
- ❑11 Retail
- ❑12 Stone/Glass/Clay/Cement
- ❑13 Transportation
- ❑14 Utility
- ❑15 Other (please specify):_____________________________

26. What is the approximate square footage of the facility printed on the front cover? (Note: "facility" refers to the building(s) that your business occupies at the location shown on the front page of this survey)

__________ Square feet

27. How many **full-time** (30+ hours per week) employees are employed by your company at that location?

__________ Full-time employees

28. List the number of people employed by your business at this company location in each of the following categories:

__________ # of part-time year-round employees

__________ # of full-time seasonal employees

__________ # of part-time seasonal employees

29. What is the approximate value of your business's <u>total</u> annual revenue?

$__________ per year

30. What is the approximate value of your business's <u>total</u> annual expenses (including labor, rent, materials, and other overhead expenses)?

$__________ per year

31. Approximately what percentage of your business's annual operating budget is spent on electricity?

__________ %

32. Does your company have any electrical equipment that is sensitive to fluctuations in voltage, frequency, short interruptions (less than two seconds), or other such irregularities in electricity supply? (If yes, please state the type of equipment.)

❑1 No
❑2 Yes ---->What equipment? ________________________________

33. Does your business own or rent/lease any of the following devices to protect this equipment? (Please check all that apply.)

❑1 Back-up generator(s)
❑2 Uninterruptible power supply
❑3 Line conditioning device(s)
❑4 Surge suppressor(s)
❑5 Isolation transformer(s)

34. Does your business have any electrical equipment that would continue to operate during a power outage? (If yes, please state the type of equipment.)

❑1 No
❑2 Yes ----->What equipment? ________________________________

Please share any additional comments:

____

____

____

____

____

____

____

____

____

THANK YOU FOR YOUR HELP!

Please provide your contact information so that we may mail you the incentive check.

The incentive check can be made out to any individual or charitable organization as designated by you.

If you choose not to accept any incentive, please write "decline."

Name on check: ____

Address (Line 1): ____

Address (Line 2): ____

City: ____

State: ____

Zip Code: ____

To receive your $50 compensation, please fax your completed survey to [FAX NUMBER] or return this survey in the enclosed business reply envelope to:

[COMPANY AND ADDRESS]

Appendix D. Large Business Survey Instrument

This appendix contains the large business survey instrument from a distribution planning study. The survey was customized to serve the purpose of the utility undertaking the study. The survey instrument includes variation in seasonality instead of variation in day of week (weekend vs. weekday). Fields enclosed in double brackets (<< >>) indicate fields for a mail merge.

This survey instrument is a guide and the study team can modify questions or descriptions at its discretion to add clarity. However, study teams should exercise caution when making significant changes to the format or content of the interruption cost survey so as not to introduce bias. In addition, if the study team wants to compare results to those of past studies, it should not make major changes to the instrument.

Associated Delivery Numbers (Acct #)

ID #: «ID»

Date of Interview: ____________________

Interviewer Name: ____________________

Interview Start Time: __________________

Interview End Time: __________________

Name:	Title:
Name:	Title:
Name:	Title:

I would like to talk to you about the costs of power outages for:
(Describe the part of the site served by the selected deliveries.)

Company Name: ____

Service Address: ____

If delivery serves only part of the site, describe location served:

____

____

____

OUTAGE SCENARIOS

Case	Season	Day	Start Time	End Time	Duration
1	«SEASON1»	Weekday	«ONSET»	«END1»	4 hours
2	«SEASON1»	Weekday	«ONSET»	«END2»	1 minute
3	«SEASON1»	Weekday	«ONSET»	«END3»	1 hour
4	«SEASON1»	Weekday	«ONSET»	«END4»	8 hours
5	«SEASON1»	Weekday	«ONSET»	«END5»	24 hours
6	«SEASON2»	Weekday	«ONSET»	«END6»	4 hours

What are the operating hours of this facility?

Use military time. If open 24 hours, use 00:00 to 00:00.

	Weekday Open	Weekday Close	Saturday Open	Saturday Close	Sunday Open	Sunday Close
Shift 1						
Shift 2						
Shift 3						

PRODUCT AND PROCESS DESCRIPTION

1) What products do you make and/or what services do you provide at this facility?

____

____

____

____

____

2) What processes do you use to make these products and/or generate these services?

____

____

____

____

____

OUTAGE EXPERIENCE

In the past 12 months, about how many outages of the durations listed below have you had at this business location? Write a number in each blank. *(Use 0 if none.)*

3.1) Short duration or momentary (one minute or less) _______

3.2) Longer than one minute and up to ½ hour _______

3.3) Longer than ½ hour and up to 1 hour _______

3.4) Longer than 1 hour and up to 4 hours _______

3.5) Longer than 4 hours and up to 24 hours _______

3.6) Over 24 hours _______

MOST RECENT OUTAGE EVENTS

Please describe your three most recent power outages:

	Outage Date *Mo/Yr*	Duration *Hrs/Mins/Secs*	Time *Military*	Weather Conditions *Clear/Stormy*	Description of Impacts
3.7)	_______	_________	______	________	____
3.8)	_______	_________	______	________	____
3.9)	_______	_________	______	________	____

4) What normally happens to your facility's operations when a prolonged power outage (lasting more than one minute) occurs?

(Prompt for major equipment affected, worst effects on operations, etc.)

____

____

____

5.1) Does an outage at this location have financial effects on other sites owned by your company?

1) Yes 2) No *(if No, skip to Q5.4)*

5.2) What type(s) or duration(s) of outages at this location have financial effects on other sites owned by your company?

(Probe for interdependencies of the production network.)

____

____

____

5.3) What are the specific financial effects?

____

____

____

____

5.4) Does an outage at this location have financial effects at your customers' sites?

1) Yes 2) No

6.1) Does your firm generate any of its own electricity (separate from backup power)?

1) Yes 2) No *(if No, skip to Q6.4)*

6.2) What percentage of your electrical demand is supplied by your generation equipment?

_______________ %

6.3) What is the rated capacity of your generation equipment?

____________ Circle one: kW MW hp

6.4) Does your firm have some form of backup electrical power?

1) Yes 2) No *(if No, skip to Q1C1)*

6.5) What percentage of your electrical demand could be supplied by your backup generation equipment?

_______________ %

6.6) What is the rated capacity of your backup generation equipment?

____________ Circle one: kW MW hp

The next section describes six different types of power outages. We would like to know the costs to your business of adjusting to each of these power outages. **Assume that all of the described outages arise from issues associated with [Utility's] infrastructure and occur <u>without advance warning</u>, which means that you do not initially know how long each outage will last.**

For many businesses, the costs of a power outage depend upon the particular situation, and may vary from day to day depending upon business conditions. For each outage type, please estimate the costs that you would be most likely to have under average circumstances.

Since some businesses have more than one building at one location, and others have multiple buildings in several locations, please remember to fill out these questions thinking <u>only</u> about the building(s) that your business occupies at the location specified for this survey.

It is important to try to answer all of the questions. If a question is difficult for you to answer, please give us an estimate and feel free to provide any comments about your answer.

Case	Season	Day	Start Time	End Time	Duration
1	«SEASON1»	Weekday	«ONSET»	«END1»	4 hours

1C1) How long would activities stop or slow down as a result of this outage? ___hr ___min
(if zero, skip to Q.1C6)

1C2) By what percentage would activities stop or slow down? _________ %
1C3) What is the value of output (cost plus profit) that would be lost (at least temporarily) while activities are stopped or slowed down due to the outage? _________ $

1C4) What percent of this lost output is likely to be made up? _________ %
1C5) I would estimate that the amount that your firm's revenue or budget would change as a result of the outage would be… IS THAT RIGHT? _________ $

EXTRA MATERIALS COST
1C6) Damage/spoilage to raw or intermediate materials _________ $

1C7) Cost of disposing of hazardous materials _________ $

1C8) Damage to your firm's plant or equipment _________ $

1C9) Costs to run backup generation or equipment _________ $

1C10) Additional materials and other fuel costs to restart facilities _________ $

SAVINGS ON MATERIAL COST (NET OF ANY MAKE-UP PRODUCTION)
1C11) Savings from unused raw and intermediate materials (except fuel) _________ $

1C12) Savings on your firm's fuel (electricity) bill _________ $

1C13) Scrap value of damaged products or inputs _________ $

LABOR COST
1C14) How would the lost output most likely be made up? *Check all that apply.*

____ a) Overtime

____ b) Extra shifts

____ c) Work more intensely

____ d) Reschedule work

____ e) Other (specify: ____)

1C15) Labor costs to make-up lost output _________ $

1C16) Extra labor costs to restart activities _________ $

1C17) Savings from wages that were not paid _________ $

1C18) Other costs _________ $

1C19) Other savings _________ $

1C20) **Total costs** *(Ask only if respondent will not provide component costs)* _________ $

Case	Season	Day	Start Time	End Time	Duration
2	«SEASON1»	Weekday	«ONSET»	«END2»	1 minute

2C1) How long would activities stop or slow down as a result of this outage? ___hr ___min
(if zero, skip to Q.2C6)

2C2) By what percentage would activities stop or slow down? _________ %
2C3) What is the value of output (cost plus profit) that would be lost (at least temporarily) while activities are stopped or slowed down due to the outage? _________ $

2C4) What percent of this lost output is likely to be made up? _________ %
2C5) I would estimate that the amount that your firm's revenue or budget would change as a result of the outage would be… IS THAT RIGHT? _________ $

EXTRA MATERIALS COST
2C6) Damage/spoilage to raw or intermediate materials _________ $

2C7) Cost of disposing of hazardous materials _________ $

2C8) Damage to your firm's plant or equipment _________ $

2C9) Costs to run backup generation or equipment _________ $

2C10) Additional materials and other fuel costs to restart facilities _________ $

SAVINGS ON MATERIAL COST (NET OF ANY MAKE-UP PRODUCTION)
2C11) Savings from unused raw and intermediate materials (except fuel) _________ $

2C12) Savings on your firm's fuel (electricity) bill _________ $

2C13) Scrap value of damaged products or inputs _________ $

LABOR COST
2C14) How would the lost output most likely be made up? *Check all that apply.*

____ a) Overtime

____ b) Extra shifts

____ c) Work more intensely

____ d) Reschedule work

____ e) Other (specify: ____)

2C15) Labor costs to make-up lost output _________ $

2C16) Extra labor costs to restart activities _________ $

2C17) Savings from wages that were not paid _________ $

2C18) Other costs _________ $

2C19) Other savings _________ $

2C20) **Total costs** *(Ask only if respondent will not provide component costs)* _________ $

Case	Season	Day	Start Time	End Time	Duration
3	«SEASON1»	Weekday	«ONSET»	«END3»	1 hour

3C1) How long would activities stop or slow down as a result of this outage? ___hr ___min
(if zero, skip to Q.3C6)

3C2) By what percentage would activities stop or slow down? __________ %
3C3) What is the value of output (cost plus profit) that would be lost (at least temporarily) while activities are stopped or slowed down due to the outage? __________ $

3C4) What percent of this lost output is likely to be made up? __________ %
3C5) I would estimate that the amount that your firm's revenue or budget would change as a result of the outage would be… IS THAT RIGHT? __________ $

EXTRA MATERIALS COST
3C6) Damage/spoilage to raw or intermediate materials __________ $

3C7) Cost of disposing of hazardous materials __________ $

3C8) Damage to your firm's plant or equipment __________ $

3C9) Costs to run backup generation or equipment __________ $

3C10) Additional materials and other fuel costs to restart facilities __________ $

SAVINGS ON MATERIAL COST (NET OF ANY MAKE-UP PRODUCTION)
3C11) Savings from unused raw and intermediate materials (except fuel) __________ $

3C12) Savings on your firm's fuel (electricity) bill __________ $

3C13) Scrap value of damaged products or inputs __________ $

LABOR COST
3C14) How would the lost output most likely be made up? *Check all that apply.*

____ a) Overtime

____ b) Extra shifts

____ c) Work more intensely

____ d) Reschedule work

____ e) Other (specify: ____)

3C15) Labor costs to make-up lost output __________ $

3C16) Extra labor costs to restart activities __________ $

3C17) Savings from wages that were not paid __________ $

3C18) Other costs __________ $

3C19) Other savings __________ $

3C20) **Total costs** *(Ask only if respondent will not provide component costs)* **__________ $**

Case	Season	Day	Start Time	End Time	Duration
4	«SEASON1»	Weekday	«ONSET»	«END4»	8 hours

4C1) How long would activities stop or slow down as a result of this outage? ___hr ___min
(if zero, skip to Q.4C6)

4C2) By what percentage would activities stop or slow down? _________ %
4C3) What is the value of output (cost plus profit) that would be lost (at least temporarily) while activities are stopped or slowed down due to the outage? _________ $

4C4) What percent of this lost output is likely to be made up? _________ %
4C5) I would estimate that the amount that your firm's revenue or budget would change as a result of the outage would be… IS THAT RIGHT? _________ $

EXTRA MATERIALS COST
4C6) Damage/spoilage to raw or intermediate materials _________ $

4C7) Cost of disposing of hazardous materials _________ $

4C8) Damage to your firm's plant or equipment _________ $

4C9) Costs to run backup generation or equipment _________ $

4C10) Additional materials and other fuel costs to restart facilities _________ $

SAVINGS ON MATERIAL COST (NET OF ANY MAKE-UP PRODUCTION)
4C11) Savings from unused raw and intermediate materials (except fuel) _________ $

4C12) Savings on your firm's fuel (electricity) bill _________ $

4C13) Scrap value of damaged products or inputs _________ $

LABOR COST
4C14) How would the lost output most likely be made up? *Check all that apply.*

____ a) Overtime

____ b) Extra shifts

____ c) Work more intensely

____ d) Reschedule work

____ e) Other (specify: ____)

4C15) Labor costs to make-up lost output _________ $

4C16) Extra labor costs to restart activities _________ $

4C17) Savings from wages that were not paid _________ $

4C18) Other costs _________ $

4C19) Other savings _________ $

4C20) **Total costs** *(Ask only if respondent will not provide component costs)* **_________ $**

Case	Season	Day	Start Time	End Time	Duration
5	«SEASON1»	Weekday	«ONSET»	«END5»	24 hours

5C1) How long would activities stop or slow down as a result of this outage? ___hr ___min
(if zero, skip to Q.5C6)

5C2) By what percentage would activities stop or slow down? __________ %

5C3) What is the value of output (cost plus profit) that would be lost (at least temporarily) while activities are stopped or slowed down due to the outage? __________ $

5C4) What percent of this lost output is likely to be made up? __________ %

5C5) I would estimate that the amount that your firm's revenue or budget would change as a result of the outage would be… IS THAT RIGHT? __________ $

EXTRA MATERIALS COST

5C6) Damage/spoilage to raw or intermediate materials __________ $

5C7) Cost of disposing of hazardous materials __________ $

5C8) Damage to your firm's plant or equipment __________ $

5C9) Costs to run backup generation or equipment __________ $

5C10) Additional materials and other fuel costs to restart facilities __________ $

SAVINGS ON MATERIAL COST (NET OF ANY MAKE-UP PRODUCTION)

5C11) Savings from unused raw and intermediate materials (except fuel) __________ $

5C12) Savings on your firm's fuel (electricity) bill __________ $

5C13) Scrap value of damaged products or inputs __________ $

LABOR COST

5C14) How would the lost output most likely be made up? *Check all that apply.*

____ a) Overtime

____ b) Extra shifts

____ c) Work more intensely

____ d) Reschedule work

____ e) Other (specify: ____)

5C15) Labor costs to make-up lost output __________ $

5C16) Extra labor costs to restart activities __________ $

5C17) Savings from wages that were not paid __________ $

5C18) Other costs __________ $

5C19) Other savings __________ $

5C20) **Total costs** *(Ask only if respondent will not provide component costs)* **__________ $**

Case	Season	Day	Start Time	End Time	Duration
6	«SEASON2»	Weekday	«ONSET»	«END6»	4 hours

6C1) How long would activities stop or slow down as a result of this outage? ___hr ___min
(if zero, skip to Q.6C6)

6C2) By what percentage would activities stop or slow down? __________ %
6C3) What is the value of output (cost plus profit) that would be lost (at least temporarily) while activities are stopped or slowed down due to the outage? __________ $

6C4) What percent of this lost output is likely to be made up? __________ %
6C5) I would estimate that the amount that your firm's revenue or budget would change as a result of the outage would be… IS THAT RIGHT? __________ $

EXTRA MATERIALS COST
6C6) Damage/spoilage to raw or intermediate materials __________ $

6C7) Cost of disposing of hazardous materials __________ $

6C8) Damage to your firm's plant or equipment __________ $

6C9) Costs to run backup generation or equipment __________ $

6C10) Additional materials and other fuel costs to restart facilities __________ $

SAVINGS ON MATERIAL COST (NET OF ANY MAKE-UP PRODUCTION)
6C11) Savings from unused raw and intermediate materials (except fuel) __________ $

6C12) Savings on your firm's fuel (electricity) bill __________ $

6C13) Scrap value of damaged products or inputs __________ $

LABOR COST
6C14) How would the lost output most likely be made up? *Check all that apply.*

____ a) Overtime

____ b) Extra shifts

____ c) Work more intensely

____ d) Reschedule work

____ e) Other (specify: ____)

6C15) Labor costs to make-up lost output __________ $

6C16) Extra labor costs to restart activities __________ $

6C17) Savings from wages that were not paid __________ $

6C18) Other costs __________ $

6C19) Other savings __________ $

6C20) **Total costs** *(Ask only if respondent will not provide component costs)* **__________ $**

7.1) Now that we have discussed the *direct* costs associated with these outages, would you experience any *intangible* costs such as loss of good will, potential liability, or loss of future customers?

1) Yes (*if Yes, please explain)*
2) No

____

____

____

ACCEPTABLE LEVEL OF RELIABILITY

[Utility] works hard to prevent power outages, but eliminating all outages would be very costly, if not impossible. The following questions help us understand what you consider an acceptable level of service reliability from [Utility].

8.1) If each of the following occurred, would you think you were getting acceptable or unacceptable service from [Utility]?

Outages lasting **1 minute or less...**

	Acceptable	Unacceptable	Don't Know
Once a week	☐	☐	☐
Once a month	☐	☐	☐
Once every 3 months	☐	☐	☐
Once every 6 months	☐	☐	☐
Once a year	☐	☐	☐
Once every 5 years	☐	☐	☐

Outages lasting **between 1 minute and 30 minutes...**

	Acceptable	Unacceptable	Don't Know
Once a week	☐	☐	☐
Once a month	☐	☐	☐
Once every 3 months	☐	☐	☐
Once every 6 months	☐	☐	☐
Once a year	☐	☐	☐
Once every 5 years	☐	☐	☐

Outages lasting **about an hour...**

	Acceptable	Unacceptable	Don't Know
Once a week	☐	☐	☐
Once a month	☐	☐	☐
Once every 3 months	☐	☐	☐
Once every 6 months	☐	☐	☐
Once a year	☐	☐	☐
Once every 5 years	☐	☐	☐

Outages lasting **between 1 hour and 4 hours…**

	Acceptable	Unacceptable	Don't Know
Once a week	☐	☐	☐
Once a month	☐	☐	☐
Once every 3 months	☐	☐	☐
Once every 6 months	☐	☐	☐
Once a year	☐	☐	☐
Once every 5 years	☐	☐	☐

ABOUT YOUR BUSINESS

Some background information about your business will help us understand how power outages affect your type of business. Please remember, all of your answers are *confidential*. Your name and address will be kept anonymous and will not be associated with the information you provide.

9.1) Which one of the following categories best describes your business?

- ❑ Agriculture/Agricultural Processing
- ❑ Assembly/Light Industry
- ❑ Chemicals/Paper/Refining
- ❑ Food Processing
- ❑ Grocery Store/Restaurant
- ❑ Lodging (hotel, health care facility, dormitory, prison, etc.)
- ❑ High Tech
- ❑ Lumber/Mining/Plastics
- ❑ Office
- ❑ Oil/Gas Extraction
- ❑ Retail
- ❑ Stone/Glass/Clay/Cement
- ❑ Transportation
- ❑ Utility
- ❑ Other *(please specify)*: ______________________________

9.2) What is the approximate square footage of the facility?

__________ Square feet

9.3) How many **full-time** (30+ hours per week) employees are employed by your business at this location?

__________ Full-time employees

9.4) List the number of people employed by your business at this location in each of the following categories:

__________ # of part-time year-round employees

__________ # of full-time seasonal employees

__________ # of part-time seasonal employees

9.5) What is the approximate value of your business's annual operations or services (income)?

$_____________ per year

9.6) What is the approximate value of your business's <u>total</u> annual expenses (including labor, rent, materials, and other overhead expenses)?

$_____________ per year

9.7) Approximately what percentage of your business's annual operating budget is spent on electricity?

__________ %

That concludes our interview today. Thank you very much for your time.

Please have customer sign / initial below acknowledging receipt of the $150 check.

Customer Name: ____ Date: _____________________

FOR INTERNAL USE ONLY:

Based on your observations of this facility, give a brief summary of the facility, any unusual occurrences with their power supply, and the critical factors that minimize and/or exacerbate outage costs.

____

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