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Prepared for the
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Table of Contents

List of Figures

List of Tables

Acronyms and Abbreviations

ACI	avoided customer interruptions
ACMI	avoided customer minutes of interruption
AEP Texas	American Electric Power Texas Inc. (Texas)
ALJ	administrative law judge
Berkeley Lab	Lawrence Berkeley National Laboratory
BGE	Baltimore Gas & Electric (Maryland)
CAIDI	customer average interruption duration index
C&I	commercial and industrial
CAL FIRE	California Department of Forestry and Fire Protection
CBA	cost-benefit analysis
CEA	cost-effectiveness analysis
COMAR	Code of Maryland Regulations
Con Ed	Consolidated Edison (New York)
CPUC	California Public Utilities Commission
DOE	U.S. Department of Energy
EOP	Executive Office of the President
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas (Texas)
ERI	electric reliability investment
ERP	emergency response plan
FEMA	U.S. Federal Emergency Management Agency
FERC	Federal Energy Regulatory Commission
FPL	Florida Power and Light (Florida)
FPSC	Florida Public Service Commission
FUL	Finance Unit Lead
GAO	U.S. Government Accounting Office
GCP	gross city product
GDP	gross domestic product
GMLC	U.S. DOE Grid Modernization Laboratory Consortium
GO	General order
HFTD	high-fire-threat district
ICCA	incremental cost and capitalization approach
ICE	interruption cost estimate
IOU	investor-owned utility
ISO-NE	Independent System Operator of New England
kWh	kilowatt-hour
LDWI	long-duration, widespread power interruption
MAV	multi-attribute value
MDPSC	Maryland Public Service Commission
MEA	Maryland Energy Administration
MSCR	major storm cost reserve

MWh	mega-watt hour
NAS	National Academies of Sciences
NCEI	National Centers for Environmental Information
NESC	National Electrical Safety Code
NHC	National Hurricane Center
NHPUC	New Hampshire Public Utilities Commission
NIAC	National Infrastructure Advisory Council
NIST	National Institute of Standards and Technology
NOAA	National Oceanic and Atmospheric Administration
NYPSC	State of New York Public Service Commission
O&M	operations and maintenance
PUCT	Public Utility Commission of Texas
RAMP	risk assessment mitigation phase
REP	reliability enhancement plan
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SDG&E	San Diego Gas & Electric (California)
S-MAP	safety model assessment proceedings
SRAF	storm recovery adjustment factor
TAC	Texas Administrative Code
TDU	transmission and distribution utility
TPTA	Transmission Permitting and Technical Assistance Division (DOE)
UES	Unitil Energy Systems, Inc. (New Hampshire)
USGCRP	U.S. Global Change Research Program
VMP	vegetation management plan
VOLL	value of lost load

Executive Summary

The risks of long-duration, widespread interruptions (LDWIs) in electrical power are a concern of U.S. regulators, the electric power industry, and stakeholders. Those responsible for making decisions about increasingly costly investments to prevent such interruptions and to facilitate rapid recovery when they do occur need relevant information on which to base those decisions. Although a number of studies have examined the physical and engineering impacts of extreme weather and other precipitating events on the bulk power system, decision makers evaluating investments in preventive strategies need information on the costs of past power interruptions and the benefits of preventing them in the future. This paper contributes to addressing this need by offering six case studies that detail the economics, at the level of the utility service territory, of power interruptions caused by extreme weather and lasting from a few days to several weeks. These intermediate-duration interruptions have been, and will continue to be, the most common type of major electric power disruption. They are longer than the short-term disruptions addressed in utility reliability planning, but not as long or widespread geographically as the national-scale interruptions with durations of many weeks, months, or longer that have been examined in some recent studies. Through case studies, we are able to address the five questions below that have important policy and long-term planning implications for reducing power system vulnerabilities.

1. How do utilities assess the costs of system damage caused by extreme weather and the costs of recovering from this damage?

Utilities conduct detailed assessments of physical impacts on their systems from the extreme weather events and of response and recovery operations. These assessments form the basis of utility petitions to regulators for recovery of these costs (see Table ES-1). The petitions are based on cost accounting in categories such as materials, labor, and other (e.g., providing emergency services to customers). However, the cost categories are not reported across utilities in a consistent manner that allows for easy comparison.

Table ES-1. Availability of economic information related to cost recovery

Case Study	Precipitating Event(s)	Transmission System Costs	Distribution System Costs	Generation System Costs	Increased Customer Service Costs	Other Costs
Florida	Hurricanes of 2004 and 2005	●	●	●	●	●
New York	Tropical Storm Sandy	●	●	●	●	●
Texas	Hurricanes of 2005, 2008, and 2017	●	●	N/A	◒	●

Case Study	Precipitating Event(s)	Transmission System Costs	Distribution System Costs	Generation System Costs	Increased Customer Service Costs	Other Costs
California	2007 Southern California wildfires	○	○	○	○	○
New Hampshire	Severe fall and winter storms	N/A	●	N/A	○	○
Maryland	2012 Derecho	◒	◒	N/A	●	○

Legend: Full circle = extensive publicly available documentation; half-circle = moderate publicly available documentation; empty circle = little/no publicly available documentation.

2. How do utilities estimate customer costs of past power interruptions?

Utilities in the case studies report statistics, such as numbers and locations of customers without power and duration of outages, but, with one exception, do not monetize these impacts.

3. How do utilities or others estimate the costs and benefits of investments to reduce power system vulnerabilities to future extreme weather events?

Utility and customer costs and benefits: As a rule, the costs of preventive investments can be estimated with reasonable accuracy, but the economic benefits are very uncertain. Most of the utilities' and regulators' economic assessments of these investments are based on cost-effectiveness techniques that are typically used in reliability analysis. In several of the case studies, utilities or regulators use additional techniques and information. One utility applies avoided customer interruption cost data from the Lawrence Berkeley National Laboratory Interruption Cost Estimate (ICE) Calculator to value potential investments in a cost-benefit analysis, and one regulatory body uses these data to value benefits in a secondary calculation supporting cost-effectiveness analysis. However, the ICE Calculator is based on economic surveys of short-term interruptions (up to 16 hours). There are currently no examples, among these case studies or more generally, of utilities using customer interruption cost data specifically applicable to interruptions of several days or weeks or longer (rather than, e.g., extrapolated data based on shorter interruptions); therefore, it is difficult to gauge the accuracy of utilities' estimates of the benefits to customers from investments to prevent longer-duration interruptions. Furthermore, there is little or no evidence that avoided societal impacts other than customer cost are being formally included in cost-benefit analyses or as a supplement to cost-effectiveness analysis.

Regional economic analysis: No utility in our case studies analyzes past or potential local or regional economic impacts of power interruptions, but one municipal government (whose territory encompasses the relevant utility service territory) did so. Because these types of analyses would provide local or regional economy-wide estimates of the benefits – avoided costs – of preventing future interruptions, it is likely that these types of benefits are significantly undervalued in the current regulatory process. Table ES-2 shows the availability of economic information related to preventing or mitigating future impacts as well as information about whether a cost-benefit or cost-effectiveness analysis was conducted.

Table ES-2. Availability of economic information related to preventing or mitigating future impacts

Case Study	Precipitating Event(s)	Avoided Customer Interruption Costs	Avoided Regional Economic Impacts	Other Avoided Societal Impacts	Other	Cost-Effectiveness Analysis?	Cost-Benefit Analysis?
Florida	Hurricanes of 2004 and 2005	○	○	○	○	**Yes**	**No**
New York	Tropical Storm Sandy	●	◒	○	○	**Yes**	**Yes**
Texas	Hurricanes of 2005, 2008, and 2017	○	○	○	○	**Yes**	**Yes**
California	2007 Southern California wildfires	○	○	○	○	**Yes**	**No**
New Hampshire	Severe fall and winter storms	○	○	○	○	**Yes**	**No**
Maryland	2012 derecho	●	○	○	○	**Yes**	**Yes**

Legend: Full circle = extensive publicly available documentation; half-circle = moderate publicly available documentation; empty circle = little/no publicly available documentation.

4. How do utilities and regulators use the concept of resilience in economic assessments of extreme weather impacts and the value of preventive investments?

Utilities and regulators use the term "resilience" extensively in two of the six cases we studied, less extensively in two others, and very little in the remaining two. The "resilience investments" under consideration were for the most part types of storm-hardening and similar measures with which utilities and regulators have considerable experience. However, what has changed from historical norms is that the severity of extreme weather consequences for the power system has increased; therefore, the scale and cost of investments to address these risks have also increased. We find that the challenge in this context is not what "metrics" should be used but rather how to economically value investments developed using these metrics. For these reasons, efforts to identify and address "resilience" as a categorically distinct, substantive phenomenon may not align well with utility and regulatory practices and perspectives.

5. How do regulatory processes influence utilities' economic analysis related to power interruptions?
Laws, regulations, and regulatory practices can significantly influence utilities' preparation for, and response to, LDWIs. Both utilities' petitions for cost recovery after responding to major disruptive events and their proposals for preventive investments are usually assessed in regulatory proceedings that may be adversarial by design in order to encompass the often-competing perspectives and interests of multiple stakeholders. The economic techniques used for analyzing preventive investments generally reflect both regulatory requirements and established practices within the utilities. Moreover, improvements in the economic data and methods that utilities use for investment valuation – e.g., estimating investments' potential benefits – may be outcomes of regulatory proceedings or technical studies under the auspices of regulators rather than being inputs as might be assumed by outside observers.

The case studies reveal a number of areas, summarized below, in which further research could be beneficial to utilities and regulators dealing with risks associated with LDWIs:

Investigate the value of consistently collecting information on past extreme events
There may be value in collecting consistent data, across utilities, in the categories associated with damage to utility infrastructure and other costs associated with system recovery as well as impacts on customers. Consistently collecting this type of information could help identify and prioritize components of the electricity system that may be more vulnerable to extreme weather or other threats.

Improve economic analysis of impacts from LDWIs
The case studies indicate a clear need to develop new estimates of avoided economic impacts of power interruptions on residential, commercial, and industrial customers as well as the broader economy. Surveys should be designed using cutting-edge elicitation techniques to identify customer costs of interruptions that range from hours to weeks. Computational models for estimating not just regional, but also service territory-level, economic impacts of LDWIs should be developed. Perhaps most important, new innovations in survey implementation and regional economic modeling should produce results that can be readily incorporated into existing decision-making processes (see below).

Determine factors that influence regulatory/utility willingness to incorporate, into planning and other processes, the economic information associated with LDWIs
An important research focus should be to study what factors determine whether utilities, regulators, and other stakeholders may be willing to adopt economics information associated with LDWIs into existing regulatory and planning processes. Applied research should also investigate the steps necessary to facilitate adoption of this type of information by regulators and utilities in cases where it is appropriate. A "decision-centered" research philosophy is needed. Existing institutional practices and methods must be understood and respected, and proposed innovations must be justified in terms of the perspectives of the utility and regulatory decision makers.

Assess how utilities might incorporate risk and uncertainty analysis into their existing analytical practices

Risk and uncertainty quantification and management techniques do not appear to be widespread in utility storm-hardening analysis and planning. However, risk and uncertainty associated with economic impacts increase significantly as power interruption durations increase. A topic for research is to assess how utilities might begin to incorporate risk and uncertainty analysis into their planning in a way that builds on and complements their existing analytical practices.

1. Introduction

In recent years, policymakers and regulators at all levels of government, the electric power industry, and other stakeholders have devoted increasing attention to the risks of long-duration, widespread interruptions (LDWIs) in electricity service. There is widely shared concern that these risks are increasing because of increases in extreme weather and a greater potential for deliberate physical and cyber-attacks on the power system, among other threats. Numerous studies and reports have examined aspects of the problem, generally focusing on the bulk power system and emphasizing anticipatory planning, policy, and regulatory needs, as well as preventive measures to reduce the power system's vulnerability to external threats.

A significant amount of policy and technical work on LDWIs has focused on truly catastrophic events that affect multi-state regions or even the entire country and that might last for many weeks or months. These have been termed "black sky" disruptions (Stockton 2014). Research on this topic has generally concentrated on physical and engineering aspects of the electricity system and its vulnerabilities and has been organized around the concept of the system's "resilience" — its capacity to withstand disruptive external events without interrupting service to customers, or to recover expeditiously when interruptions occur.

This report complements existing work in several ways.

First, we study the economic aspects of LDWIs. Broadly speaking, precipitating events, including natural disasters, result in three types of economic impacts related to electric power systems: (1) these events damage or destroy parts of the system's physical infrastructure, thereby imposing costs on utilities (and their customers and shareholders) for repair and recovery; (2) the power interruptions caused by these events impose costs on the utility's customers as a result of loss of electricity; and (3) interruptions of sufficient scope and duration can have indirect impacts on the local or regional economy. We examine each of these types of impacts to assess the status of data and methods that are available and used in practice. We study not just the immediate impacts of precipitating events but also their subsequent influence on regulation and utility planning to minimize systems' vulnerabilities to future events and to facilitate rapid restoration of service when power interruptions occur.

Second, we take an empirical approach, in the form of six case studies of past power interruptions caused by several different types of extreme weather events in utility service territories around the U.S. This pragmatic orientation is in contrast to the more conceptual and speculative approach taken in many studies. Accordingly, we are able to fill a gap in knowledge about the actual effects of such disruptions and the means by which utilities and regulators have addressed these effects. In addition, this approach illustrates the potential value of consistently collecting information on past interruptions in order to inform future preparations and responses.

Third, we examine what could be called "dark sky" events, interruptions that affect large areas and last from several days to a few weeks. These intermediate-scale interruptions are historically the most common type of major electric power disruption. They extend beyond the short outages addressed in utility reliability but are not as long as major catastrophic interruptions that last for months. Our examination of these intermediate types of events fills a gap between conventional electricity reliability analysis and recent research into catastrophic disruptions.

Fourth, we examine the concept of power system *resilience* and its application by utilities and regulators. Although the term is widely used, the practical meaning and operational implications of it remain elusive. Studying how utilities and regulators address resilience may provide valuable insights that have largely been missing in the literature on this topic.

Finally, we take into account the regulatory environments and other institutional influences on utilities' preparations for, and responses to, extreme weather events and associated power interruptions. Utilities' actions are based on laws, regulations, and established practices. These factors may affect the response to past events and preparations for future threats. To date, these factors have received very little attention. We investigate their role and importance.

Specifically, this report addresses five broad questions:

1. *How do utilities assess the costs of system damage caused by extreme weather and the costs of recovering from this damage?*

2. *How do utilities estimate customer costs of past power interruptions?*

3. *How do utilities or others estimate the costs and benefits of investments to reduce power system vulnerabilities to future extreme weather events?*

4. *How do utilities and regulators use the concept of resilience in economic assessments of extreme weather impacts and the value of preventive investments?*

5. *How do regulatory processes influence utilities' economic analysis of power interruptions?*

The premise of the work discussed in this report is that studying examples of actual events can complement existing, primarily conceptual, work on the economics of electric power system vulnerabilities and may provide valuable lessons for utilities, regulators, policy makers, and other stakeholders grappling with the challenges of estimating the costs and benefits of measures to reduce these vulnerabilities. Moreover, examining utility service-territory-level impacts can help link regional and national bulk power system planning to the efforts of utilities and state regulators to increase the resilience of more local electricity distribution systems.

The remainder of this report is organized as follows. In Section 2, we provide examples of previous studies of electricity system vulnerabilities, followed by a discussion of electricity system reliability, event preparedness, and the concept of "dark sky" power interruptions. We then provide background on relevant economic concepts, methods, and data, including cost-effectiveness and cost-benefit analysis; avoided, direct, and indirect economic impacts of power interruptions; and empirical findings and computational modeling. Next, we discuss the implications of this background material and the motivation for our study. Section 2 concludes with an introduction to, and overview of, the six case studies. Sections 3 through 8 present the individual case studies for Florida, New York, Texas, California, New Hampshire, and Maryland. The report concludes with a discussion of our findings and recommendations for future research.

2. Background

2.1 Electricity system vulnerabilities to extreme events

A report by the U.S. National Academies of Science (NAS 2017) examines the increasing vulnerability of the national electric power system to extreme weather as well as to cyber threats, physical attack, and human error. The Academies' report gives a technical and operational overview of the power system; the causes of grid failure and power interruptions; and strategies to anticipate, mitigate, and facilitate recovery from disruptions. Although taking a prospective view, the report briefly mentions several examples of past events and interruptions, including lessons to be drawn from them in planning for future disruptions. The report recommends a number of actions including, but not limited to:

- improving planning and coordination, emphasizing inter-agency, inter-governmental, governmental-electric utility engagement

- increasing the practical and empirical knowledge base on physical/engineering impacts of triggering events and prevention and mitigation of resulting power interruptions

The National Academies also made recommendations specifically to the U.S. Department of Energy (DOE), which include:

- "[developing] comprehensive studies to assess the value to [utility] customers of improved reliability and resilience"

- "[conducting] a coordinated assessment of the numerous resilience metrics being proposed for transmission and distribution systems and [seeking to operationalize] these metrics within the utility setting, with 'engagement with key stakeholders [being] essential.'"

A 2018 report by the U.S. President's National Infrastructure Advisory Council (NIAC 2018) assessed and analyzed the risks of future LDWIs and how to improve the nation's capacity to prepare for, mitigate, and rapidly recover from them. NIAC's study focused on catastrophic disruptions outside the range of historical experience, in which power might be out for months or longer, affecting tens of millions of customers across multiple states. It addressed prospective technical, policy, and regulatory elements of risk management and of preventing or mitigating such catastrophic events. Although the report was generally forward looking, it briefly reviewed five past large power outages and lessons that should be learned from these experiences.

DOE has published several studies on the risks of severe weather and other events to the power system, the physical impacts of these events, and details of resulting power interruptions. DOE (2010) examined the impacts of the 2005 and 2008 hurricanes on U.S. energy infrastructure. A subsequent study (DOE 2013) focused on the impacts of the 2005 and 2008 hurricanes on energy infrastructure in the Northeast, including utility distribution system-level effects. DOE (2015) examined U.S. regional climate change vulnerabilities and the potential impacts of climate change-caused extreme weather events on the energy system. This study used examples of past impacts but did not analyze them in detail. The study also listed examples of "resilience solutions" for potential impacts but did not propose a framework to help utilities, regulators, and other stakeholders evaluate proposed solutions. DOE (2016) presented a comprehensive framework for identifying and analyzing potential climate change threats to the electricity system and measures to prevent or mitigate their impacts, and DOE (2017) provided a technical overview of the modern power grid, identified risks and threats, and discussed grid operations and management strategies for addressing them. The U.S. DOE Grid Modernization Laboratory Consortium (GMLC) has published reference documents that discuss defining "metrics for the purpose of monitoring and tracking system properties of the electric infrastructure as it evolves over time" (GMLC 2017).[1]

Other relevant work sponsored by the federal government includes a 2014 report by the U.S. Government Accountability Office (GAO 2014) on the increasing vulnerabilities of U.S. energy infrastructure to severe weather. GAO found that actions necessary to address these vulnerabilities generally fall into two broad categories: (1) hardening — measures that reduce the vulnerability of infrastructure, and (2) resiliency — measures that speed recovery of the power system in the event of a service disruption. GAO also offered suggestions for how selected federal entities could address these vulnerabilities and summarized various federal roles, by entity, in relation to energy infrastructure. The report mentioned a series of examples of past impacts. More recently, an assessment by the U.S. Global Change Research Program found that U.S. energy infrastructure is becoming increasingly vulnerable to climate-change-caused severe weather and water shortages (USGCRP 2017).[2]

2.2 Resilience, reliability, and "dark sky" power disruptions

Resilience is a widely used rubric in studies of electric power system vulnerability and other related types of analysis. Resilience has been broadly defined by the U.S. Executive Office of the President (EOP) as:

> the ability to prepare for and adapt to changing conditions and to withstand and recover rapidly from disruptions…. Resilience includes the ability to withstand and recover from deliberate attacks, accidents, or naturally-occurring threats or accidents (EOP 2013a).

Beyond this general characterization, the practical meaning of resilience continues to be unclear despite a considerable body of research attempting to make it precise. This research has been predominantly conceptual and prospective rather than pragmatic and empirical, and it has generally not focused on valuation. Many proposals have been made for "metrics" to gauge resilience at varying levels of specificity. With very few exceptions, this work has been mostly of an academic nature, and

[1] The U. S. Department of Defense has a number of energy resilience initiatives under way (Rickerson et al. 2018).

[2] Although they are not the focus of this report, there have also been numerous efforts at state and local levels to address resilience of non-energy infrastructure and systems, such as the State of New Jersey's "Climate and Flood Resilience Program," https://www.nj.gov/dep/bcrp/resilientnj/index.html.

regulators and utilities have not made practical applications of it. Second, a number of prospective "frameworks" have been proposed for making decisions on investments to increase resilience. This work has also been conceptual with little or no grounding in what has actually been accomplished to date by regulators and utilities.

Some experts have sought to clarify the underlying concept of resilience, its relationship to electricity reliability, and the relatively new challenges associated with operationalizing it. A recent paper by the National Regulatory Research Institute discusses the difficult question of determining appropriate levels of investment in measures to prevent or mitigate severe power disruptions, looking at resilience in terms of "…whether [from a public-interest as opposed to utility perspective] a so-called resiliency problem exists" (Costello 2018). Costello notes that the value of such investments has increased as a result of more severe weather and greater risk of cyber-attacks but also highlights the fact that there is a large amount of uncertainty in such investments, particularly with regard to their benefits, and that cost-benefit analysis (CBA) is therefore challenging. Investments to improve resilience may have features of public good in that a larger group of stakeholders beyond utility customers may accrue benefits without bearing the cost. For example, resilience investments may be valued more by system operators than by utilities and regulators, which may tend to underinvest in resilience. Conversely, utilities may be inclined to *over*-invest in electricity infrastructure to increase their asset bases. Costello (2018) cautions that "Regulators need to assure utility customers that they will benefit from improved resilience by at least the cost incurred by the utility to make this improvement," but that as a result of uncertainty in benefits and other complications, "…this is a tough and almost imponderable task, given what we know today."

In a study for the National Association of Regulatory Utility Commissioners, Keogh and Cody (2013) review the concept of resilience, problems with defining it precisely, and its practical application. They highlight distinctions between problems associated with resilience and those associated with conventional reliability issues and propose a risk-management framework for analyzing decisions related to improving power system resilience. This framework is based on three factors: (1) number of customers affected (scale of event); (2) duration of event; and (3) value of lost load (VOLL) by customer. Stockton (2014) points out that consideration of the risks of extreme events and resulting severe power interruptions is generally at utility regulators' discretion and provides suggestions for how utility regulators can conceptualize and operationalize resilience in order to better prepare for these risks. Stockton refers to normal days without major power outages as "blue sky," those with low-intensity weather events as "gray sky," and catastrophic disruptions affecting large regions and lasting potentially for months as "black sky." As indicated above, we therefore use the term "dark sky" to refer to the occurrence of interruptions affecting large parts of, or an entire, utility service territory and lasting from several days to several weeks.

LaCommare et al. (2017) interview public utility commission staff in three jurisdictions – California, Florida, and the District of Columbia – to understand how they assess the economics of investments in reliability and resilience that are proposed to them by utilities. Key findings from this study include: a) little or no distinction is made between reliability and resilience in reviewing proposed projects; b) the costs of investments in reliability or resilience are well understood by utilities and regulators; c) the benefits of such investments are difficult to monetize; and d) there is a need for improved information on the costs that power interruptions impose on utility customers (which can be used to monetize the benefits of investments). LaCommare et al. (2017) also find that most utility requests for regulatory approval of the costs of reliability-resilience investments are made during proceedings around general rate cases.

Measures to mitigate power system impacts of extreme events, including utility storm-hardening and related efforts (e.g., undergrounding distribution lines, managing vegetation), are often called "resilience investments" in that they can reduce weather-caused physical impacts and power interruptions and/or facilitate faster system recovery from these impacts. However, many such investments and similar actions are, in practice, already a focus of utilities and regulators in their existing and ongoing efforts to improve electricity reliability (Finster et al. 2016). We elaborate on this observation in the following subsection.

2.3 Estimating the economic impacts of power interruptions and the value of reliability and resilience investments

2.3.1 Damage to electricity systems caused by extreme events

The first category of electricity system economic impacts caused by extreme events comprises the costs that the utility incurs for repair of damaged infrastructure and restoration of power to customers experiencing interruptions. Examining the details of how utilities assess and report damage to their infrastructure from extreme weather provides insight into the physical and engineering impact metrics that are actually used in practice. Utilities' cost estimates are based directly or indirectly on their accounting practices, which are often subject to regulatory oversight.

2.3.2 Cost-effectiveness and cost-benefit analysis

Electric utilities operate under a compact with state regulators to provide safe, reliable electricity service at rates that are considered just and reasonable. Standards for reliability are not set by law; instead, individual states and utilities have over time evolved understandings about how to balance spending on reliability with expectations of the level of reliability that will be provided. Evaluation of future investments must consider impacts on electricity rates and affordability. In this context, regulatory oversight focuses on ensuring that ratepayer dollars are spent prudently; the common economic criterion for assessing reliability measures is *cost-effectiveness.*

Following an extreme event, regulated utilities are generally required to report any costs that they incur in the course of restoring power to their customers and repairing or replacing damaged distribution, transmission, and generation infrastructure. In recent decades, however, severe electric power interruptions caused by natural disasters have led some commissions and state governments to initiate extraordinary (non-routine) proceedings to review utility response and preparedness for future large, disruptive events, as a result of the expectation that the frequencies and magnitudes of these large events will increase. Such proceedings are primarily driven by the significant costs that LDWIs in particular jurisdictions have imposed upon utility customers. The proceedings aim to develop and implement strategies to prevent such costs in the future by reducing the system's vulnerability to these types of interruptions.

> *Cost-effectiveness analysis* (CEA) is used to identify efficient options for meeting specific goals or targets. In electricity reliability, for example, some states have requirements defined in terms of numerical limits on allowable numbers and durations of customer power interruptions. Utilities are expected to maintain their systems so that these limits are not exceeded. A utility may have multiple options of different costs for meeting its reliability obligation, such as pole replacement, undergrounding, or vegetation management measures. CEA can be used to determine the *least-cost* combination of measures that will meet a particular reliability target.
>
> *Cost-benefit analysis* (CBA) is used to determine the optimal levels of, e.g., investments in reliability or resilience, in terms of both the costs and the resulting benefits of these investments when there are no pre-determined standards or requirements. In this case, the costs of measures such as pole replacement, undergrounding, and vegetation management are compared to their monetized benefits in terms of avoided power interruptions caused by extreme weather or other precipitating events. The CBA criterion is to invest in these measures up to the level at which their incremental benefits equal their incremental costs.

In most cases, these proceedings review the formal or informal standards[3] that were used in the original construction and/or maintenance of electricity infrastructure that has been compromised or damaged, and discussion centers around what standards should apply to rebuilding or redesigning the replacement infrastructure. Sometimes the adequacy (or applicability) of the standard itself is examined, and there is an assessment of whether it should be increased or strengthened to ensure that utilities are "building it back better."

Two problems arise in this type of process. First, utilities and regulators do not have experience in preparing for storms, hurricanes, and other events of unprecedented magnitude. Thus, they may not have sufficient information to determine with complete confidence how much a more stringent standard will reduce their system's vulnerability. Second, higher levels of storm preparedness invariably require greater expenditures than expenditures that are routinely made to maintain acceptable levels of reliability. One implication of the first problem is that utilities' and regulators' established understandings of how to set standards and apply CEA to meeting those standards may not readily apply in this context. An implication of the second problem is that the potential benefits of the

[3] "Standards" refer not only to design standards for physical infrastructure, but also standards for preparedness, such as vegetation management and staffing requirements for emergency response.

greater investments in preparedness become much more salient in the regulatory process. That is, the primary benefits come from reduced customer exposure to future power disruptions. But exactly how much reduction will be achieved for given increases in investment, and whether a given level of reduction is, in colloquial terms, "worth it," becomes an issue.

This issue can be illustrated by the example of evaluating measures to reduce customer outage times after a major storm. Suppose a utility estimates that some type of storm-hardening investment costing $X will reduce the average frequency and/or duration of customer outages by Y%. Should these investments be made? Under the approach of an *a priori* target for reduced outage times (or frequency) and a cost-effectiveness test, the question would be whether Y%/$X was the least-cost option. However, if this is an instance of seeking to increase protection against outages to a greater-than-historical level, setting the target may be part of the problem. It may be the case that $X in expenditures would be considered large in terms of the jurisdiction's historical experience and would be recovered by increasing customer electricity rates. For this reason, assessing the *value* – i.e., the benefits – of these incremental investments becomes important. Estimates of the benefits can be compared to the capital and operations and maintenance (O&M) costs to determine whether the investments are worthwhile. Cost-*benefit* rather than cost-*effectiveness* analysis can be an appropriate methodology for evaluating potential investments in storm-hardening and related measures, especially if the investments are larger than past spending on blue or gray sky reliability measures.

Accordingly, defining and monetizing these benefits is an important step in assessing investments to improve power system resilience in order to avoid or minimize damage from future extreme events. In the next subsection, we review concepts, methods, and empirical information pertaining to this topic.

2.3.3 Direct costs to utility customers

The costs that power interruptions impose on utility customers are defined in several ways, depending in part on the type of customer affected. Interruptions affect commercial and industrial (C&I) utility customers by impeding or curtailing their production of goods and services. Commercial firms may need to close their office facilities because of a lack of lighting and air conditioning, and industrial firms may be unable to run machinery and other systems that manufacture their products.[4] These impacts are generally measured as losses in normalized dollars as functions of the length of the power interruption, time of day and the season, facilities affected, presence of backup generation, current inventory, and other factors.[5] Although terminology varies, these can be described as *direct costs* to these customers.

For residential customers, the standard approach to defining interruption costs is to first define and estimate the economic *utility* (i.e., well-being or worth) that customers derive from using electricity

[4] In some cases this can result in physical damage to facilities, caused by the interruption not the precipitating event. An example is hardening of molten aluminum in pots as a result of loss of power. We thank Carl Pechman for pointing this out.

[5] Normalization may be cost per individual interruption for an average customer, cost per average kilowatt, or per unserved kilowatt-hour (Sullivan et al. 2015).

services such as lighting, heating, and cooling (usually as a function of kilowatt-hours [kWh]). Residential customer costs from a power interruption are then defined in terms of the utility the customer loses as a consequence of electricity curtailments. Another approach to estimating this type of economic value is defining it directly in terms of the value to electricity users of improvements in the reliability of their electricity service, such as reducing the number and/or frequency of power interruptions over the course of a year.

Although the metrics described above for residential customers represent a form of direct cost, they are more often referred to as "avoided costs." This terminology also applies to C&I firms. These quantities are also referred to, both in the research literature and in practice (by utilities and regulators), as VOLL or the "value of [electricity] service."

The terms "avoided" and "value" indicate the primary significance and use of these cost concepts as measures of the potential *benefits* of investments and other measures aimed at avoiding the power interruptions that result in these costs. *That is, the worth of such investments is gauged in terms of the customer economic losses that they may prevent.* This framing of costs and benefits is central to the analysis presented in this report. Historically, most work on the economics of power interruptions has addressed the direct or avoided costs of momentary or short-term interruptions, i.e., those lasting seconds, minutes, or hours, but generally no more than 16 hours (e.g., see Larsen et al. 2019). The standard methodology for estimating the economic impacts of such disruptions is to survey utility customers self-reporting these impacts either retrospectively – actual costs incurred due to a previous interruption – or prospectively – anticipated costs in the event of a hypothetical future interruption(s) of specified severity and particular duration. Residential and small C&I customer surveys are often administered by mail, phone, or on line. Large C&I surveys are typically administered by trained auditors who interview customers in person to facilitate understanding of the question and ensure accuracy of the responses.

The Lawrence Berkeley National Laboratory (Berkeley Lab) Interruption Cost Estimate (ICE) Calculator is an on-line tool based on 34 utility customer interruption cost surveys from across the U.S. This tool is designed for use by utilities, regulators, and others in estimating interruption costs or the avoided costs resulting from investments in power system reliability (Sullivan et al. 2018). Larsen et al. (2018) use the ICE Calculator to project future costs of power interruptions to U.S. utility customers. The study estimates that severe-weather-related interruptions cost utility customers $2-3 billion in any given year. Campbell (2012) and the EOP (2013a) use the estimated customer damage functions for power outages (LaCommare and Eto 2004, Sullivan et al. 2009). Campbell (2012) finds that severe-weather-related power interruptions cost the U.S. economy $20-$55 billion each year, and the EOP finds a range of $5-$75 billion.

A number of other researchers have focused on estimating direct or avoided costs of power interruptions to customers regardless of cause (Swaminathan and Sen 1998; Primen/EPRI 2001; LaCommare and Eto 2006). For example, LaCommare et al. (2018) estimate that the total cost of all power interruptions in the U.S. is roughly $44 billion per year. There is also research on this topic outside the U.S. Richter and Weeks (2016) discuss econometric methods for estimating electricity customers' willingness to pay for improved resilience, using United Kingdom data. Sagebiel (2017) also discusses such methods and estimated willingness to pay for improved reliability among a sample of urban customers in India. Morrissey et al. (2018) estimate the welfare costs of power outages in a region of England. More recently, LaCommare et al. (2018) review improvements in these data over time and use them in developing and applying a framework to estimate the costs of sustained power interruptions. Larsen (2016) proposes a framework for evaluating the costs and benefits of one type of investment in power system resilience: undergrounding transmission and distribution lines. Here, the avoided, direct interruption costs from less frequent and/or shorter-duration power interruptions are some of the benefits considered.

A recent report for National Association of Regulatory Utility Commissioners examines methods for valuing the resilience benefits of distributed energy resources (NARUC/Converge 2019). Zamuda et al. (2019) survey benefit categories used to justify investments that reduce the vulnerability of power systems to extreme weather and climate change. The paper identifies a number of benefit streams that have been included in formal cost-benefit analyses of investments in resilience including *avoided*:

- legal liabilities
- vegetation management costs
- utility revenue loss
- utility customer interruption costs
- injuries and fatalities
- aesthetic costs
- emissions

Interestingly, the Zamuda et al. (2019) study finds a limited number of examples of avoided costs being used in formal cost-benefit analyses of power interruptions lasting more than 24 hours. Perhaps most importantly, Zamuda et al. (2019) finds no examples of avoided, indirect economic impacts on the broader economy being included as benefits in a formal cost-benefit analysis. We discuss these types of regional economic impacts in the following subsection.

2.3.4 Direct and indirect regional economic impacts

In addition to causing direct costs, power interruptions disrupt the flow of commerce among businesses, industries, and entire sectors of the economy. That is, the loss of power to a supplier of some good or service and the resulting reduction (or cessation) of production of that business's products will in turn affect both its suppliers and its purchasers (customers), whose upstream or downstream operations, respectively, may be impeded. For example, loss of power at a steel plant will reduce or stop the production of steel, resulting in a direct cost to the producer from reduction in sales revenue, and potentially causing customers who purchase the plant's steel to slow or shut down their operations (i.e., their manufacture of steel products). The consequent losses of business to the customers result in *indirect* economic impacts of the power interruption on the suppliers. *As discussed* *earlier, avoided economy-wide costs also implicitly define the benefits of investments that might prevent future LDWIs.*

There is significantly less literature on the economic impacts of large-scale, long-duration interruptions than on short-term outages (Larsen et al. 2019). Most of the existing literature detailing these types of impacts is based on computer simulation models of local or regional economies, depending on the scale of the modeled interruptions.[6] These include models that represent supply and demand in markets for goods and services, and how these markets interact, as well as models that focus on the relationship between employment and overall economic output. In the current context, these models are designed or augmented to provide information on electricity use, how it contributes to the functioning of an economy, and the costs resulting from its interruption.

There are a number of reasons for using these types of models. First, they are able to represent and analyze both direct and indirect impacts of power interruptions, an important advantage over customer surveys, which focus on the direct costs to customers. Second, customer surveys are usually targeted at residential, commercial, and industrial customers whereas the models are comprehensive and can in principle analyze power interruption impacts on all sectors of an economy. Third, some types of models incorporate customers' and businesses' adaptive actions to reduce the impacts of interruptions (e.g., rescheduling or relocating production following a power disruption). Fourth, these models can represent effects on economies over time (days, weeks, months) even after the power has been restored. Computational economic modeling has been applied to estimate costs of LDWIs that result from several types of triggering events, both actual historical cases and hypothetical scenarios. For example, Rose et al. (2005) retrospectively study the effect on the metropolitan Los Angeles economy of rolling blackouts that lasted for one to eight hours over several days in California in 2001, during the state's energy crisis. Those authors find that the combined direct and indirect costs amounted to 1.3% of this economy's annual gross output, and that adaptive responses considerably reduced the economic impacts of the blackouts. Greenberg et al. (2007) analyze the economic effects of a power interruption resulting from a hypothetical terrorist attack in New Jersey under various assumptions about the magnitude and duration of the interruption and the speed of recovery. In this study, the most important factor in determining the ultimate economic losses is the impact on state employment. In the most pessimistic scenario, the researchers simulate a loss of 5.5% of power with full restoration after two weeks but a 1.6% reduction in employment relative to the baseline in the first year after the interruption, and a continuing 1.5% reduction after five years. In this scenario, state annual gross domestic product would be reduced by 1.6% ($397 billion) in the first year after the event, 3.3% ($400 billion) in the second year, and 1.8% ($458 billion) in the fifth. There have also been several economic modeling studies of direct and indirect costs of tropical storm Sandy in 2012. For example, Boero and Edwards (2017) estimate the direct and indirect impacts on the U.S. East Coast economy of the Sandy-caused power interruptions to have been roughly 0.83% of baseline regional economic output in 2012, or about $53 billion.

[6] This subsection draws upon Sanstad (2016).

2.3.5 Other impacts that can be monetized

In addition to disruptions of economic activity, other indirect societal impacts of power interruptions can be monetized. For example, a long-duration power interruption at a hospital that has insufficient backup generation capabilities may increase mortality/morbidity rates. A significant amount of literature documents how changes in mortality/morbidity rates can be monetized using value of statistical life estimates and other approaches (e.g., Executive Office of the President 2013b).[7] There may be other co-benefits of hardening infrastructure. Larsen's 2016 cost-benefit analysis of an undergrounding mandate includes avoided aesthetic costs, which are based on improvements in property value that result from removing overhead transmission or distribution lines from a property owner's line of sight.

2.3.6 Strengths and limitations of methods

As with any economic tools or models, survey methods for valuing direct customer costs of power interruptions and computational modeling for estimating economy-wide direct and indirect impacts both have strengths and limitations. Sullivan et al. (2018) comprehensively describe and discuss the limitations of survey methods and applications for direct cost estimation. Sanstad (2016) provides a conceptual and theoretical overview of computational economic models and their application to estimating the costs of LDWIs, discusses several examples, reviews methodological issues and the models' advantages and limitations, and identifies research directions for improving them. A March 2018 expert workshop was convened to understand the advantages and limitations of survey methods and computational modeling and to recommend future research areas to improve economic estimates of LDWIs (Larsen et al. 2019). At that workshop, a number of leading researchers from across the U.S. reported on computational models, survey data, and methods, and offered ideas for further research. Eyer and Rose (2019) presented a modeling framework for analyzing the economic tradeoffs between resilience investments and post-interruption recovery, and Sue Wing and Rose (2019) developed a simple economic model and applied it to studying an earthquake-caused power interruption in the San Francisco Bay Area in order to study the underlying drivers of cost estimates. Shawhan (2019) discussed survey methods for direct cost estimation, and Baik et al. (2019) described a new methodology for estimating residential customers' cost of long- (as opposed to short-) duration interruptions. Schellenberg et al. (2019) surveyed the current data landscape for interruption cost estimation and potential avenues for increasing both the quantity and quality of data for this purpose. Perhaps most importantly, Larsen et al. (2019) identified (1) concerns about using existing survey-based techniques to elicit VOLL for power interruptions lasting longer than 24 hours and (2) the challenges with interpreting and including regional economic model output in formal decision-making processes involving resilience.

[7] Although this topic is not a focus of this study, there have also been studies evaluating non-monetary impacts of extreme weather on electricity and associated societal systems (e.g., Alvehag and Soder 2011, Hines et al. 2009, Ji et al. 2016, Ward 2013).

2.4 Synopsis and rationale for this study

This study is being undertaken for a number of important reasons.

First, there have been a number of regional and national studies of the physical and engineering aspects of electricity system vulnerabilities and catastrophic power interruptions, but few studies detail the economic and other impacts of power interruptions lasting several days up to several weeks. These economic impacts encompass both utilities' costs of repairing and/or replacing infrastructure following a major extreme weather or other event and the potential benefits of investments and other measures to reduce system vulnerability and the likelihood of severe electricity service disruptions. These impacts are increasing. Since the year 1900, four of the five costliest tropical cyclones (including hurricanes) to hit the U. S. mainland in the South, Southeast, and East occurred during the past 15 years.[8] In the West, 15 of the 20 most destructive California wildfires of the past century have occurred since 2000 (CAL FIRE 2019a,b); in Northern California, the Pacific Gas & Electric company has recently resorted to the unprecedented strategy of "public safety power shut-offs" – de-energizing sections of its distribution system to prevent its equipment from igniting fires under extreme weather conditions.[9]

Second, although system resilience has been discussed in many conceptual studies, the meaning of this term and its practical application remain uncertain. As discussed earlier, state regulators make little or no distinction between reliability and resilience in assessing proposed projects, and many of what have been called "resilience investments" are, in practical terms, measures that are already included in utility storm-hardening activities. Because utility proposals for reliability or resilience investments are made and evaluated in regulatory proceedings – and ultimately approved, amended, or disapproved by regulators – the content of regulatory proceedings is important for understanding how reliability and resilience are addressed in practice. In our case studies, we also attempt to identify whether a utility built its system back "better" immediately following the event or whether additional storm-hardening initiatives were undertaken as part of a separate set of regulatory proceedings.

Third, regulators need information to estimate the monetary/financial benefits of such measures, whether they are deemed investments in reliability or resilience. Although we have not discussed it explicitly, this in part reflects the fact that utilities themselves may not have comprehensive and defensible information on the avoided economic impacts of these types of investments.

Fourth, CEA is a common technique for economic evaluation of proposed investments in reliability, but CBA is a more appropriate tool for evaluating investments in infrastructure that will help avoid (or reduce) the economic impact of LDWIs. There are additional benefit categories relevant to investments

[8] Measured in inflation-adjusted dollars – See NHC (2018a).

[9] It is also important to point out that the circumstances surrounding some recent large power disruptions – including Hurricane Harvey in Texas and several wildfires in California – have entailed deaths and extensive property damage and loss. Although these may not have been direct consequences of the power interruptions themselves, the information in this report can contribute to efforts to prevent such tragic impacts of future extreme events on both energy- and non-energy infrastructure and on human systems more generally.

in resilience, including d (1) avoided costs to customers (2) avoided local or regional economy-wide losses. There may also be other types of indirect societal benefits from these types of investments.

Fifth, although only a few modeling studies have estimated state- or regional-level economic losses from power interruptions, the magnitude of these impacts is extremely large, on the order of tens or hundreds of billions of dollars. It follows that avoiding these significant losses is a critical, yet under-studied, benefit that may help justify additional investments in power system resilience.

In summary, results of this research will help improve understanding of the above issues and how they have been addressed in practice. This effort identifies what new information — data, methods, etc. — can help inform utility and regulator decision making aimed at improving the resilience of power systems.

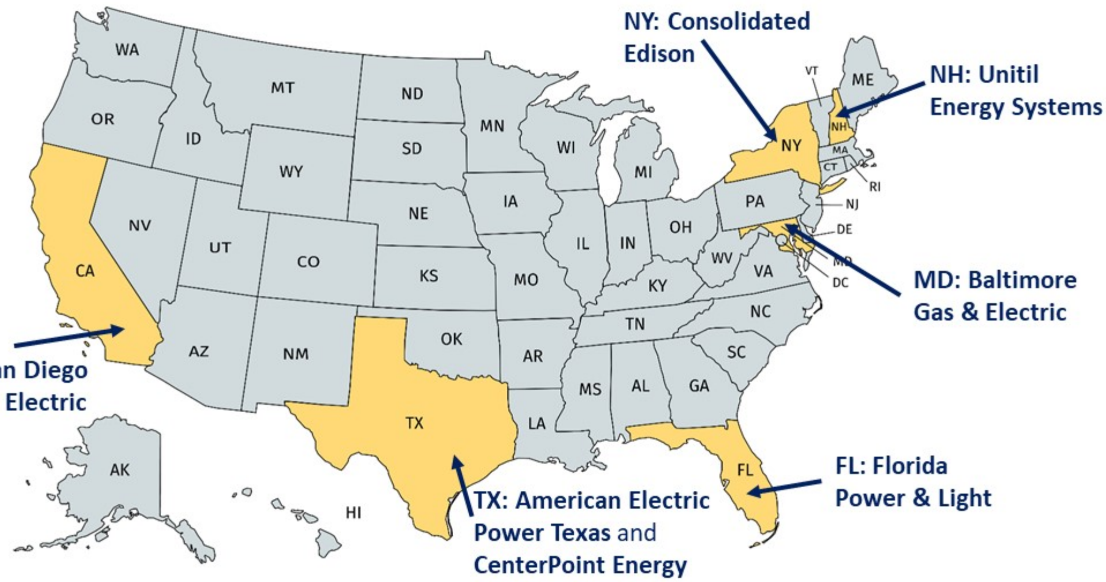
2.5 Overview of the case studies

The case studies that follow come from jurisdictions where extreme weather resulted in a "dark sky" power interruption with disruptions lasting several days up to two weeks. Several of these cases affected parts of states or regions that extended beyond the utility's service territory. However, we focus on individual utilities within the affected areas and on the regulatory processes involved.

The six states and utilities were chosen to provide examples in different parts of the country and to examine the effects of different types of precipitating extreme weather events as well as, in the case of hurricanes, to document whether and how responses to a single type of event may vary. The following utilities and regulatory commissions were studied as part of this research effort (see Figure 2-1):

1. Florida — Florida Power & Light (FPL) and the Florida Public Service Commission (FPSC)
2. New York — Consolidated Edison (Con Ed) and the New York Public Service Commission (NYPSC)
3. Texas — American Electric Power (AEP) Texas and CenterPoint Energy and the Public Utility Commission of Texas (PUCT)
4. California — San Diego Gas & Electric (SDG&E) and the California Public Utilities Commission (CPUC)
5. New Hampshire — Unitil Energy Systems and the New Hampshire Public Utilities Commission (NHPUC)
6. Maryland — Baltimore Gas & Electric (BGE) and the Maryland Public Service Commission (MDPSC)

Figure 2-1. Locations of the six case studies included in this report



Each case study begins with a background summary describing the particular utility, the regulator, the extreme event, and the regulatory response that followed. We then describe the event's physical and engineering impacts on the utility's system, which are the basis for the utility's response to the event and its subsequent application to the regulator for cost recovery. Next, the jurisdiction's requirements for and approach to improving preparation for future extreme events is discussed. In most cases, these requirements reflect the outcome of extensive processes that are initiated by regulators and/or state lawmakers and carried out under the auspices of public utility commissions. We describe the methods and practices for assessing the economic impacts of proposed investments, including cost-effectiveness and cost-benefit analyses, and whether avoided customer interruption costs, regional economic impacts, etc. are incorporated into these assessments. Each case includes tables that summarize the availability of documentation (see the key in Table 2-1). Each case study concludes with a discussion of the role of institutional factors, the relationship of the case study's findings to previous work, and additional commentary on the economic analysis documented in the study.

Table 2-1. Key to the tables throughout this report that document the availability of information on particular categories of economic impacts.

Symbol	Key
●	Extensive publicly available documentation
◒	Moderate amount of publicly available documentation
○	Little/no publicly available documentation

3. Case Study #1: Florida

3.1 Background information

3.1.1 Utility and regulatory body

Florida Power & Light (FPL) is the largest utility in the state of Florida. Incorporated in 1925, it is regulated by the Florida Public Service Commission (FPSC) and serves 10 million customers. Florida and FPL were selected for this case study because of their extensive history of dealing with hurricanes, the relatively large size of the utility, and the scope and sophistication of the utility's storm preparation and response activities.

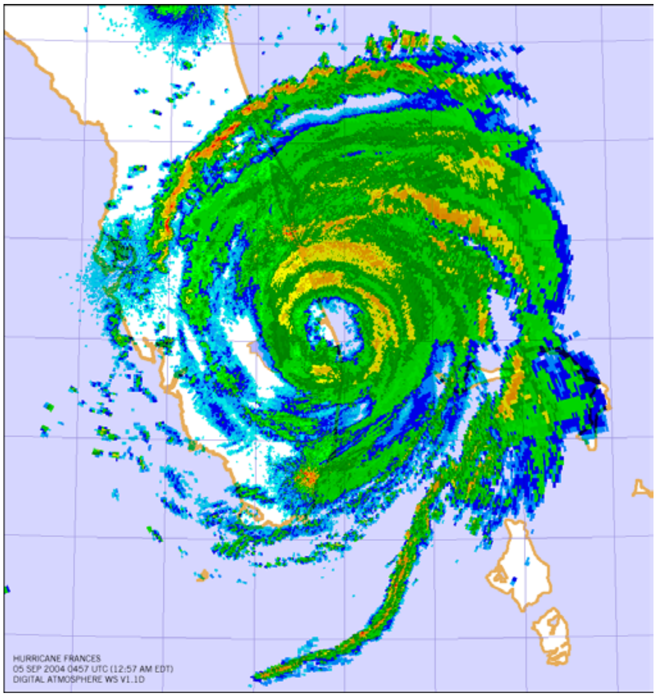
3.1.2 Precipitating event

By virtue of its location, the state of Florida is exposed to tropical storms and hurricanes, so electric utilities operating in this region have significant experience in coping with these weather events. Over the past several decades, hurricane severity and coastal-area population and economic development have increased. Consequently, both the physical impacts of these hurricanes and the economic impacts of associated power interruptions have become more severe. Hurricane Andrew (1992) was the first Category 5 storm to hit the state since 1935. Subsequently, in the 2004-2005 seasons, one Category 4 and four Category 3 hurricanes made landfall in Florida.[10]

The 2005 hurricanes were especially severe and damaging. Hurricane Katrina on August 25-26 interrupted power across 15 counties in FPL's service territory, affecting 1.5 million – about one-third – of FPL's customers. Power was restored to 77% of customers by the third day following the storm, 95% by the fifth day, and all customers by the eighth. Hurricane Wilma hit Florida on October 25, and interrupted power to more than 3 million – 75% – of FPL's customers across 21 counties. In Miami-Dade, Broward, and Palm Beach counties, 91% of customers lost power. At the time, this was the most damaging storm in the utility's history, affecting power plants, transmission lines, and substations as well as distribution facilities. Power was restored to more than 1 million customers by the third day after the storm, 2 million by the fifth day, 3 million by the thirteenth, and all customers by the eighteenth.

[10] More recently, Hurricane Matthew (2016) primarily affected the state's coastline, but the Category 4 Hurricanes Irma and Michael in 2017 and 2018, respectively, passed over inland areas and had significant impacts.

Figure 3-1. Hurricane Frances making landfall in Florida in 2004 (Wikimedia Commons 2004)



3.1.3 Regulatory and policy responses

The physical and economic impacts of the 2004-2005 hurricane seasons prompted a comprehensive re-evaluation of utility rules and practices in Florida, including both the engineering and economic aspects of hurricane preparation and response. This response was an effort by multiple stakeholders including the FPSC, FPL (and other utilities), state legislature, private sector, universities, and utility customers. Between 2005 and 2007, proposals were developed to update utility operations and planning, applicable regulations and laws, and procedures for preparing for – and recovering from – severe storms. Specifically, these efforts included the mechanisms for the state's utilities to recover the costs of (1) storm hardening (i.e., engineering measures to increase the capacity of the electric power system to withstand storms) and (2) addressing storm-related damage to utility infrastructure. These elements were codified into specific recommendations to the FPSC for a set of new initiatives and processes to achieve (and maintain) a higher level of preparation for severe hurricanes. Following an extensive review, the FPSC adopted these recommendations in 2006, and the state legislature concurrently passed new legislation pertaining to storm hardening and cost recovery (FPSC 2005, 2006, 2007a, 2007b; FAC 2006a, 2006b). Additional information is provided in the following section.

Table 3-1. Chronology of Florida storms, regulatory responses, and utility activities

Time frame	*Event and activity*
2004-2005	● Five severe hurricanes impact Florida. ● FPL files cost recovery petition for 2004 hurricanes. ● FPSC reviews and amends method for utility cost recovery related to storms and approves modified cost recovery. ● FPL files petition for recovery of costs of 2005 hurricanes.
2006	● FPSC approves cost recovery for 2005 hurricanes. ● Multi-stakeholder workshop develops proposals for revising storm-hardening rules and procedures. ● FPSC institutes new rules for expanded, ongoing hardening activities by utilities.
2007	● FPL files first triennial storm-hardening plan under new rules. ● FPSC reports to state legislature on storm preparation.
2008	● Report is released for Florida electric utilities on storm-hardening cost-benefit tool (ex-ante perspective). ● FPSC submits follow-up legislative report.
2009-2015	● FPL files triennial storm-hardening plans in 2010 and 2013.
2016	● FPL files 2016-2018 storm-hardening plan. ● Hurricane Matthew impacts Florida. ● FPL files Hurricane Matthew-related cost recovery petition.
2017-2018	● Hurricane Irma impacts Florida. ● FPSC holds workshop discussing utility storm-preparedness status; issues report. ● FPL begins 2019-2021 storm-hardening planning.
2019	● Florida state legislature enacts expanded requirements for utility storm-hardening and cost recovery Senate Bill 796, “Public Utility Storm Protection Plans.”
2020	● FPSC passes rules to implement Senate Bill 796 requirements. ● FPL submits 10-year storm protection plan under new rules.

3.2 Event response and immediate recovery

Engineering and operational elements

FPL reports hurricane impacts on its infrastructure and equipment in a number of categories, as illustrated in its report for Hurricane Irma in 2017 (FPL 2018). The categories include:

1. General—storm characteristics and vegetation impacts
2. Transmission and substation impacts
3. Distribution system impacts
4. Smart Grid—automated feeder switch performance impacts
5. Detailed vegetation impacts
6. Restoration statistics and comparisons with previous storms

The reports contain high levels of detail for these categories of impact.   For more information, see the Technical Appendix.

Cost recovery
Historically, FPL and other Florida (and Southeast) utilities purchased hazard insurance on the commercial market that covered losses from hurricane-related damage. Following Hurricane Andrew (1992), however, this type of insurance became generally (although not completely) unaffordable. Consequently, FPL and other utilities shifted primarily to a self-insurance strategy and built up reserve accounts against losses from unusually severe storms.   This approach became infeasible with the 2004-2005 storm seasons when unusually severe hurricanes not only exhausted FPL's reserves, but also resulted in hundreds of millions of dollars in unforeseen costs. Although the utilities still maintain reserve accounts, the funds are not intended to defray the costs of (what have historically been) infrequent but unusually severe storms. One element of the regulatory changes in 2006 was a new provision allowing Florida investor-owned utilities to apply for recovery (from ratepayers) of costs incurred for restoring power following storms. The key principle governing this cost recovery is the "Incremental Cost and Capitalization Approach (ICCA)," stipulated in Florida Rule 25-6.0143, which requires that utilities may recover only costs that are incremental to those that the utility would charge under non-storm circumstances (FAC 2006a).

Categories of expenses: FPL reports costs and expenses in the following categories: payroll (regular and overtime), contractors, line clearing (i.e., of vegetation and other debris), vehicles and fuel, materials and supplies, logistics, property damage, and other. These costs are, in turn, broken out across infrastructure type and function: steam and other thermal power plants, nuclear plants, transmission system, distribution system, customer service, and a "general" category for utility internal management and other expenses in support of recovery and restoration activities (FPL 2016b).

Accounting procedures: The expense categories noted above reflect regulatory requirements. In addition, the utility is subject to the ICCA incremental cost criterion noted above. Within these constraints, FPL's storm-cost accounting follows the Financial Standards Accounting Board's Accounting Standards Codification 450, which prescribes that losses must have occurred at the reporting date and that their amounts can be reasonably estimated.

Methods and techniques to estimate costs to utilities: In a petition for storm cost recovery, FPL reports actual costs incurred, as tracked by its internal accounting systems. These charges are recorded under the Federal Energy Regulatory Commission (FERC) Account 186, "Miscellaneous Deferred Debits." Under the law the utility may submit comprehensive initial estimates with the proviso that updates and adjustments may be made as final information is collected. Initial estimates are then subject to a "true-up" adjustment.

Quality, accuracy, and reliability of estimates: As noted above, FPL's petitions for storm cost recovery are reviewed, considered, and adjudicated in adversarial regulatory hearings. After the proceedings for the 2004-2005 storm seasons, Florida and FPL did not experience another severe storm until Hurricane

Matthew in 2016. The utility's petition for cost recovery for responding to Hurricane Matthew, and the review of that petition, exemplify how FPL's estimates are carefully scrutinized and are questioned and challenged during the regulatory process, and the Commission, its staff, and interveners propose revised estimates that are typically lower than FPL's (FPL 2016b). The regulatory records of cost recovery dockets examine several aspects of the quality, accuracy, and reliability of the utility's estimates. First, "raw" estimates (i.e., actual expenditures) are in some cases questioned, usually on the basis of insufficient detail having been provided. In such cases, the utility either disputes the claim or provides further detail. Second, interveners question the appropriateness of the accounting of estimated costs in terms of, for example, correct assignment to accounting categories and/or eligibility under relevant regulations and Commission decisions. The documentation indicates that this adversarial process results in the utility's estimated and final reported costs meeting a fairly high standard of quality, accuracy, and reliability.

Availability of documentation: Extensive documentation is available on the FPSC website regarding FPL's storm recovery costs and the scrutiny and review of the utility's reported costs during the regulatory process. Table 3-2 details the general availability of economics-related information related to cost recovery.

Table 3-2. Availability of economic information related to cost recovery

Utility	Precipitating Event	Trans. System Costs	Dist. System Costs	Gen. System Costs	Increased Customer Service Costs	Other Costs	Comments
Florida Power & Light	Hurricanes of 2004-2005	●	●	●	●	●	"Other" costs include utility internal management and other expenses in support of recovery and restoration activities.

Cost recovery request and outcome

In November 2004, FPL reported to the FPSC that in the recovery and restoration following that year's hurricanes it had incurred "extraordinary" costs of about $710 million net of insurance, leaving a $356 million deficit in its storm reserve fund. In March 2005, it revised the cost estimate to $890 million, leaving a $533 million deficit. In September of that same year, the FPSC approved the petition but introduced a new methodology for cost-recovery calculations; applying this methodology, the Commission decided to allow FPL to recover $442 million from its customers in a surcharge over three years.

In January 2006, FPL requested that the FPSC approve recovery of $1.05 billion to cover the remaining balance of its 2004 restoration costs and $827 million in costs for the 2005 hurricane, including replenishment of its storm cost reserve. The Commission approved the issuance of cost recovery bonds for this amount, using a securitization process, in May 2006.

3.3 Preparing for the future

Upgrading infrastructure, maintenance, and readiness standards

Since 2006, FPL and other utilities have been required to develop and submit storm-hardening plans for FPSC review on a three-year cycle, pursuant to Rule 25-6.0342 of the Florida Administrative Code. The rule requires that plans "…contain a detailed description of the construction standards, policies, practices, and procedures employed to enhance the reliability of overhead and underground electrical transmission distribution facilities." The utilities became subject to stricter storm-hardening standards for both their infrastructure and their maintenance, including for ongoing vegetation clearing, among other requirements. These provisions include compliance with a specified National Electrical Safety Code (NESC) standard and the adoption of NESC's extreme wind loading standards. The rule requires that utility hardening plans contain details of utilities' deployment plans for meeting these and other requirements, as well as attachment standards and procedures for transmission and distribution poles.

In 2006, FPSC in Order 06-0351 instituted the 25-6.0342 requirements (FPSC 2006), which mandate wood pole inspection (and, as needed, replacement) on an eight-year cycle, and the following 10 initiatives:

1. Three-year vegetation management cycle for distribution circuits
2. Joint-use attachment agreements
3. Six-year transmission structure inspection program
4. Existing transmission structure hardening
5. Transmission and distribution geographic information system
6. Post-storm data collection and forensic analysis
7. Detailed outage data collection, differentiating between the reliability performance of overhead and underground systems
8. Increased utility coordination with local governments
9. Collaborative research on effects of hurricane winds and storm surge
10. Natural disaster preparedness and recovery program

FPL's plans provide detail on engineering, equipment, location of measures, and other aspects documenting its compliance with the new requirements. For example, between 2007 and 2012 the utility replaced more than 4,000 wood transmission structures with concrete structures. In addition, FPL upgraded more than 3,600 ceramic post insulators with a polymer material that is able to withstand more extreme types of weather than the ceramic components.[11] (See also FPL 2007, 2010, 2013, 2016a, and the Technical Appendix for further details).

Economic benefits—*avoided customer interruption costs*

The aforementioned Florida state Rule 25-6.0342 requires that storm-hardening measures and actions be "cost-effective" and that utility plans include "an estimate of the costs and benefits to the utility…of

[11] Adapted from news release, see: https://www.transmissionhub.com/articles/2013/05/fpl-to-replace-up-to-approximately-1600-transmission-structures-through-2015.html

making the electric infrastructure improvements, including the effect on reducing storm restoration costs and customer outages." Along with proposed engineering-related measures, FPL's triennial storm-hardening plans include estimates of the expenditures needed to implement them (FPL 2007, 2010, 2013, 2016a).

Methods and techniques to estimate customer costs: FPL reports estimated customer costs of hurricane-caused power interruptions indirectly, in petitions for storm hardening rather than in petitions for cost recovery. Customer costs are presented as estimated benefits; in effect, they are avoided customer interruption costs that would result from proposed storm-hardening investments. To date, the utility has not quantitatively estimated these values, citing unavailability of this information. Instead, the utility provides *qualitative* descriptions of customer benefits and cites estimated reductions in restoration costs that will result from storm-hardening investments. The following statements appeared in each of FPL's 2007, 2010, 2013, and 2016 storm-hardening plans.

> While there are clear benefits from FPL's storm-hardening and preparedness initiatives, it still remains nearly impossible at this time to estimate the full extent of the benefits with any precision…FPL has estimated that, over an analytical study period of 30 years, the net present value of Restoration Cost Savings per mile of hardened feeder would be approximately 45% to 70% of the cost to harden that mile of feeder for future major storm frequencies in the range of once every three to five years.

In addition, the following statements appeared in each of the plans beginning in 2010:

> It is also important to note that, in addition to Restoration Cost Savings, customers will benefit substantially, in many direct and indirect ways, from the reduced number and duration of storm and non-storm outages resulting from the planned hardening activities. FPL expects that they vary substantially from customer to customer, and FPL is not in a position to assign monetary value to them.

FPL has emphasized that the Florida Administrative Code Rule 25-6.0342 stipulates cost-*effectiveness* analysis as an appropriate criterion to evaluate storm preparedness measures—i.e., as opposed to cost-*benefit analysis*. In the most recent cycle, FPL noted that the 2016-2018 plan was "…cost-effective, at many levels."

Quality, accuracy, and reliability of estimates: FPL has not submitted details of cost-effectiveness analyses of its storm-hardening plans. The details of the plans have been reviewed and debated in a fashion similar to the storm-cost-recovery petitions mentioned above. Since 2006, FPSC has not questioned the utility's estimates, has accepted that the absence of data precludes quantitative estimation of customer benefits from storm preparation, and has approved FPL's actions on the basis of technical soundness and compliance with regulatory requirements. Nonetheless, the quality, accuracy, and reliability of these estimates remain to be determined.

Availability of documentation: In addition to the absence of cost-effectiveness documentation, there is also little or no information in the Florida regulatory record documenting the restoration cost-savings estimates described above.

Economic benefits—*avoided regional economic impacts*

Although numerous studies have been conducted of both the direct and indirect economic impacts of recent hurricanes on the Florida economy, including key sectors, we have not identified any studies of the avoided, indirect impacts resulting from event-preparedness activities.

Methods and techniques to estimate regional economy-wide impacts: N/A

Quality, accuracy, and reliability of estimates: N/A

Availability of documentation: N/A

Economic benefits—o*ther avoided societal impacts*

We were unable to find information on avoided societal impacts from storm preparedness.

Methods and techniques to estimate other avoided societal impacts: N/A

Quality, accuracy, and reliability of estimates: N/A

Availability of documentation: N/A

Table 3-3 details the general availability of information on the economics of event preparedness, including whether this information was used (1) to supplement a CEA or (2) in a formal CBA.

Table 3-3. Availability of economic information related to mitigating future customer and regional impacts

Organization	Precipitating Event	Avoided Customer Interruption Costs	Avoided Regional Economic Impacts	Other Avoided Societal Impacts	Other	Cost-Effectiveness Analysis?	Cost-Benefit Analysis?	Comments
Florida Power & Light	Hurricanes of 2004-2005	○	○	○	○	**Yes**	**No**	“Other” category includes utility estimates of net present value of restoration cost savings per mile of hardened feeder; little or no documentation available on method to estimate the restoration cost savings.

3.4 Discussion

Public utilities commission process for preparedness and response planning

Because FPL is a regulated, investor-owned utility, all of its proposed measures and expenditures related to both storm hardening and storm cost recovery must be approved by FPSC. The specific regulatory proceedings for this purpose are referred to as "dockets." FPL requests approval of storm-hardening engineering plans and associated investments in dedicated dockets, with financial aspects of the plans proposed, evaluated, and decided upon by the FPSC in general rate cases where there are hearings on several dockets simultaneously. These are adversarial processes in which multiple stakeholders participate in addition to the regulators, their staff, and the utility (subject to approval of standing). Florida citizens and ratepayers are represented by the state's Office of Public Counsel; non-governmental organizations participate, as do groups representing different segments of industry, and private individuals. As a rule, most, but not all, non-utility participants oppose FPL's financial requests for various reasons (see further details below). FPSC adjudicates this process and decides the merits of all parties' opinions and proposals. In some cases, direct negotiations between FPL and other parties result in a compromise (called a "settlement") that is proposed to the Commission. In all cases, the Commission makes the final, binding decision.

How the findings relate to previous work

Several aspects of Florida's record are important to highlight in relation to work on resilience discussed in Section 2. First, although the term "resilience" is sometimes mentioned informally in the regulatory record by FPL and other stakeholders, resilience *per se* is not formally recognized or used either as a concept or as an operational criterion by the utility or the regulator in Florida's storm-hardening planning or storm impact analysis and recovery. Florida does not single out "resilience investments" as a special category. Second, the agreed-upon metrics for measuring storm impacts are well understood by all parties and are specific physical and/or engineering quantities pertaining to electricity infrastructure; there are no special "resilience metrics," nor is there an apparent need for any. These facts are illustrated, for example, by the detailed categories that FPL uses to report storm damage impacts and by the categories in FPL's storm-hardening plans. This has implications for any effort that might be undertaken, in Florida at least, to implement the National Academies' recommendation for operationalizing metrics that have been developed elsewhere. Third, storm cost-recovery and the costs of storm hardening are considered separately in the regulatory process, rather than, for example, directly compared in order to estimate the relative costs and benefits of ex-ante hardening investments vs. ex-post recovery measures. This has implications for how to design and implement research on tools and methods for analyzing the cost-benefit trade-offs between the two.

Additional commentary on economic data and methods

As noted above, FPL does not have information or methods to estimate the direct (or indirect) costs of power interruptions to its customers. However, a collaborative research project on improving hurricane preparation was started in 2006-2007 involving the University of Florida, the state's utilities, regulators, and other stakeholders. One component of this project was development of a modeling tool for estimating the costs and benefits of storm hardening and other power-interruption preventive measures (Brown 2008). This tool was linked to a simple hurricane simulation model that provided scenario inputs for hurricanes of different intensities and impacts. The tool was designed to quantify customer benefits of measures to prevent power interruptions using estimates of direct costs based on standard reliability measures such as system average interruption frequency index (SAIFI) and system average interruption duration index (SAIDI). Survey data were the intended source of these estimates, with costs of backup generation as an upper bound. However, these data were not developed or entered into the model, and this cost-benefit tool was not adopted by FPL or other Florida utilities in the subsequent years. One reason is that, following the 2004-2005 hurricanes, there was not another major storm until 2017; therefore, no empirical data were collected during this period on actual benefits from hardening and other measures.

Following the severe impacts of Hurricanes Michael and Irma in 2017-2018, FPSC engaged its regulated utilities and others in assessing the benefits of storm-hardening efforts over the preceding decade in terms of reduced damage to electricity infrastructure and reduced numbers and durations of power interruptions (FPSC 2018). Although a formal CBA was not conducted, it was found that the performance of the system was substantially improved compared to performance during previous severe hurricanes. At the same time, FPSC staff recommended that, from then on, utilities be required to explicitly compare the effects, costs, and benefits of storm-hardening measures vs. storm restoration actions. For reasons discussed above, information currently available to make such comparisons is limited. In its March 2019 petition to FPSC for approval of its 2019-2021 storm-hardening plan, FPL used language identical to that used in previous plans, to the effect that the utility is unable to quantify customer benefits of proposed investments and measures (FPL 2019).

In June 2019 the Florida state legislature passed Senate Bill (SB) 796, "Public Utility Storm Protection Plans," which included Section 366.96, Florida statutes, expanding the requirements for electricity transmission and distribution system storm hardening and amending the rules for cost recovery of electric utilities' hardening expenditures. In January 2020 FPSC adopted two rules to implement these requirements, 25-6.030, F.A.C., Storm Protection Plan, and 25-6.031, F.A.C., Storm Protection Plan Recovery Clause.

Section 366.96 stipulates, among other things, that storm protection plans must consider "the estimated costs and benefits to the utility and its customers of making the improvements proposed in the plan." Section 25-6.030 states that these plans must include:

> A description of how implementation of the proposed Storm Protection Plan will reduce restoration costs and outage times associated with extreme weather conditions therefore improving overall service reliability.
>
> A description of how each proposed storm protection program is designed to enhance the utility's existing transmission and distribution facilities including an estimate of the resulting reduction in outage times and restoration costs due to extreme weather conditions.

A cost estimate including capital and operating expenses.

A comparison of [these] costs…and the benefits [of reductions in outage times and restoration costs].[12]

The last provision does not say how these benefits should be quantified. As in previous years, FPL's first storm protection plan filed under the new rules proposes measures including pole inspections, feeder hardening, undergrounding, and vegetation management, and provides detailed engineering data and cost estimates for each, down to the individual project level. It also compares equipment and/or infrastructure performance in each category pre- and post- hardening and hurricanes, including the improvement in outcomes (reduced numbers of failures and/or outages) from Hurricanes Wilma (2005) and Matthew (2007) to Irma (2017). Moreover, it uses a storm damage simulation model to project the long-run cost restoration cost savings from storm hardening prior to Matthew and Irma. This model compares future hypothetical storm impacts with and without these previous measures over a 40-year time horizon and the corresponding net present value of reduced restoration costs. (This is done for broad categories of hardening, not individual projects).

In summary: Under Florida's recently revised rules for electricity transmission and distribution storm hardening, utilities can estimate benefits to customers in terms of reduced storm-induced outage and restoration times, and benefits to the utility in terms of estimated future restoration cost savings. Utilities are not required to estimate or report avoided customer costs as such.

[12] These four provisions are items (3)(b), (3)(d)1., and (3)(d)3., and (3)(d)4., respectively, in FPSC (2020).

4. New York

4.1 Background information

4.1.1 Utility and regulatory body

Consolidated Edison of New York, Inc. (Con Ed) is a regulated, investor-owned utility providing electricity, natural gas, and steam heat to New York City and Westchester County.[13] Originating as the New York Gas Light Company in 1823, the utility began providing electricity service in 1882 with the establishment of Thomas Edison's Edison Illuminating Company, which built the world's first centralized electric power system, serving lower Manhattan (NYC 2013, Chapter 6). The Consolidated Edison name was adopted in the 1930s, by which time electricity predominated in company energy sales and distribution. Today, the company serves approximately 10 million residents and businesses in its service territory.

Con Ed is regulated by the New York (state) Public Service Commission (NYPSC, which is authorized by state law to oversee the production, sale, and distribution of electricity, natural gas, and steam throughout New York State, and to regulate rates for these energy services.[14] Regulation and oversight are in accordance with the New York Codes, Rules and Regulations Title 16, which pertains to Department of Public Service, Chapter II provisions for electric utilities.

4.1.2 Precipitating event

Tropical Storm Sandy formed in the Caribbean in late October 2012.[15] Over the following week, it traveled north, crossing Jamaica, Cuba, and the Bahamas, intensifying to a Category 3 hurricane along the way, and then turning in a northeasterly direction, paralleling the U.S. eastern seaboard. Next, it turned west and made landfall near Atlantic City, New Jersey, on October 29. By that time, Sandy's wind speeds had decreased to 80 miles per hour but were still above the hurricane-classification threshold of 74 miles per hour. Although the storm was reclassified as a post-tropical cyclone because it lacked other characteristics of a hurricane (including no longer having an "eye"), several factors combined to cause severe impacts. Upon landfall, Sandy's tropical-storm-magnitude winds extended for 1,000 miles, an area several times greater than that affected by most hurricanes. In addition, the storm's landfall coincided with an extremely high tide. These factors, along with the storm's perpendicular angle of arrival on the coast, resulted in unprecedented storm surges and flooding in and around New York City. At the Battery in Lower Manhattan, the surge, or storm tide, was a record 14 feet (measured above the average low tide level). Nearly 20% of the city's land area was flooded, exceeding the "100-year" floodplain boundaries designated by Federal Emergency Management Agency (FEMA) maps by nearly 50%.

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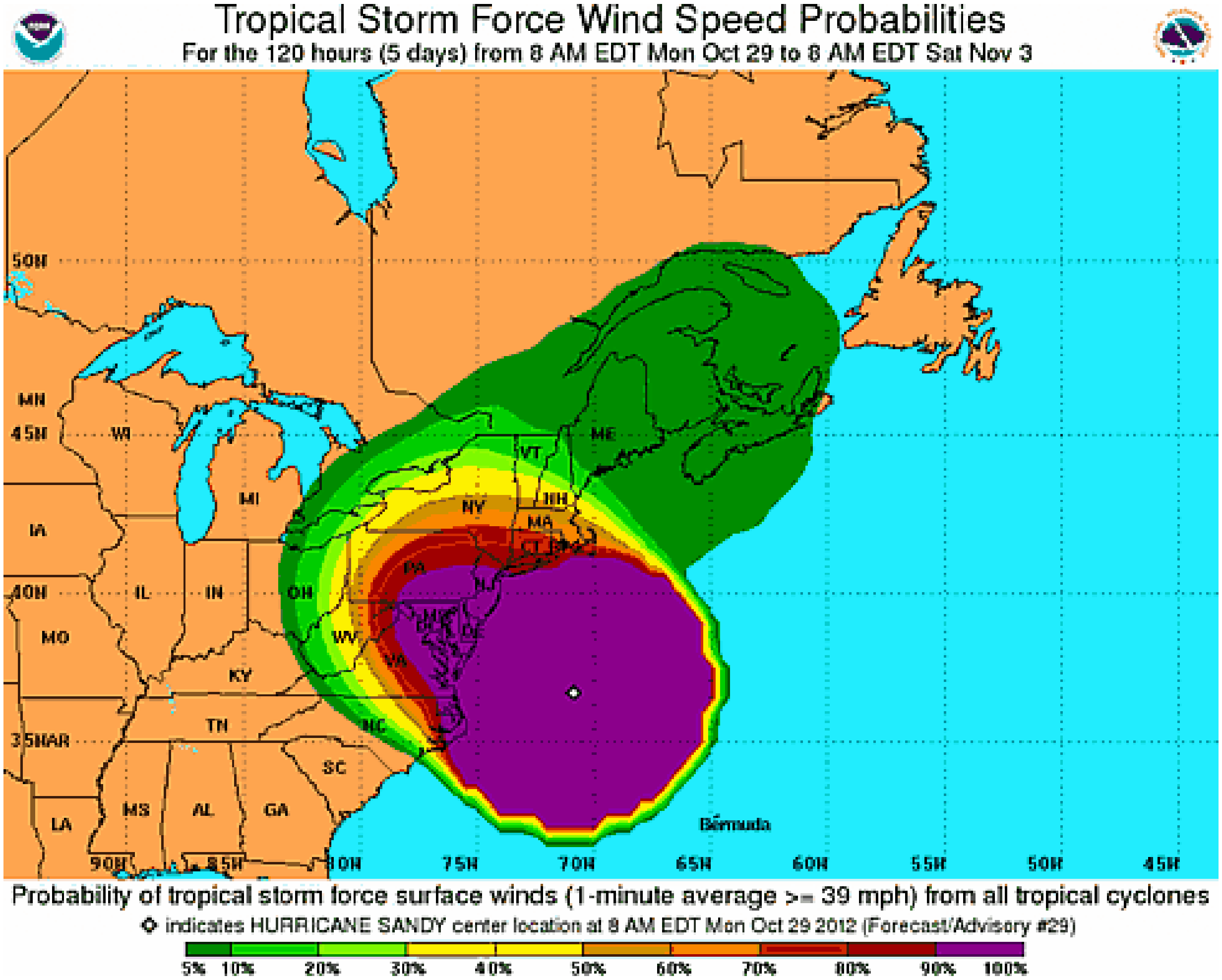
[13] Con Ed serves about 99% of electricity customers in New York City; the Rockaway Queens area is served by the Long Island Power Authority.

[14] In NYPSC (2014), the commission cited New York Public Service Law Sections 5(1)(b), (c); 66(1); 80; 65(1); 79(1), as the bases for its authority.

[15] This section draws on NYC (2013), Chapter 1.

Figure 4-1. Tropical storm Sandy wind speed probabilities (Fairfax Office of Emergency Management 2012)



Con Ed monitored the storm prior to its arrival and made preparations, but the storm surge was several feet higher than predicted by the National Weather Service even on the morning of landfall. The resulting flooding shut down numerous substations and networks (see Section 4.2 below). More than 2 million people lost power, including two-thirds of those served by overhead systems affected by wind and fallen-vegetation damage. Power was restored to 50% of affected customers within three days, 90% within eight days, and all remaining customers who could accept service within 13 days (NYC 2013, Chapter 6, Con Ed 2013a).

4.1.3 Regulatory and policy responses

NYPSC and other agencies responded strongly and comprehensively to the impacts of Sandy and the manner in which Con Ed responded to and recovered from the storm. In 2013, following a recommendation of its staff policy panel, the NYPSC ordered the creation of the "Storm Hardening and Resiliency Collaborative" in the context of a Con Ed rate case initiated that year. This multi-stakeholder initiative was charged with reviewing the utility's storm preparedness and storm-hardening proposals and the hardening design standards for the Con Ed system, studying the possible incorporation of potential climate change impacts into these standards, and making recommendations related to these issues (Con Ed 2013d, 2014). Over the following three years, the Collaborative undertook these activities, also studying risk analysis and CBA for resiliency projects, as well as alternative hardening strategies such as microgrids, among other topics (Con Ed 2015a, 2015b) REF LIST HAS 2015a and b.[16] The Collaborative's basic recommendations were contained in a consensus "Joint Proposal," developed and negotiated by its members and filed with the NYPSC in December 2013 as its "Phase One" report (Con Ed 2013d). The NYPSC subsequently noted that "…there is broad support among the parties for these capital investments that are intended to enhance the reliability and resiliency of Con Edison's system" (NYPSC 2014). The Joint Proposal, and subsequent recommendations of the Collaborative, were intensively reviewed, discussed, and, as needed, amended, during Con Ed rate case proceedings, and adopted by the NYPSC with certain modifications in February 2014 (NYPSC 2014, 2015, 2016).[17]

Another outcome of this process was a climate-change vulnerability study, which was proposed by the Collaborative and ordered by the NYPSC in 2014. The study was to review relevant climate-change science, assess its implications for future extreme weather impacts on Con Ed's system and design standards for mitigating them, and develop appropriate risk mitigation options. The study was conducted by Con Ed with the input and collaboration of a number of stakeholders and was completed in December 2019. During this period the City of New York government undertook extensive activities to assess and address the risks of climate change, including increasing the resilience of city facilities and critical infrastructure to the effects of sea-level rise.[18]

Table 4-1. Timeline of storms, regulatory responses, and utility activities

Time frame	*Event and activity*
2012	● Tropical storm Sandy impacts New York City and U.S. eastern seaboard in late October.
2013	● NYPSC orders creation of Resiliency Collaborative. ● Con Ed submits Sandy preparation and recovery report, post-Sandy resilience enhancement plan, and incremental cost reports to NYPSC. ● Resiliency Collaborative Phase One report is released.
2014	● NYPSC approves Con Ed Sandy cost-recovery request. ● NYPSC approves Resiliency Collaborative Phase one recommendations (as stipulated in proposed joint agreement). ● Resiliency Collaborative Phase Two report is released and adopted by NYPSC.
2015	● Resiliency Collaborative Phase Three report is released.

[16]To conduct these studies, the collaborative was organized into four working groups: (1) Storm-Hardening Design Standards and 2014 Projects, (2) Alternative Resiliency Strategies, (3) Natural Gas System Resiliency, and (4) Risk Assessment/Cost Benefit. The Collaborative comprised 16 participants in addition to Con Ed, including several New York state government offices and agencies, the City of New York and the County of Westchester, three academic centers or departments from area universities, several consumer advocacy groups, a private consulting firm, and a local union.
[17] The Collaborative concluded its work in January 2016.
[18] For New York City's projects and programs see: https://www1.nyc.gov/site/cpp/index.page.

2016	• Phase Three report is adopted by NYPSC.
2019	• Con Ed Climate Change Vulnerability Study is released.

4.2 Event response and immediate recovery

Engineering and economic elements

New York state law requires that electric utility companies report to the NYPSC on their preparation[19] and recovery performance following any power interruption that entails service restoration times of more than 72 hours.[20] The law also stipulates that expenditures on recovery and restoration from power interruptions must be reported to the NYPSC for review and are approved at the Commission's discretion, according to general criteria established in state law.

Con Ed submitted a report on Sandy to the NYPSC in January 2013 (Con Ed 2013a). The utility described its monitoring of Sandy in the days before landfall and the utility's activities to anticipate and mitigate potential impacts on its system. The report documented "four major outage incidents" resulting from the storm: (1) pre-emptive shutdown of several local distribution networks in lower Manhattan and one in Brooklyn to prevent flood damage; (2) automatic shutdowns of 11 networks in Manhattan because of flooding; (3) automatic shutdown of three load areas on Staten Island because of flooding and wind damage at two transmission substations; and (4) widespread customer power interruptions because of the impact of sustained high winds and gusts on radial overhead distribution lines. Con Ed's report included detailed location- and facility-specific descriptions of these incidents and the utility's response. The report also provided detailed information on the locations and durations of power interruptions to customers. Table A-1 in the Technical Appendix contains a list of the contents of the utility's Sandy preparation and response report.

Cost recovery

Categories of expenses: In July 2013, Con Ed filed a report to the NYPSC on the utility's costs for Sandy response and recovery as of May 2013 (Con Ed 2013c). These were incremental O&M costs, i.e., they would not have been directly incurred in the absence of the storm (although some might have been incurred over time in the course of Con Ed's routine operations). The report divides these costs into four broad categories: (1) contract services, (2) company labor, (3) materials & supplies, and (4) other, which includes employee expenses and equipment rentals. Table A-2 in the technical appendix provides detail on reported costs within each of these categories.

Accounting procedures: No specific accounting procedures were reported beyond the categorization scheme used to report the costs.

[19] Here, "preparation" means in the hours or days immediately preceding the event, which is assumed to be a storm or hurricane.

[20] 16 New York Codes, Rules and Regulations Part 105.4(c).

Methods and techniques to estimate costs to utilities: Although the documentation reviewed in this case study did not describe any particular methods or techniques, we presume that the costs were estimated using Con Ed's standard internal cost accounting process.

Quality, accuracy, and reliability of estimates: The available documentation does not provide sufficient information to evaluate the quality, accuracy, or reliability of the estimates. However, the utility had to satisfy its regulators on these points, and the Commission would have reviewed and scrutinized the estimates before approving or disallowing them.

Availability of documentation: Names of individual vendors and amounts paid for contract services were included; Con Ed indicated that "extensive additional detail for Staff audit" was available (i.e., to regulators). According to a July 29, 2013 Con Ed letter to NYPSC, the "additional detail" comprised 24 megabytes of information. Rather than submit a complete hard copy, the company proposed working with staff to facilitate thorough review. Although this information is not readily available to the public, it was available to regulatory staff. Table 4-2 summarizes the availability of economic information associated with cost recovery after Tropical Storm Sandy.

Table 4-2. Availability of economic information related to cost recovery

Utility	Precipitating Event	Trans. System Costs	Dist. System Costs	Gen. System Costs	Increased Customer Service Costs	Other Costs	Comments
Consolidated Edison	Tropical Storm Sandy	●	●	●	●	●	"Other" category includes employee expenses and equipment rentals.

Cost-recovery request and outcome

In the July 2013 filing with the NYPSC noted above, Con Ed reported $254 million in costs associated with recovery from Sandy. In February 2014, NYPSC approved recovery through rate increases of $247 million of these costs in the context of settlement the utility's general rate case at that time. The $7 million difference does not appear to be explained in the documentation available online. This settlement also included funding for implementing the abovementioned new program of expanded and increased storm hardening, developed by Con Ed and other stakeholders; we provide further details in the next section.

4.3 Preparing for the future

Upgrading infrastructure, maintenance, and readiness standards

New York State law has long required that Con Ed and other New York utilities have emergency response and restoration plans in place.[21] According to its Post Sandy Enhancement Plan (Con Ed 2013b), Con Ed replaced 1,500 utility poles and 1,380 transformers in the aftermath of the storm. Con Ed began developing more extensive plans to improve its storm preparedness immediately following Sandy (Con Ed 2013b). As we noted above, Con Ed's overall resiliency plan was developed and proposed in collaboration with a multi-stakeholder group. In approving this group's 2013 Joint Proposal on resiliency, NYPSC described its review criteria as follows:

> In reviewing a joint proposal, we consider: consistency with law and policy; whether the outcomes are reasonably within the range of likely outcomes of a fully litigated proceeding; the balance of ratepayer, investor, and long-term interests; and whether the joint proposal and accompanying record represent a rational basis for decision.[22]

The Commission concluded that "…the rates, terms, and provisions of the Joint Proposal strike a proper balance between the interests of the customers and investors."

With the approval of this proposal, Con Ed undertook a multi-year effort to protect and harden its infrastructure through relocation and/or strengthening of equipment to prevent and mitigate flooding and wind damage, to mitigate severe storm impacts by increasing system flexibility through advanced control, and to promptly identify damaged parts of the system in order to facilitate restoration. This work was carried out in consultation with, and drawing upon input from, the Resiliency Collaborative, which in its first phase formed working groups and focused on particular aspects of resiliency planning and preparation. The Collaborative defined a "resilience- or storm hardening- capital project [as] a project that is undertaken in whole or in part to strengthen Con Ed's infrastructure to withstand or recover from extreme weather-induced impacts" (NYPSC 2013). The major new design and hardening criterion that was developed and adopted is a standard requiring that the Con Ed system be resilient to flooding based on FEMA's one-percent annual flood hazard elevation (100-year floodplain) in the utility's service territory, plus a minimum additional three feet, which exceeds the New York City Building Code requirements.

Con Ed and the collaborative parties proposed and developed appropriate levels of hardening improvement on a case-by-case basis for all system components, including substations, network distribution, overhead distribution, and generating equipment (as well as for the utility's gas and steam infrastructure). For substations, the measures included installing fiber-optic cable, above-flood-control -level emergency diesel generators, moat walls, and high-capacity flood control pumps. The network distribution system measures included submersible transformers (e.g., replacements of all 120/208-volt

[21] 16 New York Codes, Rules and Regulations Part 105.4(c).

[22] For these considerations the Commission cited its Case 90-M-0255, Proceeding on Settlement Procedures and Guidelines, Opinion No. 92-2, 1992.

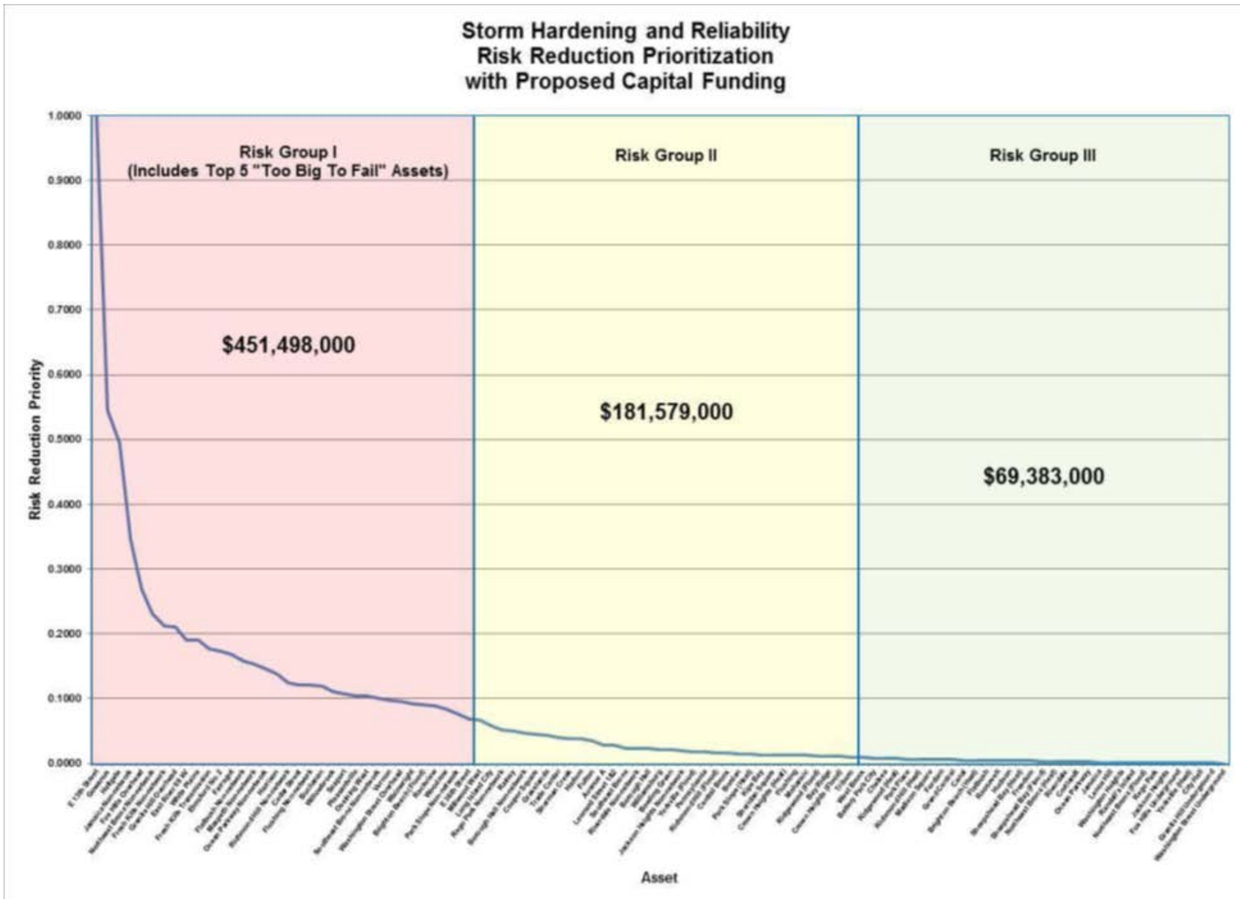
transformers in New York City Flood Zones 1 and 2) and submersible network protectors (e.g., new 460-volt services built to protect installations from saltwater in Zones 1 and 2). For the overhead electricity distribution system, measures included installing additional reclosers and sectionalizing switches, improving auto-loop circuit reliability by upgrading poles and cables, undergrounding select portions of the network, and enhancing vegetation management. These and other measures were carefully reviewed by NYPSC staff and other stakeholders during the rate cases, amended as necessary, and ultimately decided upon by the Commission.

Economic benefits—*avoided customer interruption costs*

With respect to preparing for extreme weather events by undertaking resilience measures and investments, NYPSC ordered in 2014 that "…Con Ed will continue the development and expansion of its risk assessment model with the participation of Collaborative parties, as well as a cost-benefit model…applicable both to the utility storm hardening and to alternative resilience approaches" (NYPSC 2014). In the Collaborative's reports and in rate case filings, Con Ed submitted detailed cost estimates for the large number individual projects it proposed to enhance resiliency using its risk assessment and cost-benefit tools, as described below.

Con Ed estimates VOLL using an analytical framework and method for evaluating the costs and benefits of resilience investments. These evaluations proceed in two steps. First, the utility uses a "Risk Assessment and Prioritization" model that it developed prior to Sandy and has further developed and refined since, which is designed for and applied to analyzing the risks of power interruptions caused by either flooding or wind. The inputs to the risk calculation are (1) the number of customers affected by a power interruption, (2) the type of infrastructure or equipment affected, and (3) the duration of the interruption. Estimates are made for substations, underground facilities, and overhead facilities. Within each of these groups, certain types of infrastructure are assigned "population equivalents" using formulae that weight the infrastructure in order to reflect the societal effects of power interruptions that would affect it. The types of infrastructure that are weighted are residential high-rise buildings, hospitals and public health facilities, public safety facilities, and other critical facilities. Figure 4-2 shows the results of Con Ed's risk and prioritization analysis from Phase 2 of its Resiliency Collaborative. The figure plots the risk reduction priority score of the 108 individual projects that were analyzed, arranged into three "risk groups" of approximately equal numbers of projects. The figure shows the aggregate capital requirements within each group. Con Ed also calculates the metric of risk reduction per $1,000 spent. This can be considered a form of cost-effectiveness index. Additional details on the Risk Assessment and Prioritization model can be found in Technical Appendix A.

Figure 4-2. Results of Con Ed Risk Assessment and Prioritization Analysis (Con Ed 2014)



The second step in Con Ed's resilience investment valuation is a CBA, for which the utility and a consultant developed avoided costs for investments based on value of reliability or lost load estimates developed by Nexant, Inc. and Berkeley Lab as part of the ICE Calculator project (Sullivan et al. 2009). Although these estimates were for power interruptions of a maximum of eight hours, Con Ed and its consultant extrapolated them to 290 hours (12 days). These extrapolations were made separately for small C&I customers, large C&I customers, and residential customers. These VOLL estimates were then applied to the results of the risk prioritization analysis described above, to monetize the benefits of the potential resilience investments and to rank these investments in terms of cost-benefit ratios and differences.[23]

Quality, accuracy, and reliability of estimation: Con Ed's overall risk, cost-effectiveness, and cost-benefit analyses are based on detailed information and reflect the utility's ongoing efforts to address resilience, as evidenced by the creation of the Storm Hardening and Resiliency Collaborative. All else being equal, the relative simplicity of the techniques used should be considered an advantage over more complex forms of modeling.

[23] At NYPSC's direction, Con Ed has developed a Benefit-Cost Analysis Handbook (Con Ed 2016). Interestingly, this handbook does not address risk assessment or quantification.

The utility appears to have exercised due diligence in adopting the ICE Calculator's VOLL estimates because these estimates were (and, in updated form, continue to be) the only such information available. However, a key issue is that the details of how the VOLL estimates are extrapolated for long-duration power interruptions are not discussed in the documentation. Also, the documentation does not discuss the details of the formulae used to calculate the "population equivalents," which, in turn, were used to quantify the impacts of power interruptions affecting critical facilities.

During regulatory proceedings, it was noted that the ICE Calculator is not based on any customer interruption costs surveys from the northeastern U.S., including the New York region. A number of stakeholders suggested that Con Ed should develop new VOLL estimates for its own customers and service territory. These were characterized by the city (and other commenters who endorsed the recommendation) as "social costs." The utility responded that undertaking a new customer interruption cost survey would be too costly. NYPSC, while recognizing the potential value of such estimates, was not convinced that the improvement in VOLL accuracy would justify the costs and did not order Con Ed to develop the new estimates.

Availability of documentation: There is extensive documentation on Con Ed risk and cost-benefit analyses, including spreadsheets with raw data and numerical calculations, publicly available in NYPSC's on-line regulatory archives. At the same time, the consultant report on applying the ICE Calculator VOLL estimates was not available, nor was information on the data and method used to estimate the model described above and the rationale and justification for the extrapolation calculations and population equivalents for critical infrastructure.[24]

Economic benefits—a*voided regional economic impacts*

Methods and techniques to estimate avoided regional impacts of power interruptions: Con Ed has not estimated the avoided regional economic impacts from investments in reliability/resilience. However, the City of New York has done so, using gross city product (GCP) – the city-scale equivalent of gross domestic product (GDP) – as the economic value metric. This analysis was part of a risk analysis of electric power outages caused by storm-induced flooding based on a storm tide and surge model and a detailed representation of the electricity network topology within the city (Tsay et al. 2014). The analysis focused solely on substation flooding. The baseline GCP growth rate was assumed to be the historical rate beginning in 1978. It was also assumed that power interruptions caused by flooding would last four days (based on the effects of Sandy), and that daily GCP would be reduced by 70% in the areas of the city experiencing interruptions, "based on the City's economic analysis."

It was reported that this analysis was conducted by McKinsey & Company, which:

[24] There is a Microsoft Excel spreadsheet accompanying the Resiliency Collaborative Phase 2 report. The spreadsheet contains the numerical extrapolated estimates, including the formulae used. However, the rationale/justification for these particular formulae are not in the publicly available documentation.

> …estimated the GDP loss for the specific area fed by a substation, using the income approach of estimating GDP, by aggregating IRS tax data by zip code and then prorating county-level GDP data. This zip-code level data was then superimposed on top of Con Edison's electrical networks to provide estimates of the GDP loss associated with different substations being out of service (Con Ed 2015a, pp. 111-112).

A comparative study of Con Ed's and the city's analyses of the potential economic impacts of future storms was conducted (in which the utility used the model and method described above) during Phase 3 of the Resiliency Collaborative (Con Ed 2015a, 2015b). The absolute differences in the two analyses' estimates of storm impact costs in both the baseline scenario – without resilience investments – and the scenario with substantial investments, were on the order of 30-40%. These differences were found to be due to Con Ed's inclusion of critical infrastructure types in its risk assessment and cost-benefit analysis. However, the two estimates of the benefits of the resilience investments as a percentage of baseline losses were quite close, as were the estimates of how investments should be allocated among the three asset risk groups (in terms of proportions). Thus, the Resiliency Collaborative endorsed the continued use of Con Ed's methodology.

Quality, accuracy, and reliability of estimates: The New York City method (described above) that was used to estimate avoided economic impacts was relatively simple. This type of straightforward analysis has advantages in terms of transparency and interpretability compared to more complex approaches. For example, this simplicity facilitated identifying the source of the differences between Con Ed's and the city's risk and cost-benefit results, an important finding that might not have been possible if the modeling tools had been more complex.

Availability of documentation: The city's indirect impact estimation was reported in regulatory documents in Con Ed rate case proceedings.

Economic benefits—o*ther avoided societal impacts*
There was little or no documentation detailing other societal impacts.

Methods and techniques to estimate other avoided societal impacts: N/A

Quality, accuracy, and reliability of estimates: N/A

Availability of documentation: N/A

Table 4-3. Availability of economic information related to mitigating future customer and regional impacts

Organization	Precipitating Event	Avoided Customer Interruption Costs	Avoided Regional Economic Impacts	Other Avoided Societal Impacts	Other	Cost-Effectiveness Analysis?	Cost-Benefit Analysis?	Comments
Consolidated Edison	Tropical Storm Sandy	●	○	○	○	**Yes**	**Yes**	Extensive documentation is available in NYPSC online regulatory archives; consultant report on applying the VOLL estimates was not publicly available
New York City (Government)	Tropical Storm Sandy	○	◒	○	○	**Yes**	**Yes**	The city's indirect impact estimation method and results were reported in regulatory documents in Con Ed rate case proceedings.

4.4 Discussion

Process and institutional aspects of preparedness and recovery planning

In contrast to Florida, Con ED and NYPSC use resilience terminology in virtually all of their efforts and initiatives related to preparing for, and recovering from, extreme weather events. However, a close examination reveals that, as a rule, the investments and measures proposed and undertaken under this rubric are more extensive, advanced, and in many cases expensive, storm-hardening actions of types already known, rather than categorically different types of actions. A related point is that the appropriate resilience "metrics" appear to have been essentially obvious from the outset. An example is enlarging the flood plain. Exactly how much it was to be expanded was a matter of debate. But it was clear that the size – expressed in area – was the metric to be used. The record indicates that the debate was not over appropriate metrics but rather about different judgments regarding the appropriate level of risk tolerance that the utility should meet and the value of reducing risk.

Also in contrast to Florida, New York's planning process has explicitly highlighted, emphasized, and incorporated climate change and its potential effects (see, e.g., NYPSC 2015). Moreover, a significant aspect of NYPSC and Con Ed resilience activities involves other stakeholders: the City of New York, academic institutions, and non-governmental organizations. We noted earlier that Florida organized a research initiative spanning utilities, universities, government, and the private sector to focus on storm hardening in the aftermath of the severe 2004-2005 hurricane season. However, the New York Resilience Collaborative appears to have been more active on a broader range of topics and to have had a much greater role in developing and improving Con Ed's practices and methods for addressing extreme weather risk than was the case in Florida. The influence of the City of New York is especially noteworthy. During the past decade, the City itself has developed and implemented an extensive program to anticipate and mitigate the risks of climate change, and the city has been an active participant in the NYPSC/Con Ed rate cases in which the company's resilience plans and expenditures have been reviewed.[25]

As is the case in Florida, New York's electric power regulation process is adversarial in the sense that all expenditures proposed by utilities are reviewed in public proceedings, carefully scrutinized – and in many cases opposed by – regulatory staff, other parts of the state government, and a number of other stakeholders. Opposition does not mean that decisions are simply impeded, but rather that multiple interests and perspectives are represented. Indeed, under the auspices of NYPSC, the Resiliency Collaborative focused disparate stakeholders on a set of difficult technical issues including how standards should be strengthened and what investments and measures should be taken to meet them, and, as noted above, the Collaborative negotiated a "consensus proposal" on these issues that was submitted to and approved by the Commission.

The activities described above may in part reflect the political and cultural context in the region where Con Ed operates, where an environmental ethos has driven a proactive response to confronting the risks of climate change, including the potential for an increasing number and severity of extreme weather events (as well as sea level rise) that can cause LDWIs. This circumstance is not unique in the

[25] We also note that, in contrast to Florida, all resilience issues have been addressed in specific rate cases.

U.S. (Deetjen et al. 2018), but the City of New York does stand out for the scale and intensity of its long-term planning initiatives related to extreme weather risk. Nevertheless, the case study indicates the importance of the policy and political context and institutional environment in addressing electricity system resilience.

How the findings relate to previous work

Con Ed, with input from others, has developed and implemented a pragmatic technical risk and cost-benefit methodology for analyzing, valuing, and selecting measures and investments in storm hardening that are larger and more expensive than has been the norm in the past. We highlight the fact that the utility and its stakeholders were able to do this largely without the need to draw upon the body of academic work on this subject beyond the information already available in the ICE Calculator. We interpret this as evidence that, to be useful in practice, efforts to improve data and methods for utilities and regulators addressing power system vulnerabilities should be undertaken with clear knowledge and understanding of how these entities are already addressing this challenge and what constitutes "improvement" from their perspectives.

Additional commentary on economic data and methods

This case study illustrates the importance of, and need for, improved empirical information both on the VOLL to utility customers – especially the costs associated with LDWIs – and on more general social costs.[26] It also reveals that the cost of developing such information can be a determinative factor for utilities and regulators. An interesting related question is whether the Con Ed storm-hardening valuation process would benefit from more complex valuation methods, including regional economic modeling. It is important to reiterate that the Con Ed/New York City comparative study found that the actual resiliency investment decisions that the utility's and the city's approaches suggested were generally equivalent. The New York City-sponsored study relied on a relatively simple economic impact analysis. For this reason, follow-on research into the value of using more complicated methods, compared to simpler ones, could be useful to regulators, the utility, and other stakeholders.

Con Ed's recently-completed NYPSC-ordered Climate Change Vulnerability Study systematically assesses potential climate change impacts on Con Ed's system and how the utility could address them (Con Ed 2019). The risks are broadly associated with changes in long-run averages resulting in higher temperatures and humidity, greater precipitation, and more frequent flooding caused by sea-level rise, as well more frequent and severe extreme weather events such as hurricanes and extended heat waves. The study describes in physical and engineering terms how these phenomena could affect different parts of Con Ed's infrastructure and operations. It proposes a "Resilience Management Framework" to "…help Con Ed build resilience over time" and to "facilitate long-term adaption" to a changing climate.

[26] The term "social costs" is used in two different ways by Con Ed, NYPSC, and other stakeholders: 1) to refer to the VOLL for electricity customers, often called "direct costs" to customers, and 2) to refer to the specific costs associated with power interruptions affecting critical infrastructure. Con Ed's benefit-cost analysis handbook (Con Ed 2016) defines "social costs" as the externality costs associated with carbon dioxide emissions. We have discussed the first two of these. It is not clear whether the third, the newly developed cost-benefit methodology, has been applied yet by Con Ed to resilience valuation.

Con Ed's study also addresses financial and economic aspects of implementing the range of investments and other actions that would build resilience. It frames this topic as follows:

> In order to minimize the financial impact of adapting to climate change, a cost-effective resilience planning process should identify a target level of resilience along with associate metrics, strike a balance between proactive and reactive spending, consider both the costs and the benefits to customers, and select adaptation strategies that provide optimal benefit at the lowest cost.

The study does not suggest a design or structure for such a process but discusses methodological issues involved in meeting the criteria it lists. While highlighting the continued lack of broadly accepted resilience metrics for energy systems, it does recognize that, even with such metrics, valuation of resilience measures (i.e., how much different resilience levels are worth), including the estimation of costs and benefits to utility customers, remains a difficult problem.

The study mentions that Con Ed's Benefit-Cost Analysis Handbook for distribution system planning allows for consideration of "social costs," such as climate change damages, and the benefits of mitigating them. At the same time, it points out that a multi-criteria approach is warranted in analyzing the risks of climate change and that this entails factors that are difficult to quantify or monetize. This makes clear that there are open questions about how to integrate improved new climate information with improved estimates of avoided customer costs and indirect economic impacts and about how this integrated risk-based economic information should be incorporated in future regulatory proceedings. Following the vulnerability study, Con Ed is preparing a climate change implementation plan, to be completed by the end of 2020.

5. Texas

5.1 Background information

5.1.1 Utility and regulatory body

The electricity market in the state of Texas encompasses unregulated power generation sources such as power plants and wind farms, unregulated retail electricity providers, and regulated transmission and distribution utilities (TDUs). The Electric Reliability Council of Texas (ERCOT) plays a crucial role as the independent system operator for the Texas electricity market. It manages the flow of electric power to 23 million Texas customers who account for 85% of the state's electricity demand. This case study focuses on two Texas TDUs: American Electric Power (AEP) Texas and CenterPoint Energy. Both companies' service territories include areas that are frequently subject to severe weather. We include two utilities in our Texas case study because each one allows us to examine a different aspect of the economic impacts of weather-related power interruptions in Texas. CenterPoint Energy serves as an example of how Texas utilities approach storm preparedness and hardening investments, and AEP Texas demonstrates how storm cost recovery takes place in the state (specifically following Hurricane Harvey).

AEP Texas, a unit of American Electric Power, is an investor-owned electric utility that owns equipment and facilities that transmit and distribute electricity in parts of the Texas Interconnection, the grid managed by ERCOT. AEP Texas' service territory encompasses virtually all of south Texas including most of the Texas Gulf coast and extends into large swaths of the central and western portions of the state. AEP Texas was formed by the merger of AEP Texas Central Company and AEP Texas North Company into one parent company on December 31, 2016.

CenterPoint Energy is a Houston-based electricity and natural gas company. It provides electric transmission and distribution services to more than 2.3 million metered customers via more than 69 retail electricity providers in a 5,000 square-mile territory that covers the vast majority of the Houston/Galveston metropolitan area. CenterPoint Energy has a consistent 2% annual customer growth rate, installing nearly 55,000 new meters each year.

PUCT regulates both AEP Texas and CenterPoint Energy. PUCT is responsible for regulating the state's electric, telecommunication, water, and sewer utilities, implementing applicable legislation, and offering customer assistance. Over the years, PUCT's mission has expanded from regulation of rates and services to include oversight of competitive markets and compliance enforcement of statutes and rules for the electric and telecommunication industries.[27] The PUCT rules are in the Texas Administrative Code (TAC), which is a compilation of all state agency rules in Texas.

5.1.2 Precipitating event

Hurricane Harvey began as an average tropical storm but intensified into a Category 4 hurricane after re-forming over the Bay of Campeche. It made landfall along the central portion of the Texas Gulf coast

[27] Adapted from PUCT website, see: https://www.puc.texas.gov/agency/about/mission.aspx

on August 25, 2017, after which it stalled with its center remaining over or near the Texas coast for four days. This led to steady and sustained rainfall that caused catastrophic flooding. Some places in southeast Texas received more than 60 inches during this period. According to a report by the National Hurricane Center (NHC), Harvey was the most significant tropical cyclone rainfall event in U.S. history, both in terms of scope and peak rainfall amounts, since reliable rainfall records began around the 1880s. Many locations in Texas received more than the previous record of 52 inches for U.S. tropical cyclone rainfall, which had been recorded at Kanalohuluhulu Ranger Station, Hawaii, in August of 1950 during Hurricane Hiki (NHC 2018b). About 300,000 customers went without power during Hurricane Harvey and its aftermath (Governor's Commission 2018). AEP restored power to more than 50% of its affected customers within five days, and more than 90% within two weeks (Walker 2017). August 28, 2017, three days after Harvey made landfall, 100,000 CenterPoint customers were without power. CenterPoint restored service to almost all of its affected customers about a week later, on September 4 (Walker, *op. cit*.).

Figure 5-1. Distribution lines in Rockport, Texas following Hurricane Harvey (Reuters 2017)

5.1.3 Regulatory and policy responses

The PUCT has substantive rules for all of its regulated electric service providers (Chapter 25). Following Hurricanes Rita and Ike in the mid-2000s, the Commission and the state legislature initiated an extensive process of reviewing and improving the requirements for utility storm hardening and related activities and adopted new rules and regulations (Carey 2014). The rules provide comprehensive criteria for utilities to plan for and respond to hurricanes and other storms, both proactive (storm hardening) and reactive (storm recovery). Section 25.95, which took effect on July 13, 2010, requires each electric utility to develop a storm-hardening plan for implementation of *cost-effective* strategies to increase the ability of its transmission and distribution facilities to withstand extreme weather conditions (TAC 2010). This section stipulates that, by May 1, 2011, each utility should have filed a summary of its storm-hardening plan, incorporating details about the utility's current and future storm-hardening actions. In addition, each utility is required to provide a detailed annual summary of its implementation and any revisions of the plan. Regarding recovery, Section 25.53, which took effect on June 26, 2014, requires each electric utility to file a copy of its Emergency Operations Plan (TAC 2014). There are also other sections pertaining to system reliability.

In response to Hurricane Harvey, the PUCT initiated a case titled "Issues Related to the Disaster Resulting from Hurricane Harvey" (Case No. 47552) on August 28, 2017. In addition to guiding electric utilities and Commission staff on reviewing utilities' responses to Hurricane Harvey, the PUCT also directed its staff to collaborate with utilities to improve preparedness for future major weather events, based on lessons learned from Hurricane Harvey. The Texas Department of Public Safety Division of Emergency Management, PUCT staff, and utilities formed a working group, which, in turn, formed four task forces that completed most of their work by July 2018 (PUCT 2018).) The responsibilities of each task force were as follows:

- Task Force 1: Utility and Commission Staff Collaboration with the State Operations Center
- Task Force 2: Utility-Specific Actions (Infrastructure-related preparedness actions)
- Task Force 3: Utility Collaboration through Mutual Assistance
- Task Force 4: Collaboration between Electric Utilities and Commission Staff

Table 5-1. Time frame of storms, regulatory responses, and utility activities

Time frame	***Event and activity***
2005	• Hurricane Rita makes landfall as a Category 3 hurricane at the Texas/Louisiana border.
2008	• Hurricane Ike makes landfall as a Category 2 hurricane at Galveston TX.
2010-2011	• PUCT issues Electric Utility Infrastructure Storm-Hardening regulation to ensure that each utility develops a Storm-Hardening Plan to prepare for extreme weather conditions by enhancing its transmission and distribution facilities.
2015	• On April 30, AEP Texas files a summary of its Emergency Response Plan with PUCT.
2017	• On August 25, Hurricane Harvey makes landfall as a Category 4 hurricane along the central portion of the Texas Gulf coast, near Corpus Christi. • On August 28, PUCT initiates Case Number 47552 "Issues Related to the Disaster Resulting from Hurricane Harvey."
2018	• On August 7, AEP Texas files an application for a determination by PUCT on its system restoration costs incurred as a result of Hurricane Harvey and other previous weather-related events.

Time frame	*Event and activity*
2019	• On February 28, PUCT grants its determination of the system restoration costs settlement agreement proposed by AEP Texas. • On March 8, AEP Texas submits an application to PUCT seeking approval to securitize $229 million in distribution-related costs associated with restoration of service.

5.2 Event response and immediate recovery

Engineering and operational elements

During service restoration, AEP Texas reported that 549 transmission line structures, 8,260 distribution poles, 333 miles of transmission conductors, and 850 miles of distribution conductors were either damaged or destroyed. The impact categories recorded in the testimonies also include distribution lines, circuits, and underground distribution facilities (AEP Texas 2018a,b,c; PUCT 2019a,b).

Cost recovery

As discussed earlier, AEP Texas is an investor-owned utility regulated by the PUCT. Chapter 36, Subchapter I of the Public Utility Regulatory Act authorizes an ERCOT electric utility to quantify and recover system restoration costs after a hurricane or other weather-related event. It also authorizes the utility to use securitization[28] financing to recover the distribution-related costs and the ERCOT transmission cost-recovery mechanism to recover the transmission-related costs. After Hurricane Harvey, AEP Texas filed a petition for a determination by the PUCT of its system restoration costs incurred in association with Harvey and other previous weather-related events. The initial application was filed on August 7, 2018, and the settlement was approved on February 28, 2019. This was followed by a second step of filing for securitizing distribution-related costs, accounting for carrying costs, insurance proceeds, and tax offsets. AEP Texas initiated this process on March 7, 2019; it is ongoing.[29]

According to AEP, storm O&M recovery mechanisms differ by jurisdiction. Because of the history of AEP Texas, AEP North and AEP Central follow separate storm O&M recovery mechanisms. For Texas North, storm costs are normally expensed as incurred and are included in base rates during its test year; for Texas Central, an approved catastrophe reserve of $1.3 million annually in base rates allows deferral of all storm costs above $500,000 with recovery through base rates or potential securitization (AEP 2018c).

[28] Securitization is a financial mechanism in which the utility packages and sells its debt to investors in the form of bonds that pay the investors from future customer charges. The proceeds from the sales of these securities are available to the utility immediately and can be used to pay down existing, higher-cost debt. Securitization effectively reduces the cost of financing because future utility revenues are relatively certain and backed by ratepayers.

[29] The second filing is associated with restoration of service, which seeks securitization financing for $229 million in distribution-related costs. According to AEP Texas, customers can benefit from the securitization, upon approval. The estimated amount charged to the retail electricity providers for a residential customer using 1,000 kWh per month would be approximately $1.33 per month over a 10-to-15-year period (AEP 2019a). The actual amount charged and number of years may differ, depending on the terms of system restoration bonds. The details included in the testimony indicate that the securitization includes an application for "a separate tariff designed to credit to customers ADFIT [accumulated deferred federal income tax] benefits associated with the incurrence and recovery of system restoration costs."

Categories of expenses: In AEP Texas' petition for determining system restoration costs, the utility estimated costs separately at the transmission and distribution levels. At each level, costs were broken down into the following categories: (1) non-Hurricane Harvey system restoration costs; (2) Hurricane Harvey actual system restoration costs through April 30, 2018; (3) estimated Hurricane Harvey system restoration costs; (4) estimated incremental litigation costs for the filing (Docket No. 48577); (5) estimated employee-retention tax credit; and (6) insurance proceeds.

Distribution-related system restoration costs attributable to Hurricane Harvey were disaggregated into the following major resource categories: affiliated billings, labor, materials and supplies, outside services, allowance-for-funds-used-during-construction/overheads, transportation/fleet, travel, and employee expenses.

AEP Texas identifies the following types of outside services costs, which are not exhaustive:

- Mutual assistance utilities
- Line contractors
- Distribution-related substation contractors
- Vegetation contractors
- Line recovery and disposal contractors
- Engineering contractors
- Environmental contractors
- Transportation contractors
- Telecommunications contractors
- Logistics contractors

According to a PUCT report (2019a), Hurricane Harvey caused a total of $700 million in estimated damage to electricity system infrastructure.

Accounting procedures: AEP Texas reported all of its accounting transactions for system restoration costs, along with its filing for petition, based on regulatory accounting principles. A storm work order review was included in the testimony. The work order review contains guidelines on storm restoration costs expressed as percentage shares that depend on the type of storm. In the case of a hurricane, O&M accounts for 60%, capital accounts for 35%, and removal accounts for 5% of the total cost (PUCT 2019c). In practice, however, the actual percentage shares may differ to reflect actual restoration work activities.

Methods and techniques to estimate costs to utilities: The billing method used in the cost-recovery request was a work-order-based accounting system, which identifies and bills each service performed for affiliate companies, including storm restoration services. The evaluation and defense of these costs was based on precedents set in prior rate cases and other proceedings.

Quality, accuracy, and reliability of estimates: AEP Texas provided extensive detail on both transmission and distribution costs. There are records of specific dates, length, labor, and affiliates involved in every restoration activity. The detailed records appear to be reliable sources for determining cost recovery. It was noted that additional labor was brought in to assist in the aftermath of Hurricane Harvey. However, all of these costs were listed in a general labor category, so it was difficult to determine the additional costs attributable to increased labor and customer service.

AEP Texas's securitization filing also includes detailed system restoration charge factors. The system restoration cost varies by customer class (residential, primary service, secondary service, lighting service). Information detailing 12 months of system restoration cost billing units and non-standard true-up threshold units was also provided. The detailed analysis of how the securitization impacts customers can be found in the documents of its securitization application on the PUCT website (Docket No. 49308).

Availability of documentation: All information on the impacts of Hurricane Harvey is based primarily on AEP Texas' PUCT filings for system restoration costs. As discussed earlier, there are detailed tables, in the form of spreadsheets, accessible by searching the filings on the PUCT website. No additional reports had been found through AEP or AEP Texas's website through September 2019 (Docket Nos. 48577, 49308).

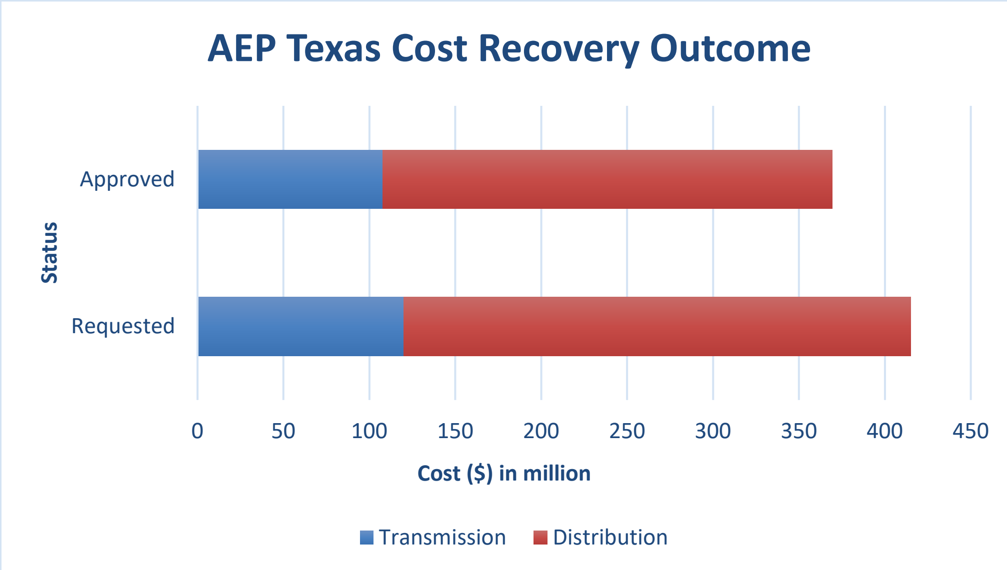
Table 5-2. Availability of economic information related to cost recovery

Utility	Precipitating Event	Trans. System Costs	Dist. System Costs	Gen. System Costs	Increased Customer Service Costs	Other Costs	Comments
AEP Texas	Hurricanes of 2005, 2008, and 2017	●	●	N/A	◒	●	"Other" category includes expenses for required activities in support of restoration work, such as charge for land rights and settlement of damage claims incurred from transmission construction activities.

Cost recovery request and outcome

On February 28th, 2019, the PUCT issued the order for case 48577, which was AEP Texas' application for determination of system restoration costs. The settlement agreement included a $5 million reduction to AEP Texas's requested distribution-related Hurricane Harvey system restoration costs, a reduction of $3,745,114 to AEP Texas's requested transmission-related system restoration costs since this amount was incorrectly included as storm-related costs, and a reduction of $571,200 to AEP Texas's requested system restoration costs relating to the estimated litigation expenses with this docket (PUCT 2019c). The approved system restoration costs for both transmission and distribution were categorized as: non-hurricane Harvey system restoration costs, Hurricane Harvey system restoration costs, insurance proceeds, and employee-retention tax credit. Figure 5-2 shows the amount requested by AEP Texas and the final value approved by the PUCT, for both transmission and distribution systems.

Figure 5-2. AEP Texas cost-recovery request and approval



5.3 Preparing for the future

Upgrading infrastructure, maintenance, and readiness standards

In addition to the replacement of transmission and distribution infrastructure discussed earlier, AEP Texas upgraded some infrastructure during its post-hurricane restoration process. The utility replaced damaged wooden line supports with single-pole steel structures, which are able to better withstand hurricane-force winds.[30]

Regarding activities to prepare for future storms, AEP and other Texas utilities are subject to the Texas Administrative Code Section 25.95 regarding electric utility infrastructure storm hardening, which is defined as "all activities related to improved resiliency and restoration times, including but not limited to emergency planning, construction standards, vegetation management, or other actions before, during, or after extreme weather events" (TAC 2010). Section 25.95 requires that a utility's storm-hardening plan be updated at least every five years and include the following elements:

1. Construction standards, policies, procedures, and practices employed to enhance the reliability of utility systems
2. Vegetation management plan for distribution facilities
3. Plans and procedures to consider infrastructure improvements for distribution system based on smart grid concepts
4. Plans and procedures to enhance post-storm damage assessment
5. Transmission and distribution pole construction standards, pole attachment policies, and pole testing schedule
6. Distribution feeder inspection schedule

[30] Adapted from AEP Texas news release, see: https://www.aeptexas.com/info/news/viewRelease.aspx?releaseID=2471

7. Plans and procedures to enhance the reliability of overhead and underground transmission and distribution facilities through the use of transmission and distribution automation
8. Plans and procedures to comply with the most recent NESC wind-loading standards in hurricane-prone areas for new construction and rebuilds of the transmission and distribution system
9. Plans and procedures to review new construction and rebuilds to the distribution system to determine whether they should be built to NESC Grade B (or equivalent) standards
10. Plans and procedures to develop a damage/outage prediction model for the transmission and distribution system
11. Plans and procedures for use of structures owned by other entities in the provision of distribution service, such as poles owned by telecommunications utilities
12. Plans and procedures for restoration of service to priority loads and for consideration of targeted storm hardening of infrastructure used to serve priority loads

Section 25.53 on electric service emergency operations plans addresses the reliability of infrastructure (TAC 2014). It explicitly requires that a market entity should test its emergency procedures by conducting or participating in at least one drill annually unless these procedures have been implemented in response to an actual event within the previous 12 months. On April 30, 2015, AEP Texas filed a comprehensive summary of its Electric Service Emergency Operations Plan in compliance with this rule.

As required by Rule 25.95 mentioned above, CenterPoint Energy proposed and submitted its first Storm-Hardening Plan in April 2011 and has provided an annual summary of its implementation of the plan ever since. The initial plan provided a comprehensive response to the PUCT's new storm-hardening requirements, addressing each requirement included in Section 25.95. The annual updates of CenterPoint's storm-hardening plans thoroughly document the progress and implementation of these plans. Starting in 2014, CenterPoint Energy's annual reports have featured a list of additional storm-hardening projects including their operational areas, description, estimated completion time, and estimated cost. The Freeport Area plan, for example, details transmission projects completed in the Freeport area since 2012 that are intended to enhance the system's reliability during storms (CenterPoint 2017a). There do not appear to be any discernible differences in CenterPoint's storm-hardening plans before and after Hurricane Harvey. The Storm-Hardening Plans and Emergency Operations Plan from CenterPoint Energy and AEP Texas are detailed in a significant number of regulatory filings (CenterPoint Energy 2011, 2012, 2014, 2015, 2016, 2017b, 2019; AEP Texas 2015a).

Economic benefits—*avoided customer interruption costs*

The aforementioned TAC 25.95 rule requires that utilities' proposed storm-hardening plans include "cost-effective" strategies. In response, in its initial storm-hardening plan in 2011 (CenterPoint 2011), CenterPoint Energy provides its substation planning criteria for a cost-effective, reliable design to accommodate changes in the electrical system load variances under several circumstances. In addition, it provides specific annual estimates for proactive tree trimming and hazard tree removal because falling trees and branches are the primary cause of damage and outages during an extreme storm. The hardening plan also estimates costs for the Central Houston Area Automation Project, which implements an Intelligent Grid network covering the Texas Medical Center and multiple key central business districts in Houston. Costs of CenterPoint Energy's vegetation programs and infrastructure inspections are also included. Starting in 2014, CenterPoint Energy began listing the estimated costs and completion times for all its storm-hardening plans (CenterPoint 2014).

As a result of storm preparation activities, power interruptions resulting from extreme weather events are expected to be less severe, thus reducing the costs to customers of lost load. In principle, these expected benefits should be sufficiently large to justify the costs of the hardening activities themselves, which must be paid for using the utility's rate revenues. In its annual summaries of its storm-hardening plans, CenterPoint did not include detailed cost-benefit analysis or specify the methods it adopted to determine the cost-effectiveness of these programs. The utility did conduct a cost-benefit analysis of its Intelligent Grid Project, which was included in its application for rate changes in 2019 (Case No. 49421). The study was conducted in 2014 as a collaboration between the Electric Power Research Institute (EPRI) (2014) and CenterPoint (2014). The analysis used a business-as-usual automation base case and a pre-planned intelligent grid design to evaluate the costs and benefits of deploying a system-wide intelligent grid across CenterPoint's electric distribution system. The ICE calculator was used to estimate the value of reliability improvement. In both scenarios, customers benefit from reduced interruptions, and these benefits consistently outweigh the investment costs. The study claimed that "the benefits of the Intelligent Grid Design are more than six times greater than simply following historical deployment patterns."

Although we could not find any concrete evidence of AEP Texas or CenterPoint Energy using avoided costs or VOLL estimates to quantify the benefits of storm hardening, VOLL estimates exist for the ERCOT system (e.g., London Economics 2013), and there is an example of VOLL being used in CBAs of undergrounding transmission and distribution lines across Texas (e.g., Larsen 2016). Larsen (2016) conducted an ex-ante CBA of a hypothetical mandate by the PUCT to underground all overhead transmission and distribution lines when they reach the end of their useful life. This study found that this undergrounding mandate would lead to large net social losses (costs exceeding the benefits) but that targeted undergrounding initiatives could result in net social benefits.

A report prepared by London Economics for ERCOT stated that "average VOLLs for a developed industrial economy range from approximately $9,000/[megawatt-hour] MWh to $45,000/MWh." In general, residential customers have a lower VOLL ($0 – $17,976/MWh) than commercial and industrial customers ($3,000 – $53,907/MWh) (London Economics 2013). ERCOT uses the $9,000/MWh VOLL estimate as the system-wide offer cap in its energy-only electricity market, which sets the maximum market price during scarcity pricing periods (ERCOT 2016). However, despite having VOLL estimates available, neither AEP Texas nor CenterPoint Energy appears to use these values in cost-benefit analyses submitted to the PUCT.

Quality, accuracy, and reliability of estimates: As explained above, there is a VOLL estimate for the ERCOT grid, but whether or how it is incorporated into a comprehensive evaluation of storm-hardening investments is unclear either because there is no formal cost-benefit analysis or documentation describing it. CenterPoint's CBA of the Intelligent Grid Project is comprehensive and transparent. The study considers two alternative investment schedules (intelligent grid design and automation base case) and follows two analytical tracks (one estimates the customer value of reducing interruption time, and the other records capital expenditures and intelligent grid expenses, including conversion of capital expenditures into revenue requirements). Detailed reliability metric calculations (e.g., SAIDI) and cost-benefit comparisons are presented in tables and charts.

Availability of documentation: As described above, CenterPoint Energy provides substantial documentation of its storm-hardening activities, including cost estimates and completion times. However, aside from the Intelligent Grid Project, there is little or no documentation of the estimated benefits of these actions, nor are there comparisons of benefits and costs. There is also little or no information about the decision-making process that led to certain programs being selected for implementation.

Economic benefits—a*voided regional economic impacts*

We could not identify any direct or indirect economy-wide impacts of power interruptions reported by the utility or the public utility commission related to Hurricane Harvey.[31]

Methods and techniques to estimate regional economy-wide impacts: N/A

Quality, accuracy, and reliability of estimates: N/A

Availability of documentation: N/A

Economic benefits—o*ther avoided societal impacts*

We found no evidence that the utility or regulator considered other societal impacts in their assessment of strategies and programs to mitigate the impacts of future power interruptions.

Methods and techniques to estimate other avoided societal impacts: N/A

Quality, accuracy, and reliability of estimates: N/A

Availability of documentation: N/A

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[31] Several studies have been conducted on the total estimated costs of Hurricane Harvey. According to the National Oceanic and Atmospheric Administration (NOAA), the estimated total cost of Hurricane Harvey is $125 billion (NOAA 2017). An article by the Council of Economic Advisers pointed out that Hurricane Harvey led to an equivalent of about 2 million people in Texas and Louisiana missing one week of work, and it lowered the growth rate of real GDP in that quarter (the third quarter of 2017) by 0.2 percentage points (CEA 2017). This is based on a rule of thumb that dislocating a million workers will lower the growth rate of real GDP in that quarter by 0.1 percentage point.
As for the indirect economic impacts of Hurricane Harvey, a review from the Texas Comptroller of Public Accounts defines indirect damage from Hurricane Harvey as "the interruption of business activity caused by the storm – disruptions caused by safety concerns, the loss of electrical power, damaged machinery or the temporary inability of employees to reach work." From this review, the estimated indirect impacts (losses net of gains) to the gross state product during the first year following the storm are $3.8 billion in losses (TCPA 2018).
Although the Hurricane Harvey economic impact estimates described above acknowledge that they include electrical power outages within their scopes, they do not specifically attribute a portion of their overall estimates to power interruptions. For this reason, they are not formally included in this analysis of available economics information.

Table 5-3. Availability of economic information related to mitigating future customer and regional impacts

Organization	Precipitating Event	Avoided Customer Interruption Costs	Avoided Regional Economic Impacts	Other Avoided Societal Impacts	Other	Cost-Effectiveness Analysis?	Cost-Benefit Analysis?	Comments
CenterPoint Energy	Hurricanes of 2005, 2008, and 2017	◒	○	○	○	**Yes**	**Yes**	Utility—in partnership with EPRI—conducted a cost-benefit analysis of the *Intelligent Grid Project*.

5.4 Discussion

Process and institutional aspects of preparedness and response planning

Stakeholders other than the utility and the public utility commission are involved in the types of regulatory proceedings we have discussed. Stakeholders include, but are not limited to: City of McAllen, Gulf Coast Coalition of Cities, and the Steering Committee of Cities Served by Oncor (collectively, Cities). The outcomes of such proceedings affect the cost of transmission service rates, which are paid by ratepayers located within ERCOT. In addition, the Cities are required to participate in the proceedings as noted in Public Utility Regulatory Act Section 33.025.

How the findings relate to previous work

Regulatory and utility documents in both the AEP Texas and CenterPoint Energy cases specifically refer to "resilience," but the term is not addressed as extensively as in the Con Ed case, for example. AEP Texas and CenterPoint Energy do not formally define "resilience." The PUCT and ERCOT use FERC's definition.[32] As part of its cost recovery efforts, AEP Texas initiated a two-step regulatory process with the PUCT. The first step, which was completed in early 2019, was a determination of the necessity of costs related to both transmission and distribution. The second step, which is ongoing, seeks approval for securitizing distribution-related costs.

CenterPoint Energy filed multiple storm-hardening plans beyond the framework required by the PUCT for enhancing the system's ability to respond to future extreme events under NESC rules.[33] It appears that CenterPoint's storm-hardening plans follow the standards laid out by Section 25.95 and conform to NESC requirements. As in Florida, storm cost recovery and storm hardening are treated in separate regulatory processes.

Additional commentary on economic data and methods

As discussed earlier, we could not find any documentation from CenterPoint Energy estimating the avoided customer costs from investments to mitigate future impacts of power disruptions. CenterPoint Energy has not published estimates of the direct or indirect impacts of power interruptions on customers in its territory or indicated what methods it would employ to come up with such an estimate. One exception is the Intelligent Grid Design project, in which a formal cost-benefit analysis was conducted using VOLL estimates. It also remains unclear whether VOLL estimates cited by ERCOT are being incorporated into CBAs of storm-hardening projects because we could not find any additional CBAs by the utilities. Estimates of regional economic impacts resulting from power interruptions, including effects on GDP and/or employment, appear to be unavailable. In addition, there are no examples of the utilities considering other avoided societal impacts from storm hardening in the wake of Hurricane Harvey.

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[32] FERC defines resilience as "the ability to withstand or recover from some disturbance" (FERC 2018). However, the sole mention of "resiliency" in the aforementioned Texas law on rules for electric service providers is specifically in reference to storm hardening.

[33] Note, however, that the NESC itself does not mention the term "resilience" throughout a document totaling approximately 400 pages (IEEE 2017).

However, after Hurricane Ike, the PUCT issued a Request for Proposals to carry out a CBA of potential interventions for improving electricity and telecommunications infrastructure to minimize long-term outages and restoration costs associated with Gulf Coast hurricanes. Quanta Technology – using hurricane damage and cost data provided by utilities as well as a hurricane simulation model – evaluated the costs, utility benefits, and societal benefits of a variety of storm-hardening activities (Brown 2009). Forensic analysis of the data correlated extreme weather data to infrastructure failures in specific locations across the Gulf Coast. The model was designed to simulate hurricane years to project the occurrence of hurricanes and their major features such as landfall location, path, and infrastructure damage. This study recommended improved post-storm data collection, hazard tree removal, and targeted hardening of electricity distribution infrastructure as cost-effective actions by utilities. In addition, the Quanta Technology report suggested that a resilience-based framework could be developed to evaluate storm-hardening programs. Such a framework would allow comparison of the costs and benefits of storm hardening and storm recovery; there was no explicit comparison available at the time of this study. This recommendation the 2009 PUCT-sponsored report remains relevant 10 years later.

6. California

6.1 Background information

6.1.1 Utility and regulatory body

The state of California is served by several large investor-owned electric utilities (IOUs) and numerous publicly owned and other load-serving entities. This case study focuses on the San Diego Gas & Electric Company (SDG&E, an IOU that was incorporated in 1905 and today serves more than 3.5 million customers in San Diego and southern Orange counties, a service territory of more than 4,000 square miles.

SDG&E is regulated by the California Public Utilities Commission (CPUC, which determines rates for electricity and natural gas provided by private utilities in California, as well as rules and regulations pertaining to reliability, environmental aspects of energy production, distribution, and consumption, along with other matters.[34] In addition, the state legislature and other government agencies, including the California Energy Commission, have long played a very active role in energy and environmental policy and technical issues, including those involving electric utilities.

6.1.2 Precipitating event

Throughout the twentieth century, California experienced destructive fires at "wildland-urban interfaces," areas where residential housing is built in or near wildland vegetation (Radeloff et al. 2018). The state's vulnerability to such fires continues to increase because of factors including continued human development in fire zones, forest management practices (particularly in Northern California), and a changing climate.[35] As noted in Section 2, 15 of the 20 most destructive California wildfires of the past century have occurred since 2000 (CAL FIRE 2019a,b).

A number of destructive wildfires occurred in Southern California in October 2007. These were driven by an unusually severe occurrence of Santa Ana winds, which are hot, dry, gusty winds originating in the Great Basin to the east (Kalansky et al. 2018). These fires burned more than 500,000 acres, destroyed more than 3,000 homes and other buildings, and resulted in 17 deaths (CAL FIRE 2009). Several of these fires were in the SDG&E service territory, including the so-called Witch Fire, which burned nearly 200,000 acres, destroyed more than 1,500 structures, and caused two deaths (CAL FIRE 2019b). The Witch Fire currently stands as the sixth most destructive California fire in terms of property loss since modern record keeping began in 1932. Several of the most severe October 2007 fires, including the Witch, were subsequently determined to have been caused by electric power lines. Moreover, for the

[34] The CPUC also regulates water, transportation, and telecommunication companies in the state.

[35] Radeloff et al. (2018) discuss the growing wildfire risks from expanding wildland-urban interfaces throughout the U.S.

first time in the state's history, the costs of these fires exceeded the utility's insurance liability coverage. The incidence of catastrophic wildfires in California has increased even further since that time.[36]

Figure 6-1. Example of a fire in the San Diego County wildland-urban interface (San Diego Union-Tribune 2013)

6.1.3 Regulatory and policy responses

This case study differs from the others in this report in that the human, physical, and economic impacts of the precipitating events were not from the resulting power outages but instead from damage caused by the utility's infrastructure. As we describe below, the 2007 fires resulted in significant regulatory activity and changes to the ways in which SDG&E and other California utilities manage wildfire risks, a process broadly parallel to the storm-hardening and resilience processes in the other states studied in this report. However, the economic issues are somewhat different. We return to this point in Section 6.4.

[36] Subsequently, 2017 and 2018 were the worst fire seasons in the 85 years of recorded wildfire history in the state; the two most destructive fires of this period in terms of area burned, property destroyed, and lives lost both occurred in 2018. The Mendocino Complex fires in July 2018 burned more than 450,000 acres in four Northern California counties; the Camp Fire in November in Butte County, in north-central California, destroyed almost 20,000 structures and resulted in 85 deaths (CAL FIRE 2019a,b).

The State of California began regulating construction and maintenance of overhead power lines in the early twentieth century. General Order (GO) 95, originally issued by the CPUC in 1941, specifies detailed engineering rules for these purposes, as well as for reporting of safety hazards and accident investigations (CPUC 1941). It was supplemented in 1997 by GO 165, which updated several definitions, equipment inspection cycles, and reporting rules. These were the regulations governing SDG&E's and other California utilities' fire safety practices at the time of the October 2007 Southern California fires.

In the aftermath of these fires, the CPUC began an aggressive effort to improve fire safety on the part of the state's regulated electric utilities by reducing the fire-related risks associated with overhead power lines and communications facilities adjacent to them (CPUC 2008). In August 2009, it ordered electric utilities to immediately implement fire-prevention measures prior to the fall fire season (CPUC 2009).

Over the following two years, the Commission oversaw an extensive technical review and analysis of the utilities' fire hazards and risks, organizing a series of workshops that included the IOUs, Commission staff, consumer groups, independent consultants, and several other stakeholder representatives. Drawing on proposals developed in these workshops, the CPUC issued detailed new regulations in January 2012 (CPUC 2012). These included requiring faster correction of identified hazards, more frequent inspections of facilities in high-fire-threat areas, improved vegetation clearing, development of plans to prevent power-line fires during extreme fire weather events, and development of fire-threat maps. Utilities were instructed to submit updated fire prevention plans by December 31 of that year.

The CPUC began a new proceeding in May 2015 to further develop and enhance fire-safety methods and practices, specifically for areas of the state where there is elevated risk of power-line-caused wildfires (CPUC 2015). Further studies and analyses were conducted over the following two years, including the creation of more advanced and detailed fire safety maps. The Commission issued updated rules and amendments to the relevant state GOs in December 2017 (CPUC 2017b). These included the designation of certain areas in the state as "High Fire-Threat Districts (HFTDs)" and more stringent safety requirements for these locations, such as more frequent inspections and stricter vegetation management. In addition, utilities were instructed to prepare fire safety management and preparation plans specifically for HFTDs.

Following the extremely destructive fires in Northern California in July 2018 (cf. footnote 32), the California State Senate passed legislation regarding wildfires, which was signed into law by Governor Brown the following month. The new law, Senate Bill (SB) 901, contained a number of provisions pertaining to electric utilities that expanded the requirements for their wildfire prevention and mitigation planning, and rules on criteria for cost recovery following fires. In October 2018, the CPUC began a new proceeding to implement these and related parts of the law (CPUC 2018c). SDG&E filed its updated wildfire prevention plan with the Commission in February 2019 (SDG&E 2019a,b). In April 2019, the administrative law judges (ALJs)in the case decided that the plans of eight utilities, including SDG&E, contained the elements required by SB 901 but also needed certain improvements. The full

Commission concurred with this decision in June, instructing SDG&E and the others to make the identified improvements in their next wildfire mitigation plans.

In recent years, several other policies and regulatory activities in California have addressed wildfire mitigation. First, in 2013, the CPUC initiated a rulemaking to develop a risk-based decision-making framework to evaluate safety and reliability improvements in the context of general rate cases (CPUC 2013, 2014). This rulemaking addressed a number of issues involving risk and uncertainty, including cyber-security, grid vulnerability to wildfires or levee breaks, and recoverability from power outages. As in the case of SDG&E, the methods and tools developed in the course of this rulemaking now play an important role in wildfire mitigation planning.

Second, the State of California has long supported research and planning activities related to anticipating and mitigating the possible impacts of climate change on the state's natural and human systems (see, e.g., Sathaye et al. 2011). In April 2018, the CPUC initiated a rulemaking to comprehensively review issues associated with how electric utilities address climate adaptation (CPUC 2018a,b). This activity also bears on SDG&E's wildfire planning, as we discuss below.

Table 6-1. Timeline of fires, regulatory responses, and utility activities

Timeframe	***Event or activity***
2007	● Catastrophic Southern California wildfires, including Witch and others, impact SDG&E's service territory, October.
2008	● CPUC initiates rulemaking on fire safety, November.
2009	● SDG&E petitions CPUC to recover costs associated with the 2007 fires, August. ● CPUC orders utilities to take preventive safety measures before the start of the 2009 fire season, August.
2012	● CPUC adopts new fire safety regulations, January.
2013	● CPUC institutes rulemaking to develop a risk-based decision-making framework for safety and reliability improvements, November.
2014	● CPUC adopts additional new fire safety regulations, February. ● SDG&E submits updated fire prevention plan, October.
2015	● CPUC begins proceeding to develop and adopt fire-threat maps, May.
2017	● SDG&E submits updated fire prevention plan, October. ● Catastrophic wildfires take place in October (Northern California) and December (Southern California, Ventura and Santa Barbara Counties). ● CPUC denies SDG&E application to recover costs of 2007 fires, November. ● CPUC adopts High Fire-Threat District regulations (including maps), December.
2018	● Catastrophic Mendocino Complex fire takes place in Northern California, July.

	● California State Senate passes, and Governor Brown signs, Senate Bill (SB) 901 on wildfire mitigation and related topics, August-September. ● SDG&E submits updated fire prevention plan, CPUC opens rulemaking on implementing SB 901, October. ● Catastrophic Camp Fire takes place in Butte County, November ● CPUC approves SDG&E progress on implementing risk management (Risk Assessment Mitigation Phase [RAMP] and Safety Model Assessment Proceedings [S-MAP]) methods, December.
2019	● CPUC initiates rulemaking on wildfire cost recovery pursuant to SB 901, January. ● SDG&E submits SB 901-compliant wildfire mitigation plan to CPUC, February. ● Administrative Law Judge (ALJ) finds SDG&E and other utilities' wildfire mitigation plans consistent with SB 901, forwards to full commission for decision, April. ● CPUC accepts ALJ decision and instructs utilities to make specific improvements in 2020 wildfire mitigation plans.
2020	● CPUC issues resolutions on updated procedures and guidelines for wildfire mitigation plans and their review, January and June. ● SDG&E and other California utilities submit first wildfire mitigation plans under updated procedures and guidelines, February-March; these are accepted with conditions by CPUC, June.

6.2 Event response and immediate recovery

Engineering and operational elements

Electric utilities in California are required to submit "fire incident reports" that include basic data on fires involving their facilities or infrastructure. The data include location, size (in acres), facilities involved, and any resulting power outages. The complete list of the information submitted in these reports is presented in the Technical Appendix. The reports do not include the causes of fires, which in the case of serious wildfires are subject to extensive investigations by the California Department of Forestry and Fire Protection (CAL FIRE), local fire authorities, the CPUC's Safety and Enforcement Division, and other state and federal agencies. An example is the previously cited joint report on the 2007 Southern California wildfires by CAL FIRE, the U.S. Forest Service, and the California Governor's Office of Emergency Services (CAL FIRE 2009).

Cost recovery request and outcome

SDG&E filed an application for recovery of its costs associated with the 2007 fire in 2009 (SDG&E 2009). The CPUC's review of the application, and its ultimate decision, were a complex process that took nearly a decade to complete. In California, "cost-of-service utilities are entitled to recover the reasonable costs they incur to comply with the regulations…after the reasonableness of such costs has been verified by the Commission" (CPUC 2017b). In this instance, "reasonableness" was primarily a matter of whether the utility had prudently maintained and operated its network; taken steps to prepare for the fires and protect its infrastructure from them; and responded appropriately once they started to spread.

After intensive investigation by state and federal government agencies, local authorities, SDG&E, and CPUC, the precipitating cause of the Witch fire was determined to a fault in a single between-pole segment of one of SDG&E's overhead transmission lines that resulting in arcing. This resulted in hot particles falling to the ground, which ignited the fire, which was then spread rapidly by high winds. The utility maintained that it had in fact prudently maintained and operated the line, and prepared for and responded to the fire, but that the series of events that caused it were not in its control. CPUC staff and many other stakeholders strongly disagreed. The determination of this issue encompassed the submission and analysis of a voluminous body of technical evidence and legal arguments by the utility and others.

Categories of expenses: The incurred costs of the 2007 wildfires for recovery of which SDG&E applied to the CPUC were primarily legal costs associated with lawsuits filed against the utility for damages caused by the fires, in the form of settlement payments and SDG&E's direct costs of litigation. They also sought to recover the direct repair and recovery costs incurred immediately following the 2007 fires. The "gross" amount of all these costs was $2.4 billion. After deducting insurance settlements and several other offsets, SDG&E requested that $379 million be recovered through its rates (CPUC 2017b).

Accounting procedures: The accounting procedures for this application were themselves a matter of dispute. Following standard state regulatory practice, cost accounting for the fires was based on the use of a "Wildfire Expense Memorandum Accounts," a mechanism for recording costs pending Commission decisions on recovery through rates.[37] However, SDG&E also requested CPUC approval of a different "balancing account" to record certain costs including post-fire recovery and repair, the justification for which was the subject of dispute in the proceedings. The Commission denied the request in 2012.

Methods and techniques to estimate costs to utilities: Given the types of costs in this case, there were no technical methods that were required to estimate them.

Quality, accuracy, and reliability of estimates: It is not possible to make an independent assessment of these aspects of the costs that SDG&E reported to the CPUC. The costs were intensively scrutinized during the Commission review proceeding, which is adversarial in nature, and many, if not most, of the details were reported during the proceeding discovery phase and debated by the CPUC Office of Ratepayer Advocates and other stakeholders. The amount of information involved in the review of the claims was extremely large, and the process took several years. We note that this process focused primarily on the justifications for and appropriateness of cost recovery. If this were considered a matter of assessing "quality, accuracy, and reliability," the final judgment of these attributes is the responsibility of the Commission itself, which, as noted above, ultimately denied SDG&E's recovery request.

[37] Regulated California energy utilities use memorandum accounts for many different types of costs.

Availability of documentation: There is an extremely large amount of documentation available on line from the CPUC, as well as from SDG&E itself, although we were unable to find information on the direct recovery and restoration costs incurred by SDG&E following the 2007 fires. Moreover, we did not locate information on the details of the legal settlements that the utility reached with the claimants. Given the adversarial nature of the proceeding, the information a utility must submit to the regulators or other parties in this or any similar process is, to a degree, a matter of dispute and determined during the course of the proceeding itself. For example, some information is acknowledged to be subject to confidentiality restrictions. Other information – especially detailed costs – is available to participants in the regulatory process but not to the general public.

Methods and techniques to estimate costs to customers: N/A

Quality, accuracy, and reliability of estimation: N/A

Availability of documentation: N/A

Table 6-2. Availability of economic information related to cost recovery

Utility	Precipitating Event	Trans. System Costs	Dist. System Costs	Gen. System Costs	Increased Customer Service Costs	Other Costs	Comments
San Diego Gas & Electric	2007 Southern California wildfires	○	○	○	○	○	The costs submitted to the CPUC for recovery were primarily associated with the utility's legal costs.

The Commission ruled in 2017 that the utility could not recover the requested $379 million from its customers (CPUC 2017a). SDG&E unsuccessfully appealed this decision to a state appellate court and the California State Supreme Court, and in April 2019 filed an appeal with the U.S. Supreme Court (SDG&E 2019c).

6.3 Preparing for the future

Upgrading infrastructure, maintenance, and readiness standards

As suggested above, California has detailed, extensive rules and regulations for electric utilities regarding overhead power lines and fire safety are detailed and extensive. GO 95 (design and construction rules for overhead power lines) is ~600 pages (CPUC 1941). The current requirements for California's regulated utilities' wildfire prevention and mitigation planning comprise the CPUC regulations developed over the years – especially during the past decade – expanded to encompass the recent state legislation, SB 901.

As we noted, the 2007 San Diego fires initiated intensive, expansive changes to the technical and operational requirements for California utilities' management and mitigation of wildfire risk, and implementation in practice, that are still unfolding. The text of key provisions in recent state legislation, SB 901, is presented in the Technical Appendix, which provides a synopsis of the current California regulatory framework for electric utility wildfire prevention. For the most part, the law's 20 provisions have two broad themes: (1) anticipating and minimizing wildfire risks, and (2) effectively responding to wildfire emergencies when they occur.

In regard to anticipating and minimizing wildfire risks, SB 901 explicitly calls for risk analysis and management, distinguishing risks associated with the design and construction of utility infrastructure from those associated with climatological and topological factors. SB 901 also requires planning for vegetation management and system inspection. In addition, it requires documentation of each utility's actions to improve the fire safety of its physical systems "…including hardening and modernizing its infrastructure with improved engineering, system design, standards, equipment, and facilities, such as undergrounding, insulation of distribution wires, and pole replacement" (item 12).

In the second category, effectively responding to wildfire emergencies when they occur, SB 901 includes protocols for de-energizing parts of a utility's system during a wildfire and notifying affected customers, ensuring the presence of a sufficiently large and well-trained workforce to restore service following a wildfire, and compliance with CPUC rules for emergency customer service.

SB 901 also requires that a utility's wildfire management plan document "metrics…used to evaluate the plan's performance and the assumptions [underlying them], and how the use of metrics identified in previous fire prevention plans has informed…[the utility's wildfire management plan]" (items 4 and 5).

SDG&E filed an updated Fire Prevention Plan in October 2018 and revised this into its first wildfire management plan to comply with the new law, which it submitted to the CPUC in February 2019 (SDG&E 2018, 2019a). As the utility characterized these two plans, "Both describe SDG&E's three prong approach to wildfire mitigation under the general areas of: operations and engineering, situational awareness and weather technology, and customer outreach and education" (SDG&E 2019a). Among the key new elements in the wildfire management plan are the inclusion of metrics, more extensive risk analysis, and discussion of intra-utility organizational and management aspects of wildfire mitigation. The contents of SDG&E's wildfire management plan are included in the Technical Appendix. They generally reflect the basic themes of SB 901 noted above: anticipatory wildfire risk management and effective emergency response when fires occur.

As discussed earlier, analyzing and mitigating the risks of wildfires incorporates procedures and methods for risk-based decision-making developed by the CPUC, the utilities, and other stakeholders. These are the outcome of the "Risk Assessment Mitigation Phase (RAMP)" and the "Safety Model Assessment Proceeding (S-MAP)." During RAMPs utilities create and use risk analysis and management techniques and frameworks; during S-MAP, the CPUC reviews the quality and suitability of these tools.

Although not originally aimed at wildfire risks *per se*, these Commission activities have had increasing importance for this purpose.

These activities are reflected in SDG&E's 2019 plan. The utility's risk analysis and management framework (which it uses in a range of decision-making contexts) is shown in Figure 6-2**.** It was developed in the course of the CPUC RAMP and S-MAP proceedings mentioned above. The framework is modeled after the International Organization for Standardization 31000 risk management standard. SDG&E's conceptual template for analyzing wildfire risks is shown in Figure 6-3.

Figure 6-2. San Diego Gas & Electric risk management process

Source: SDG&E 2019a.

Figure 6-3. San Diego Gas & Electric wildfire risk "bow tie"

Source: SDG&E 2019a.

SDG&E's 2019 wildfire management plan also addresses climate change adaptation in relation to wildfire risk management, through improved operational response measures: meteorological operating conditions; wireless fault indicators on distribution circuits; and advanced weather station forecasting and integration into the utility's emergency planning and response. The plan suggested that the utility, by November 2018, has already replaced 45 miles of 69 kilovolt transmission lines and 516 structures, and 18 miles of 12 kilovolt distribution lines and 302 structures with steel in the Cleveland National Forest (SDG&E 2019a). The plan was accepted by the CPUC in June 2019 (CPUC 2019b).

The CPUC also instructed SDG&E and other California energy utilities to implement a "multi-attribute value (MAV) function" technique, which weights and aggregates potential consequences of events such as wildfires into a single measure (CPUC 2018d). California electric utilities are required to submit post-fire reports in a specific format to the CPUC; details are discussed below.

Economic benefits—*avoided customer interruption costs*

SDG&E's 2020 wildfire mitigation plan (SDG&E 2020) includes a MAV function assessment of risk as part of the utility's overall risk management process. The "attributes" are safety, reliability, and financial. The potential effects of a given potential wildfire event – such as an ignition in a particular place – are quantified along these three dimensions, and a risk score is assigned that is a weighted sum of the attribute-specific measurements, constituting a form of expected value.

Prospective wildfire mitigation measures are then evaluated in terms of how much they could be expected to reduce this risk. This reduction divided by the cost of the measure is called the "risk-spend efficiency," and is key in guiding the utility's decision-making on wildfire safety investments. The “benefits” of different investments are defined as their risk-spend efficiencies, which are used to rank and compare the investments.

Along the financial dimension, potential risk attributes include possible property damage or loss of life from a wildfire event. In its most recent report to the CPUC on its risk-management methods and practices, SDG&E also states that

> Additional information considered in the creation of Risk Quantification Framework weights was to utilize an industry-leading study that comments on financial equivalences with reliability. The study considers the amount of financial loss to customers due to loss of electric power…because every electric outage is unique, the study is used as a guide rather than as a source of precise equivalences (SDG&E 2019d).

The study in question was on avoided costs, and was issued by Berkeley Lab (Sullivan et al. 2009). The documentation does not explain precisely how this information was used – what “used as a guide” means. However, it does indicate that the avoided cost concept and quantitative estimates have in some form been incorporated by SDG&E. [38]

In January 2020 the CPUC passed a formal resolution to develop and implement updated procedures for its Wildfire Safety Division to review IOUs’ wildfire mitigation plans, and in June 2020 the Commission passed another resolution establishing guidelines for the plans (CPUC 2020a, 2020b). These guidelines highlight the importance of utilities’ estimating and applying risk-spend efficiencies in wildfire mitigation planning. In June 2020 the Commission evaluated SDG&E’s and the other IOUs’ wildfire mitigation plans under these guidelines; among the “deficiencies” identified was a lack of detailed information on risk-spend efficiencies. The new procedures entail a formalized process through which the utilities’ correction of these problems can be guided and measured, and the wildfire mitigation plans, including SDG&E’s, were accepted under conditions including the improvement of risk-spend efficiency analysis and documentation.

The use of risk-spend efficiencies as described above can be considered a form of cost-effectiveness, rather than cost-benefit, analysis. As noted above, this approach includes application of the “reasonableness” standard, under which the benefits of measures to mitigate wildfire risks are determined by the regulators’ judgment (informed by extensive input from technical experts and others) . It is to be expected that, given the new stipulations of SB 901, the interpretation and implementation of this standard will be carefully examined by the CPUC.

[38] We note that evaluating one of the protocols identified in SB 901 – de-energizing parts of the utility system during times of extreme fire risk – would involve using customer interruption costs as one of the cost categories of the mitigation strategy. One benefit of this strategy would involve monetizing the avoided damage to property, etc. had a wildfire actually occurred. This is a different estimation approach from other utility strategies in which avoided customer interruption costs are often considered a benefit.

In a recent report, the CPUC's Safety and Enforcement Division and CAL FIRE (CPUC and CALFIRE 2018) discuss the challenges of standard CBA in the context of wildfires. The two agencies analyzed a proposal to develop a high-resolution fire-wind map to support the development of fire-wind loading standards for electric power infrastructure and accompanying regulations. CPUC and CAL FIRE (2018) stated that there are: "…a multitude of reasons why a traditional cost-benefit analysis is not feasible, primarily because there is no agreed upon or widely accepted cost-avoidance model that could be applied to catastrophic utility-caused wildfires. A cost-avoidance model for catastrophic wildfire would need to be scoped and developed to adequately quantify and assess the monetary benefit gained by reducing the likelihood of failure or ignition associated to any new regulation." The report included a qualitative, narrative discussion of the potential benefits of the maps.

Methods and techniques to estimate costs to customers: N/A

Availability of documentation: N/A

Economic benefits—*avoided regional economic impacts*

Although there may have been studies of the impacts of the 2007 wildfires on the San Diego or Southern California regional economy, we found no studies of the broader economic impacts of the resulting power interruptions.

Quality, accuracy, and reliability of estimates: N/A

Availability of documentation: N/A

Economic benefits—*other avoided societal impacts*

Interestingly, the CPUC (2019a) has stated that: "…the [utilities] did not provide firm estimates of [their] costs and savings associated with [implementing the new wildfire mitigation rules]. We conclude that a net increase in costs, if any, will be more than offset by the substantial public-safety benefits from [the rules]." Despite this comment, there are no known studies that assess the monetary value of public safety benefits from avoiding utility-caused wildfires in the first place – or the resulting societal value of avoiding the power disruptions that follow.

Methods and techniques to estimate other avoided societal impacts: N/A

Quality, accuracy, and reliability of estimates: N/A

Availability of documentation: N/A

Table 6-3. Availability of economic information related to mitigating future customer and regional impacts

Organization	Precipitating Event	Avoided Customer Interruption Costs	Avoided Regional Economic Impacts	Other Avoided Societal Impacts	Other	Cost-Effectiveness Analysis?	Cost-Benefit Analysis?	Comments
San Diego Gas & Electric	2007 Southern California wildfires	◒	○	○	○	**Yes**	**No**	Risk-management framework has been developed that draws on Berkeley Lab avoided cost estimates; regulatory staff considered economic benefits of fire prevention measures to be unquantifiable.

6.4 Discussion

Process and institutional aspects of preparedness and recovery planning

"Resilience" is mentioned very seldom in the regulatory records and documents that we reviewed for this case study. As noted earlier, this case study differs from the others in this report in the nature of the event and its consequences although it parallels the other case studies in illustrating the centrality of regulatory processes and their adversarial nature in cost recovery and preventive investment proceedings. California's processes and procedures for electric utility policy and regulation are in general quite complex, and wildfire risk management and response are no exception. The core regulatory activity is the General Rate Case, which determines electricity rates, charges, and utilities' returns on equity. General Rate Case proceedings are also the mechanism for evaluating and approving or disapproving potential investments in infrastructure and recovery of other expenditures (such as those for responding to wildfires) through rates, and other related matters. Many other CPUC activities are organized around (1) *Rulemakings*, which develop solutions to particular regulatory problems (such as setting standards for wildfire prevention); (2) *Investigations*, which examine particular events (such as the causes of a specific wildfire); or (3) *Applications*, in which the Commission reviews and decides upon utilities' petitions (e.g., for approval of certain expenditures such as wildfire cost recovery). The Commission has a large staff and includes a Safety and Enforcement Division, which provides technical expertise, and an Office of Ratepayer Advocates, which represents the interests of utility customers.

The adversarial nature of the regulatory process is illustrated by the fact that General Rate Cases begin with a utility filing its rate application with the Office of Ratepayer Advocates, which is charged with representing ratepayers, whose interests are usually seen as differing considerably from those of the utilities and their shareholders. After the initial filing, stakeholders and interested parties can and do participate in the proceedings (as well as in rulemakings, investigations, and applications). There is an interesting parallel between the California process and the New York process following storm Sandy, in that numerous issues disputed by the utilities and the counter-parties are ultimately resolved through "settlement agreements" negotiated between them, and proposed solutions submitted to the full CPUC for decision. The subjects of these negotiations can be highly technical and often draw upon significant expertise outside the utilities themselves. Noteworthy examples are the S-MAP and RAMP proceedings described above. All of these processes and types of proceedings have addressed, and continue to address, management and effective response to wildfires in California, in terms of engineering, operations, finances, and other aspects.

How the findings relate to previous work

Extensive efforts by SDG&E, the CPUC, and other stakeholders to develop and implement wildfire risk analysis and management systems methods have drawn on various previous work. The pragmatic details of these risk analysis and management systems and the ways in which they are used continue to evolve. The outcomes of these efforts will likely include valuable lessons for other regulators and utilities addressing fire risks across the Western U.S.

Additional commentary on economic data and methods

The overall process of identifying and quantifying wildfire risks, developing potential investments and measures to address these risks, and considering investment costs and outcomes is broadly parallel to the processes for dealing with extreme weather risks that are the subject of our other case studies. However, in this case there is a fundamental difference in the relation between the risks, and the utility and its management of them. Here, the issue is physical and other damage (including potential loss of human life) caused by the utility's infrastructure and its operational actions, rather than economic losses from power interruptions. Because wildfire risk can never be completely eliminated, there is thus a question of risk allocation – assignment of legal liability – for damage and harm caused by severe wildfires.

The 2018 Camp Fire resulted in the bankruptcy of Pacific Gas & Electric Company, which serves northern and central California. Potential future catastrophic fires arguably pose a threat to the traditional underlying business and regulatory models for energy utilities in the state. Accordingly, addressing the liability issue is currently one of the state's highest priority policy and regulatory problems.

By contrast, while hurricanes may cause severe to catastrophic physical damage and loss of life, these outcomes are not precipitated by utility infrastructure *per se*. In addition, LDWIs result in economic losses to a utility, its customers, and the local or regional economy in which it operates. As an example, cost-recovery proceedings in hurricane cases invariably include protests regarding whether a utility should be allowed to recover its costs from its ratepayers, and the utility petitions are not always approved.

In the SDG&E case, we found that customer avoided costs inform wildfire mitigation planning, but the details of their use are not clear. SDG&E and other California utilities have not used estimates of broad economic impacts of the power interruptions associated with wildfires. These findings are in contrast to the private costs of the 2007 wildfires for which SDG&E was found liable. Furthermore, the CPUC's opinion that the increase in costs associated with SDG&E's (and other utilities') complying with new, more stringent wildfire safety regulations would be exceeded by the "substantial public safety benefits" that they would provide.

Although the issue in this case study does not directly pertain to the costs of power interruptions, estimating the potential and total monetary benefits of measures to reduce the risks of fires caused by utility infrastructure is a challenging problem. Although SDG&E is developing the capacity to make certain types of these estimates under evolving regulatory requirements, improving and expanding the availability of methodologies for assessing the economics of wildfire mitigation is an important research frontier in California and other parts of the U. S. that face increasing wildfire risk. This type of research would include methods for estimating the economic impacts from – among other things – de-energizing lines and any avoided damage to public and private infrastructure from this risk mitigation strategy.

7. New Hampshire

7.1 Background information

7.1.1 Utility and regulatory body

Unitil Energy Systems, Inc. (UES, a subsidiary of the Unitil Corporation, was formed when two former subsidiaries of Unitil – Concord Electric Company and Exeter and Hampton Electric Company – merged in 2002. As an electricity distribution utility, UES serves more than 72,500 retail customers (approximately 11% of New Hampshire's total customers) based in the state's Seacoast and Capital regions. UES is one of four electricity distribution utilities in New Hampshire. The parent company, Unitil Corporation, provides both electricity and natural gas services in New Hampshire, Maine, and Massachusetts. The majority of Unitil Corporation's electricity service is delivered throughout New Hampshire.

UES is regulated by the New Hampshire Public Utilities Commission (NHPUC. The NHPUC's mission is to ensure customers safe, adequate, and reliable services at reasonable rates. The Commission has general jurisdiction over electricity, natural gas, water, and sewer utilities for issues such as rates, quality of service, finances, accounting, and safety. It also has limited jurisdiction over telecommunications. In New Hampshire, electricity customers can decide whether to purchase power from the utility or from a competitive energy supplier, with the latter offering a wider variety of plan options. The recipient of the energy portion of a customer's electricity bill is thus up to the customer, but the delivery portion of the bill always goes to the distribution utility that actually delivers the electricity.

New Hampshire is one of the six New England states served by ISO New England (ISO-NE), the independent, non-profit, regional transmission organization authorized by the Federal Energy Regulatory Commission (FERC. ISO-NE fulfills three critical roles; operating the electricity grid, administering a competitive wholesale electricity market, and planning the power system to maintain "the constant availability of competitively-priced wholesale electricity."[39]

7.1.2 Precipitating event

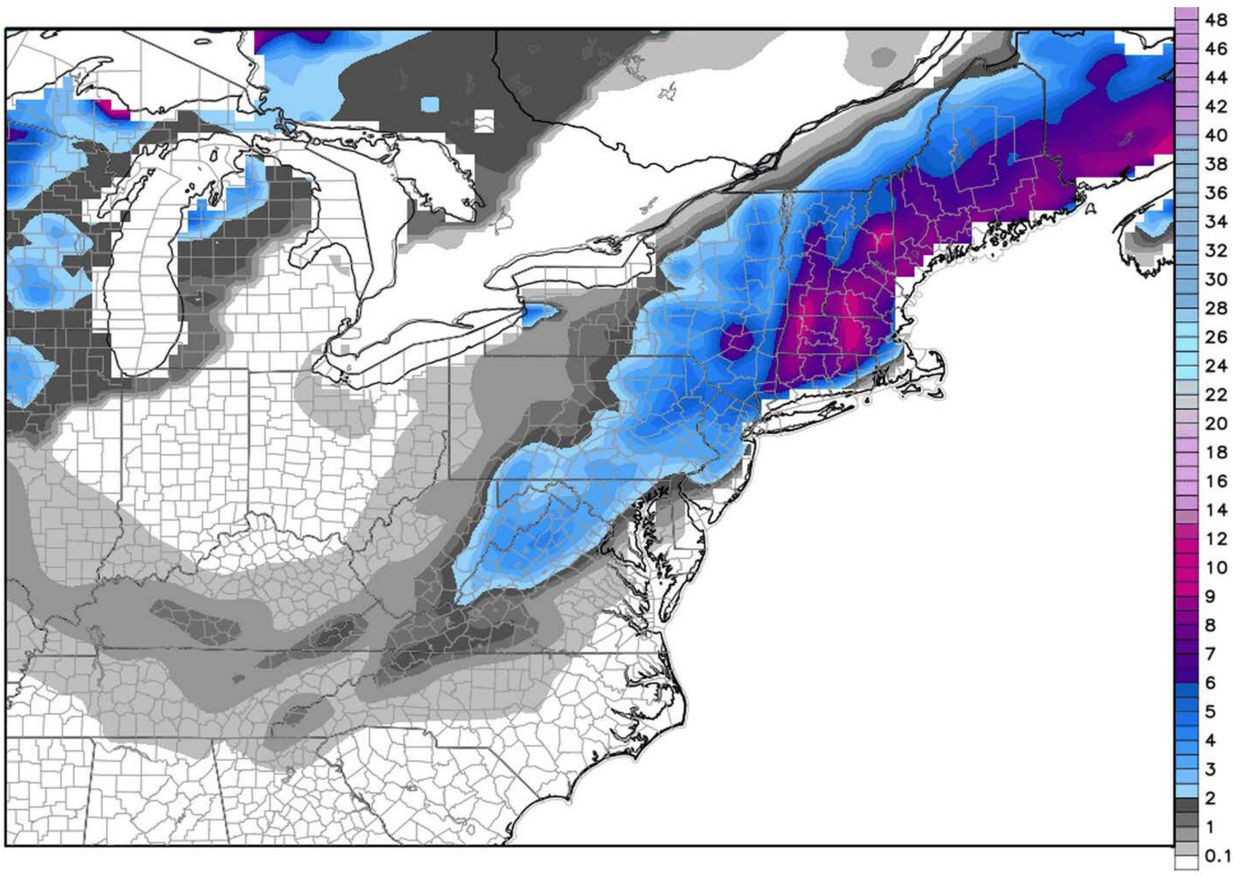
During the winter, New Hampshire often experiences ice, snow, and/or wind storms that impact the electricity system. In 2008, a severe ice storm in New England resulted in widespread power outages. In late October 2011, New Hampshire experienced the fourth in a string of powerful storms, which led to widespread damage and prolonged outages caused by a combination of heavy, wet snow; high winds; and abundant foliage still on trees (NHPUC 2012). The October 2011 nor'easter resulted in more than 300,000 customers being without power, making it the third-largest outage event in the state's history after the December 2008 ice storm and a February 2010 wind storm. Following the storms of October 2011, a powerful snowstorm hit the state during Thanksgiving 2014 and left more than 238,000 customers without power. Although this snowstorm ranked as the fifth-largest power outage

[39] Adapted from ISO-NE website: https://www.iso-ne.com/about/what-we-do/three-roles

event in the state's history since 2008, it was the first widespread emergency storm event to afflict New Hampshire during a major holiday (NHPUC 2015). Figure 7-1 shows the snowfall accumulations during the 2014 Thanksgiving snowstorm, and Table 7-1 gives a chronology of these major storms and the regulatory and utility responses to them.

New Hampshire was also affected by tropical storm Sandy in 2012 and tropical storm Irene in 2011. However, the impacts of these summer storms were less severe in New Hampshire than in states further south along the Eastern Seaboard, and winter storms remain the primary weather-related risk to New Hampshire's electricity system.

Figure 7-1. Regional snowfall accumulations from the 2014 Thanksgiving snowstorm (Washington Post 2014)



7.1.3 Regulatory and policy responses

In 2002, the NHPUC transferred the responsibility for electricity-system safety to its Safety Division. The Safety Division is in charge of coordinating service restoration with electric utilities during major outages, and it also plays the role of "monitoring around-the-clock emergency response efforts coordinated by the State of New Hampshire for local municipals."[40] Since the ice storm in December

[40] Information from NHPUC Safety Division's website: https://www.puc.nh.gov/Safety/Electrical%20Safety%20and%20Reliability.html

2008, the NHPUC has initiated extensive post-storm reviews to “assess utility preparedness and emergency response capabilities in New Hampshire” (NHPUC 2012). Reports that address individual storms can be found on the NHPUC’s website under the heading “Electrical Safety and Reliability.” These comprehensive documents include reports specifically related to the December 2008 Ice Storm, October 2011 Snowstorm, and an after-action report from the 2014 Thanksgiving snowstorm. Each assessment covers the planning and preparedness of each utility, its restoration response, and its communication with customers (NHPUC 2009, 2012, 2015).

The New Hampshire Code of Administrative Rules Chapter PUC 300 (Section 300) addresses rules for electricity service. In contrast to the Florida, New York, and Texas cases presented in this report, Section 300 never explicitly mentions the term “hardening.” Section 300 does include regulations regarding emergency response and electrical infrastructure reliability. According to Section 306.09, Emergency Response Standards and Electrical Outage Restoration, each utility is required to file an emergency response plan (ERP) with the commission. Section 307.07 lays out detailed requirements for reliability reporting, and Sections 307.09 and 308.18 require utilities to file quarterly reports of reliability measures that meet certain standards (NHCAR 2014). We cannot identify any specific clause requiring electric utilities to submit annual reports about their vegetation management programs or reliability enhancement plans. However, some utilities file such reports pursuant to rate change settlement agreements with the NHPUC. For example, per the settlement agreement for a UES rate case (Docket No. 10-055), UES was required to implement a reliability enhancement program and an augmented vegetation management program beginning in calendar year 2011 (NHPUC 2010).

Table 7-1. Time frame of storms, regulatory responses, and utility activities

Timeframe	*Event and activity*
2002	● Concord Electric Company and Exeter and Hampton Electric Company merge into Unitil Energy Systems, Inc.
2008 – 2009	● Ice storm impacts New Hampshire in December and results in the largest power outage event in state history. ● NHPUC initiates an extensive after-action review culminating in the December 2008 Ice Storm report.
2010	● A wind storm hits New Hampshire in February and results in the second-largest power outage event in the state history.
2011	● UES starts implementing a reliability enhancement program and an augmented vegetation management program. ● A nor'easter storm hits New Hampshire in late October and results in the third-largest power outage event in state history. ● NHPUC initiates an extensive after-action review culminating in the October 2011 Snowstorm report.
2014	● A snowstorm hits New Hampshire during the Thanksgiving holiday and results in the fifth-largest power outage event in state history. ● NHPUC initiates an extensive after-action review culminating in the After-Action Report for the November 26, 2014 Thanksgiving Snowstorm.
2016 – 2017	● UES files a petition for a distribution rate increase on March 30, 2016 (Docket No. DE 16-384). ● Order is approved on April 20, 2017, with the settlement agreement providing for step adjustments to the distribution rate on May 1 in years 2017, 2018, and 2019.
2017 – 2018	● A storm with high winds hits New Hampshire in October 2017 and causes the fourth-largest power outage event in state history. ● NHPUC initiates an extensive after-action review culminating in the October 2017 Wind Event After Action Report.
2019	● UES files a petition on February 28 (Docket No. DE 19-043) entitled "Step Adjustment and Proposed Changes to the Storm Recovery Adjustment Factor, effective May 1, 2019," pursuant to DE 16-384. ● NHPUC issues an order on April 22 authorizing UES to implement a step increase in the distribution rate, effective for services rendered after April 30, 2019.

7.2 Event response and immediate recovery

Engineering and operational elements

The October 2011 Snowstorm report contains detailed information about the number of days and hours during which each community in the UES service territory went without power. At its peak, UES had 51,262 customers without electricity, which represented 69% of its total number of customers (NHPUC 2012).

In 2017, UES reported the total number of outages, peak number of outages, total customers interrupted, peak customers interrupted, and percentage affected at peak for both the Seacoast and Capital regions (UES 2018a).

In January 2019, NHPUC's Safety Division summarized the impacts of nine of New Hampshire's most widespread storms on its four distribution utilities (NHPUC 2019a). For each storm, the information includes number and percentage of customers affected, duration of restoration, number of restoration crews, wire reattached/replaced (in feet), number of transformers replaced, number of poles set, and number of cross-arms replaced.

Cost recovery

Two major mechanisms in New Hampshire provide for storm cost recovery: (1) the Storm Recovery Adjustment Factor (SRAF); and (2) the Major Storm Cost Reserve (MSCR). These two mechanisms are closely related and crucial to a utility's cost-recovery procedure. The SRAF mechanism was designed to adjust rates to distribution service customers to recover storm costs. The MSCR, an accounting mechanism, was approved by the NHPUC and provides for the recovery from customers of a specified annual amount in distribution rates to offset costs incurred in events that qualify as major storms. The MSCR fund also allows a utility such as UES to recover costs incurred to prepare for major forecasted storms. After the UES Rate Plan Settlement (Docket No. DE 10-055) and UES's Petition to Increase Storm Recovery Adjustment Factor (Docket No. DE 11-277), an order titled Order Granting Increase to Storm Recovery Adjustment Factor (SRAF) (Order No. 25,351, which is within the DE 11-277 filing) requires that UES "file annual reports to the Storm Reserve Fund and storm recovery updates for those storms where costs are recovered through the SRAF" (NHPUC 2010, 2011, UES 2018a).

In early 2019, UES petitioned for step adjustments to its distribution rates and offsetting reductions in the SRAF charge (Order No. 26,236 affiliated with Docket DE 19-043). This filing is pursuant to a settlement agreement approved in Order No. 26,007 in UES's previous distribution rate case (Docket No. DE 16-384). The petition was approved by the NHPUC (2019b). The order suggests that as a result of the combination of the step increase in distribution rates and the change in SRAF, a typical residential customer using 600 kWh per month would see a monthly bill decrease of 7 cents (a drop of 0.1%).

Categories of expenses: UES's MSCR Fund Report of 2017 documents the qualifying costs charged to the storm reserve. The cost categories include payroll, materials & supplies, transportation, contractor invoices, and other. UES reported expenses separately for each storm that qualified to be recorded.

Among the three storm reports provided by NHPUC (2009, 2011, 2014), the report about the 2014 Thanksgiving storm is the only one that includes a section titled *Utility Expenditures*, which details historical storm restoration costs. After collecting data from all New Hampshire utilities, the NHPUC estimated that total expenditures for storm restoration amounted to $38 million (NHPUC 2015). Based on this analysis, the NHPUC concluded that the 2014 Thanksgiving storm was the second-most-expensive weather event to affect the state's electricity system. As of January 2019, the Safety Division of NHPUC had summarized the total cost for each utility (NHPUC 2019a) for nine of the most severe weather-related outages since 2008.

Accounting procedures: As mentioned above, the MSCR procedure was implemented to calculate the change in distribution rates for cost recovery following major storms. As of May 1, 2019, the amount to be added annually to the fund to support storm recovery is $800,000. This level reserve is meant to cope with storms that are frequent and generally not considered to be extraordinary in magnitude (NHPUC 2019b).

Methods and techniques to estimate costs to utilities: In its annual reports on the MSCR Fund, UES includes the costs of each storm in a particular year along with a breakdown according to the types of expenses (UES 2018a, 2019). The ERP points out that utility's Finance Unit Lead (FUL) provides the cost estimates. The FUL ensures the cost tracking process, issuing petty cash and procurement cards, and ensures cost controls are in place for subsequent payment of vendors and external resources (UES 2015). Prior to an impending event, the FUL issues appropriate accounting information for resources and materials to each of the affected regions based on existing regulatory accounting requirements and procedures. The FUL also produces daily estimates throughout the restoration process.

As discussed earlier, the MSCR fund is used for costs associated with recovering from qualifying major storms. A qualifying major storm is defined as a weather event that causes 16 "concurrent troubles" (no precise definition of this phrase can be found in the source document) and at least 15% of customers to be interrupted, or 22 concurrent troubles in either the Capital or Seacoast regions of UES (NHPUC 2011). Designation of a qualifying major storm permits utility costs associated with storm planning and preparation activities to be included. Planning and preparation activities include pre-staging of crews, standby arrangements with external contractors, and incremental compensation of employees. UES uses the power disruption index from its weather forecaster to determine whether a storm can qualify as a major storm.

The 2014 Thanksgiving Snowstorm report does not specify the methods used to estimate the utilities' expenditures. The NHPUC presents the cost of each storm event to each utility in terms of "average cost per customer affected" and "average cost to restore power" (NHPUC 2015).[41] The former was derived by "taking the total storm restoration costs divided by the number of customers affected by loss of power, per storm, as reported by each utility," and the latter was presented as the average cost per hour for power restorations during each storm, derived by "taking the total costs per storm restoration, as identified by each utility divided by the total hours of duration for each utility to restore all customers affected during the storm event." The report defined the total hours of restoration to be the time span between the onset of the storm and the power restoration time of the last customer. The average cost per crew assigned was also calculated using similar methods. All of these measurements can be calculated easily based on primary data that are collected and reported by the utilities.

Quality, accuracy, and reliability of estimates: No disaggregated economic impacts are presented in the NHPUC's post-storm reports for 2008 and 2011 storms. Only an aggregate total economic cost, which covers direct costs incurred by all utilities for storm recovery and restoration, is reported for the 2014 Thanksgiving Snowstorm. Records of how accurate the utilities' forecasts were, and utilities' approaches for estimating restoration times, are comprehensive and detailed. In addition, UES provided detailed costs incurred due to each storm in a given year.

Economic impacts can be assessed by evaluating changes in customer electricity rates — or SRAFs, which are approved to allow the utility to recover its storm costs — by multiplying the SRAF by the electricity usage of UES's commercial, industrial, and residential customers.

Availability of documentation: The rate change and SRAF change petitions filed by UES can be found in the NHPUC virtual filing system (UES 2019). Detailed reports evaluating the utility's preparedness and responses to storms are available on NHPUC's website. UES's petitions for changing distribution rates can also be found on NHPUC's website for specific filings (NHPUC 2010, 2011, 2019b).

Table 7-2. Availability of economic information related to cost recovery

Utility	Precipitating Event	Trans. System Costs	Dist. System Costs	Gen. System Costs	Increased Customer Service Costs	Other Costs	Comments
Unitil Energy Systems	Severe fall and winter storms	N/A	●	N/A	○	○	

[41] NHPUC also summarizes the direct costs that customers incurred in a storm. In the October 2011 Snowstorm report, NHPUC staff summarize the possible personal costs incurred as follows: "For residential customers, those costs are driven in part by: the purchase of fuel for generators; lodging and meals for those who cannot remain in their homes; lost wages for those who work from home; and spoiled food with the loss of refrigeration. Business customers experienced revenue losses, as well. Without electricity, many customers in New Hampshire lack water, as well as heat" (NHPUC 2012).

Outcome of cost recovery request

On April 15, 2019, NHPUC issued an order (within Docket 19-043) approving UES' petition of step adjustment and changes to the SRAF, effective May 1, 2019. The petition consisted of two components: (1) seeking approval of proposed tariffs to implement step increase with effective rates of May 1, 2019; (2) requesting approval of the SRAF be adjusted to reflect the full recovery of costs incurred from the December 2008 ice storm and the February 2010 wind storm, and the shift of cost recovery for 2018 Winter Storm Quinn from the MSCR fund to the SRAF. The NHPUC approved UES's proposed methodology and calculation of the step increase. The Commission also approved the end of the recouping of costs of the December 2008 ice storm and February 2010 wind storm through SRAF, effective with May 1, 2019 rates and the shift of cost recovery of 2018 Winter Storm Quinn from the MSCR to the SRAF. The NHPUC claimed in its order that the resulting rates were "just and reasonable" (NHPUC 2019b).

7.3 Preparing for the future

Upgrading infrastructure, maintenance, and readiness standards

After a wind event in October 2017, UES reported that it replaced 4,709 feet of wire, 17 poles, 28 cross arms, and 40 transformers in the Seacoast and Capital regions (UES 2018b). The report specified the numbers of infrastructure items replaced, but *there were no details about whether the utility upgraded these infrastructure items or replaced the damaged components based on a higher standard.*

As mentioned above, Section 306.09 of the New Hampshire Code requires each utility to file an annual ERP. The ERP rules dictate that "one full readiness exercise and one table top exercise be conducted annually." Projected events are to be categorized into ERP Event Levels 1–5, based on the percentage of customers experiencing outage and the associated durations of power disruptions. According to UES's ERP, distinctive actions should be implemented in preparation for, and in response to, events of different levels, and procedures for conducting damage assessments vary among different levels of events. For example, for level 1–3 events, calculation of estimated times of restoration is coupled to the outage management system and varies based on event level and corresponding decentralization level. For events of level 4 or 5, the estimated restoration times calculated by the outage management system may be modified by central electric dispatch (UES 2015).

When it comes to reporting reliability metrics, Section 307.09 mandates that a utility must report CAIDI, SAIFI, SAIDI, and the average number of customers without power per interruption event.

Following a 2010 filing, the Settlement Agreement provided that UES must file an annual reliability enhancement plan (REP) and vegetation management plan (VMP). The detailed reports are available (NHPUC 2010, UES 2015, 2017).

The NHPUC's reports evaluating utilities' preparedness for, and responses to, three major storms include findings about the utilities' adoption of pre-storm restoration prediction models, which play a critical role in determining storm resource requirements. Pre-storm restoration prediction models take utility-specific weather forecasts and estimated system impacts ("based on utility history and industry experience") as inputs. UES's pre-storm restoration prediction model uses National Weather Service forecast data and develops estimated impact indices. The resulting predicted scale of the utility response can be assigned to one of five different levels. This model also takes confidence levels of weather forecasts into account to determine estimated impact indices (NHPUC 2012). At the onset of an actual event, the estimated system impacts are refined based on actual field reports, and the number of labor hours for restoration will be reassessed. To enhance the efficiency of restoration work, crew arrival times are deliberately staggered. Based on damage predictions, UES also adopts a resource procurement planning method, which surpasses the standard estimation approach that depends solely on historical information.

Economic benefits—*avoided customer interruption costs*

UES's annual REP and VMP reports compare proposed budgets to actual costs incurred for activities such as cycle prune, hazard tree mitigation, forestry reliability work, mid-cycle review, police/flagger, core work, and vegetation management planning. The comparison also covers distribution costs such as vegetation program staff costs (UES 2017, 2018b).

Methods and techniques to estimate costs to customers: Neither NHPUC nor UES reports estimate avoided VOLL due to storm-hardening programs. In its 2016 annual report, UES contended that its REP and VMP have produced benefits for customers (UES 2017). The utility noted that there was a steady decrease in number of customers interrupted and number of tree-related incidents from 2012 to 2016. In addition, UES's outage management system, which details customer counts and protective devices, enables the company to estimate potential system reliability impacts. The 2016 outage management system can be used to estimate the number of customers affected, based on the locations identified for potential outages (e.g., the 2016 outage management system program identified a repair every 4.5 miles and an average of 830 customers affected by each potential failure event). The utility can further develop system reliability indicators, such as SAIDI, and thus benefit customers. The 2016 program showed a total opportunity for avoided SAIDI of 89.6 minutes, representing 60.5% of the company's 10-year average annual SAIDI of 148.0 minutes. Despite all its efforts to quantify projected improvements in reliability metrics, UES does not appear to have monetized these customer benefits in the manner necessary to incorporate them into cost-benefit analysis of storm-hardening and preparation programs.

Quality, accuracy, and reliability of estimates: The costs of reliability enhancement and vegetation management programs have been thoroughly documented. We could not locate any VOLL estimation criteria or calculations for a specific storm or series of storms, or a total for all storms in a year. UES made a convincing case in its annual report that its REPs and VMPs were benefiting customers by reducing interruptions from storm events (UES 2017). However, UES did not monetize these benefits to customers, which would generally require VOLL estimates. Given that UES does not present any formal cost-benefit or cost-effectiveness analysis of its reliability enhancement and vegetation management investments, it is not possible to determine whether these programs generate net economic benefits.

Availability of documentation: UES's annual reliability enhancement and vegetation management program reports can be found in the NHPUC virtual filing system (UES 2017, 2018b).

Economic benefits—*avoided regional economic impacts*

We could not locate any NHPUC or UES estimates of broader economic impacts avoided as a result of storm-hardening activities. Although after-action reports do not include estimates of storm impacts on gross state product, it is worth noting that NHPUC acknowledges some indirect economic impacts (NHPUC 2015): "Each hour without power negatively impacts the New Hampshire economy as well as has other negative socio-economic effects and safety impacts." However, there is no information available indicating how hardening activities have led (or may lead) to avoided regional economic impacts.

Quality, accuracy, and reliability of estimates: N/A

Availability of documentation: N/A

Economic benefits—*other avoided societal impacts*

We found no information in the public record detailing other avoided societal impacts.

Methods and techniques to estimate other avoided societal impacts: N/A

Quality, accuracy, and reliability of estimates: N/A

Availability of documentation: N/A

Table 7-3. Availability of economic information related to mitigating future customer and regional impacts

Organization	Precipitating Event	Avoided Customer Interruption Costs	Avoided Regional Economic Impacts	Other Avoided Societal Impacts	Other	Cost-Effectiveness Analysis?	Cost-Benefit Analysis?	Comments
Unitil Energy Systems	Severe fall and winter storms	○	○	○	○	**Yes**	**No**	

7.4 Discussion

Process and institutional aspects of preparedness and recovery planning

As suggested above, when the utility changes its distribution rates, rate increases can be offset by a reduction in the SRAF. To propose changes to the SRAF, the utility first needs to file a petition, which is usually pursuant to a previous settlement agreement approved by the NHPUC. A previous settlement agreement authorized UES to implement three annual step adjustments (on May 1 of 2017, 2018, and 2019). The aggregate total of step adjustments over these three years was not to exceed $4.5 million (NHPUC 2016). In addition, each step increase is based on UES's annual change in net utility plant (its net capital investments) from the prior year. Future petitions would be reviewed by NHPUC staff. More recently, UES filed a petition on February 28, 2019 regarding step adjustments and proposed changes to the SRAF. The NHPUC approved the petition on April 22, 2019 (NHPUC 2019b).

How the findings relate to previous work

Compared to the other cases being studied – where utilities face less frequent, but more extreme weather events – New Hampshire is affected relatively often by severe winter snow and ice storms. In a sense, the MSCR mechanism that is built into normal electricity distribution rates to raise revenue to offset storm recovery costs is a regulatory response to the frequent severe storms that impact this region.

UES's annual MSCR fund reports show detailed costs incurred for each storm event in a given year. For instance, the 2018 report contains cost details for about 10 storm events in that year, and one event in 2017 (UES 2019). In addition, NHPUC's Safety Division has provided comprehensive reports regarding each distribution utility's preparedness and response efforts for three of the most severe storms since 2008. The NHPUC is the only public utility commission we studied that has published reports evaluating utilities' prospective and retrospective actions for specific storms. Although these reports primarily emphasize utilities' preparation and response capabilities, rather than estimated direct/indirect economic impacts induced by storms or methods for developing these estimates, they offer insights into the methods that each utility employs for emergency planning and preparedness; weather forecasting; emergency and restoration response; and communications with the public utility commission and customers. By comparing the system reliability and restoration responses of the four New Hampshire utilities, the NHPUC reports highlight specific improvements utilities should incorporate into future planning. For example, the 2011 snowstorm report suggested that the three New Hampshire distribution utilities other than UES that are regulated by NHPUC should incorporate forecast confidence levels into their pre-storm restoration models, as already done by UES. These reports lay the groundwork for estimating the impacts of any preventive work.

The term *resilience* does not appear in either the New Hampshire Code of Administrative Rules for Electric Services or the NHPUC after-storm action reports. UES uses the word "resiliency" in its reliability enhancement and vegetation management program reports, but no definition of the term is given.

Additional commentary on economic data and methods

In the after-action report following the 2014 Thanksgiving snowstorm, NHPUC staff indicated that "after six historic wide-scale storms, there is no definitive specific report that quantifies the economic and social impact of wide-scale storm events for the businesses and citizens of New Hampshire." The staff recommended that the Commission form a committee with representatives from each utility to prepare such an economic report, but we could not locate a report of this type or any on-line documents to confirm that such a report was produced following this recommendation. Thus, although NHPUC staff perceived the value of such an economic impact analysis of power interruptions resulting from storm events, neither the utility nor the public utility commission estimates the direct/indirect economic impacts that power disruptions have on customers.

8. Maryland

8.1 Background information

8.1.1 Utility and regulatory body

Baltimore Gas and Electric (BGE is the largest gas and electricity provider in Maryland. Founded in 1816, it is now a subsidiary of the Exelon Corporation. BGE delivers electricity to more than 1.3 million customers, including both business and residential customers. BGE has approximately 1,300 miles of transmission lines and more than 25,000 miles of distribution power lines. BGE's service territory covers roughly 2,300 square miles, including the City of Baltimore and all or part of 10 central Maryland counties.

BGE is regulated by the Maryland Public Service Commission (MDPSC), which was established by the Maryland General Assembly in 1910. The Commission regulates gas, electricity, telephone, water, and sewage disposal companies. Beyond its role in setting utility rates, the Commission also deals with activities such as collecting and maintaining records and reports of public service companies, reviewing their plans, inspecting equipment, auditing, and handling consumer complaints.

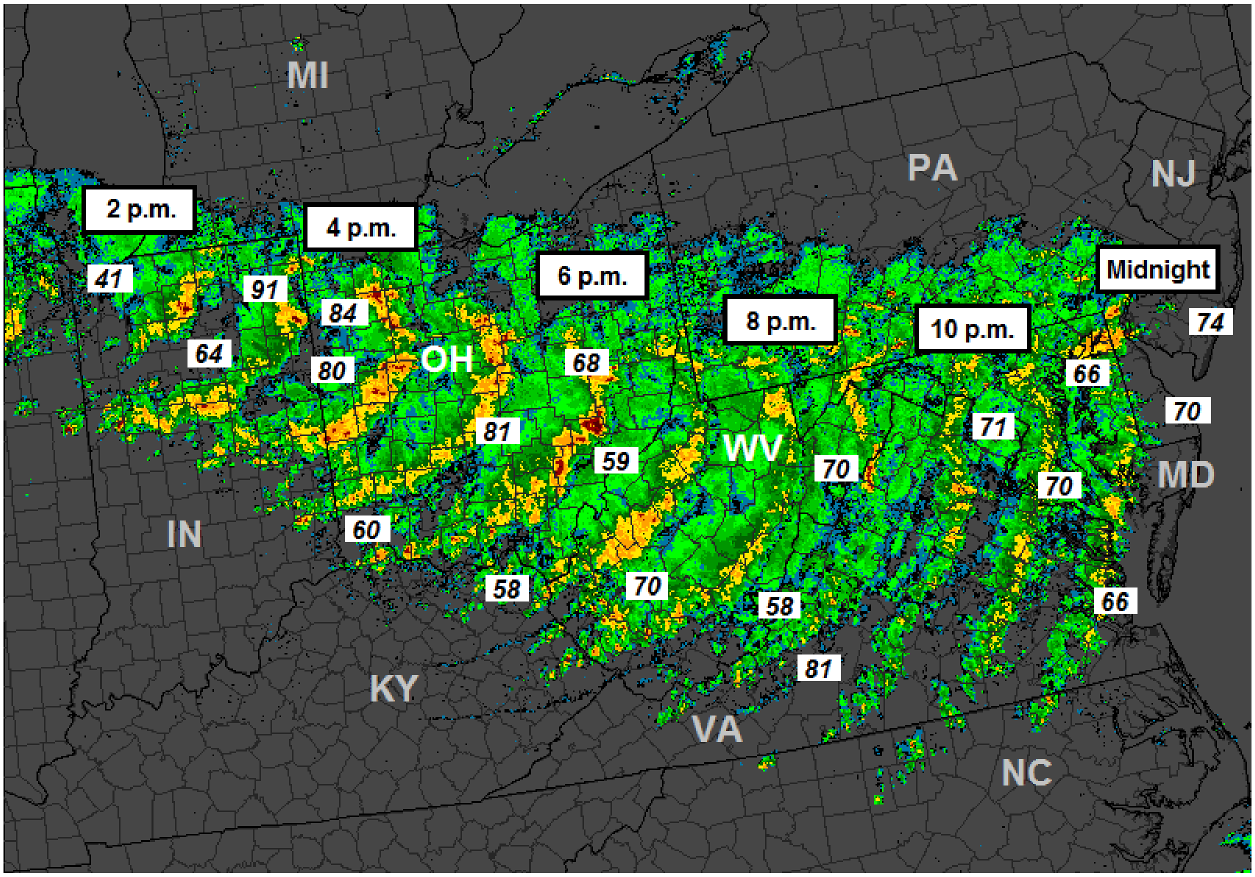
The electricity market in Maryland has a similar structure to the one in New Hampshire. The electricity transmission system and competitive wholesale market are operated by the PJM Interconnection, the regional transmission organization that covers all of Maryland and several neighboring Mid-Atlantic States, as well as parts of more distant states such as Illinois. Deregulation has separated generation and supply utilities from transmission and distribution utilities, with BGE belonging to the latter category. Electricity customers in Maryland have retail choice. They must pay the local electric distribution company for delivering electricity through its distribution system, but customers can choose to purchase their electricity from the utility or from a competitive retail supplier.

The Maryland Energy Administration (MEA), a state government office, plays a significant role in promoting "affordable, reliable and cleaner" energy for the state of Maryland. It advises the governor and general assembly on energy policies. MEA administers grant and loan programs to promote clean energy technologies in all sectors of Maryland's economy.

8.1.2 Precipitating event

A derecho is a storm with sustained winds in excess of 58 miles per hour coming from one direction along a relatively straight line. Wind gusts can exceed 100 miles per hour, and damage can extend more than 240 miles (MDPSC 2013a). On June 29, 2012, a major derecho traveled 700 miles and impacted the Ohio Valley and 10 Mid-Atlantic states as well as Washington, D.C. The hardest hit were Ohio, West Virginia, Virginia, Maryland, and Washington, D.C. (U.S. Department of Commerce, NOAA 2013). The derecho led to widespread power outages throughout the affected regions. In all, more than 4 million customers were left without power, and 13 deaths were directly attributed to the derecho, mainly caused by falling trees. The average BGE customer outage duration was 37.5 hours. All restoration work was completed within 8.5 days. The affected region was already experiencing a dangerous heat wave when the derecho struck, and this storm exacerbated that life-threatening situation. In areas without power because of the derecho, 34 heat-related fatalities were reported (U.S. Department of Commerce, NOAA 2013).

Figure 8-1. Hourly radar of the June 2012 Derecho event with wind gusts in miles per hour (NOAA 2019)



8.1.3 Regulatory and policy responses

The Code of Maryland Regulations (COMAR) contains Title 20, on the Public Service Commission, and Subtitle 50, on Service Supplied by Electric Companies. These sections include regulations that span both prospective and retrospective considerations for storm-induced power interruptions.

Section 20.50.07.06 deals with utility reporting of annual reliability indices. Each utility is required to submit an annual reliability report to the MDPSC on or before April 1, with the data used to generate the reliability report taken from the previous year ending December 31 (COMAR 2010). In terms of storm reporting, COMAR 20.50.12.13 requires a utility to file a written report with MDPSC within three weeks of the end of a major outage event (COMAR 2019).

RM43, which is a rulemaking revision for COMAR 20.50, was initiated by the MDPSC in January 2011 (MDPSC 2011) to provide reliability measurement. It established, for the first time in Maryland, vegetation management standards for distribution and transmission lines that are not regulated by FERC (Grid Resiliency Task Force 2012). RM43 set "minimum reliability metrics for each utility based on its past performance, established a mandatory annual performance reporting system, and set up a customer communication survey." In addition, RM43 requires utilities to develop vegetation management programs to meet the required technical standards, along with a vegetation management schedule.

Shortly after the June derecho, on July 6, 2012, the MDPSC initiated a comprehensive evaluation of utilities' preparedness for and responses to the storm, which was included in a case titled "In the Matter of the Electric Service Interruptions in the State of Maryland Due to the June 29, 2012 Derecho Storm" (Case No. 9298).

On July 25, 2012, Executive Order 01.01.2012.15 directed the State Energy Advisor, together with other agencies including MEA, to solicit expert recommendations on improving the resiliency and reliability of Maryland's electricity distribution system.[42] The Grid Resiliency Task Force was formed, and held eight roundtable discussions with almost 50 experts around the country over more than 60 days. The Task Force primarily evaluated:

- The effectiveness and feasibility of undergrounding supply and distribution lines
- Other options for infrastructure investments to improve resiliency of the grid
- Options for financing and cost recovery for capital investment

The Task Force drafted 11 recommendations (Grid Resiliency Task Force 2012). It defined "resiliency" as follows:

> Resiliency refers to the ability of the distribution system to absorb stresses without experiencing a sustained outage (i.e., over 5 minutes). These stresses may be in the form of hurricanes, high winds, snow, and high load days…any improvement that increases resiliency will necessarily reduce the frequency of outages during stress events, and may also decrease overall duration of the outage event.

The Task Force's recommendations were "informed by the foundational principles, guided by the data, and intended to be implemented in a cohesive manner." The Task Force considered technological solutions, infrastructure investments, regulatory reforms, and process improvements. It recommended the following:

- Improve RM43's reliability and reporting requirements
- Accelerate RM43's march toward reliability
- Allow a tracker cost-recovery mechanism for accelerated and incremental investments
- Implement a ratemaking structure that aligns customer and utility incentives by rewarding

[42] Adapted from the Grid Resiliency Task Force webpage: https://energy.maryland.gov/Pages/gridresiliencytf.aspx

reliability that exceeds established reliability metrics and penalizes failure to meet those metrics
- Perform joint state-utility exercises
- Facilitate information-sharing among utilities, state agencies, and emergency management agencies
- Increase citizen participation in list of special needs customers and share information with emergency management agencies
- Evaluate statewide vegetation management regulations and practices beyond RM43
- Determine cost-effective level of investment in resiliency
- Study staffing pressures due to graying of workforce
- Task the Energy Future Coalition with developing a pilot proposal "…on a viable method to explore the contours of the utility of the future."

More details from the Task Force report and how these recommendations have been implemented will be described in the following sections.

Table 8-1. Time frame of storms, regulatory responses, and utility activities

Timeframe	*Event and activity*
2011	• On January 12, MDPSC initiates revisions to COMAR 20.50, addressing the regulations on electric companies' proposed reliability and service quality standards (Admin. Docket No. RM43).
2012	• Derecho occurs on June 29. • On June 30, Governor O'Malley declares a state of emergency. • On July 6, MDPSC initiates the derecho case (Case No. 9298). • On July 25, Executive Order 01.01.2012.15 is issued and the Grid Resiliency Task Force is formed. • On July 27, BGE initiates an application to MDPSC for adjustment of its electric and gas base rates (Case No. 9299). • On October 25, the Grid Resiliency Task Force issues its *Weathering the Storm* report.
2013	• On May 31, BGE submits its Short-Term Reliability Enhancement Plan and Comments on Task Force Report. • On September 3, BGE submits its Comprehensive Long-Term Assessment & Staffing Analysis report.
2014 – 2018	• As part of a five-year plan known as the Electric Reliability Investment initiative, BGE submits its Annual Electric Reliability Investment Initiative Reports.

8.2 Event response and immediate recovery

Engineering and operational elements

As mentioned above, COMAR Section 20.50.12.13 requires utilities to report on major outage events (COMAR 2019). The written report is to include basic information about the utility (e.g., the total number of Maryland customers it serves), information about the outage (e.g., the date and time of the major outage event, the average duration of customer service interruption, and the total number of customer interruption hours), and information about requests for outside assistance. The regulation contains very specific requirements regarding the system damage measurements that utilities must include in their reports, such as numbers of the following activities that take place or are identified during system restoration:

- Poles replaced
- Distribution transformers replaced
- Fuses replaced
- Downed wires
- Substations with damaged equipment

In addition, the utility should provide a self-assessment, including lessons learned and future plans to improve service restoration efforts during major outage events; a description of the manner in which customers were informed of the status of the outages in their geographic areas through the customer call center or by other means of customer communication; a description of the manner in which the utility informed elected officials, government officials, and members of the public of the status of the outage and restoration efforts; a description of the manner in which the utility estimated restoration times; a description of any areas where the utility did not comply with its major outage event plan; and the number of customer service interruptions caused by each one of the following:

- Fallen tree or tree limb
- Fallen or broken pole
- Lightning damage
- Ice accumulation on conductors
- Each other direct cause of interruption of service to 5% or more of total customers interrupted[43]

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[43] With regard to annual reliability reporting, COMAR 20.50.07.06 demands that each utility calculate and report system-wide SAIDI, SAIFI, and CAIDI indices for its system consisting of all feeders originating in Maryland. In addition, a utility should also report district indices (for cooperatively owned utilities to report SAIDI, SAIFI and CAIDI for each operating district identified as having the poorest reliability), feeder indices (for investor-owned utilities to report SAIDI, SAIFI, and CAIDI for 2 percent of feeders or 10 feeders, whichever is more), poorest reliability method (the method used by a utility to identify the district and feeders with the poorest reliability), major event time periods, operation districts and feeders with the poorest reliability, and evaluations of remedial actions. All the detailed requirements are included in the referenced document (COMAR 2010).

The June 2012 derecho caused widespread destruction, including significant system-wide damage across the BGE service territory. The utility reported general information about the storm, such as wind speeds, as well as physical damage to its transmission and distribution facilities. Information about interruption statistics and hourly updates on restoration work were included as well. According to BGE, the company received 14,000 calls about downed transmission and distribution lines, involving 9,200 transmission and distribution line-related jobs; 4,988 line sections were replaced. A number of other infrastructure components were also replaced, including 7,494 fuses, 380 poles, and 375 distribution transformers (BGE 2012a). More than 760,000 interruptions were recorded, with some customers experiencing multiple power outages because of the complexity of the simultaneous heat wave and derecho.

BGE reported that approximately 5,600 staff or subcontractors were engaged in restoration, including 2,800 overhead line/tree workers; 1,500 damage assessment/public safety personnel; and 1,250 call center, warehouse, staging area, and support personnel. Outside assistance also played an important role in the recovery and restoration work. BGE reported that more than 1,500 out-of-state utility workers from 18 states and three Canadian provinces participated in the restoration effort. In addition, 165 company or contractor personnel from the Philadelphia Electricity Company, a sister utility of BGE under Exelon, also took part in restoration activities.

Cost recovery

According to the Grid Resiliency Task Force's report, a utility is generally permitted to recover its revenue requirements through rates under traditional ratemaking principles (Grid Resiliency Task Force 2012). A utility is required to provide information on "prudently-incurred operating expenses, plus a reasonable allowed rate of return on any capital investments of the utility (known in the industry as the utility's 'rate base')." The rate change process starts with the utility filing an application seeking a rate increase/decrease, along with detailed information establishing the reasoning behind the request. The MDPSC comprehensively examines the rate request while it suspends the rates proposed by the utility for a period of 180 days.

Although we cannot locate, either on the BGE website or in reports submitted by BGE to the MDPSC, any official reports of the direct economic cost to BGE of the June derecho, we find the following statement in BGE's parent company Exelon's 2012 annual report: "BGE incurred $62 million of incremental costs during the year ended December 31, 2012, of which $20 million are capital costs" (Exelon 2013). NOAA's National Centers for Environmental Information (NCEI) state, in their 2019 report on billion-dollar weather/climate disasters in the U.S., that the total economic cost of the June derecho in all affected states was approximately $2.9 billion (NCEI 2019). However, we were unable to locate any breakdown of this total cost estimate into specific industries, affected utilities, or impact categories.

It is worth noting that BGE applied to MDPSC on July 27, 2012 to adjust its electricity and gas base rates (Case No. 9299). In this application, BGE provided supportive evidence for a $130.5 million increase in its electric distribution revenue requirement (MDPSC 2013a). Although there are no formal written notes linking this rate change case with the June derecho, BGE provided its annual major storm damage expenses for electrical service, which included such costs from 1999 to 2011, in supplementary materials. It is possible that the costs BGE incurred as a result of the June derecho could factor into future BGE rate change cases. A supplemental document BGE submitted with a request to adjust base rates in 2019 (Case No. 9610) included annual major storm damage expenses from 2018 onwards (BGE 2019a).

Categories of expenses: In its damage report, BGE inventoried physical infrastructure (poles, distribution transformers, fuses, wires) replacements along with the number of overhead crews from BGE's own staff and outside assistance that participated in the storm recovery and restoration. During the restoration effort, costs were incurred to maintain a staging area for restoration workers. The costs included both lodging (e.g., hotels, meals, caterers) and rentals (e.g., cars, vans, equipment, security, tents, global positioning system units) (BGE 2012a, 2012b).

Accounting procedures: Exelon's 2012 annual report lists "storm cost deferral" and "storm-related costs" as part of operating and maintenance expenses. The procedure follows the company's internal accounting system. In the report, the company mentions that its preparation of financial statements conformed with generally accepted accounting principles, but no specific accounting procedures for storm-related costs are mentioned (Exelon 2013).

Methods and techniques to estimate costs to utilities: Notwithstanding the information about the physical damage caused by the derecho and the number of personnel deployed for restoration work, BGE's report does not mention any specific methods for estimating the relevant costs.

Quality, accuracy, and reliability of estimates: The total cost incurred by BGE as a result of the June derecho is reported by Exelon in its 2012 annual report (Exelon 2013). This estimate of the total cost is not accompanied by a breakdown of estimates of costs incurred in specific categories. Despite the lack of a cost breakdown, BGE provided detailed numbers for all types of vehicles in use and personnel involved in the restoration work, as well as the numbers of damaged electricity system components that the utility replaced.

Availability of documentation: Exelon's 2012 annual report that contains information on the total cost of the June derecho for its subsidiary BGE (Exelon 2013) can be found on its website. BGE's detailed information about the derecho, the physical damage it caused, and the utility's restoration effort can be found on the MDPSC website, under Case 9298. Relevant documents include a major outage event report (BGE 2012b) and a presentation describing the utility's response to the derecho (BGE 2012a).

Table 8-2. Availability of economic information related to cost recovery

Utility	Precipitating Event	Trans. System Costs	Dist. System Costs	Gen. System Costs	Increased Customer Service Costs	Other Costs	Comments
Baltimore Gas & Electric	June 2012 Derecho	●	●	○	○	○	

Outcome of cost recovery request

On February 22, 2013, the MDPSC issued an order that partially granted BGE's application to adjust its electricity and gas base rates. The application had been filed by BGE on July 27, 2012, requesting increases of approximately $130 million in electricity distribution rates and approximately $45 million in gas distribution rates. The MDPSC authorized an increase in base rate revenues for electricity distribution service of $80,554,000. Neither BGE's request for a single, combined return on equity for its electricity and gas operations, nor its recommended return on equity for electricity or gas operations that can enhance the return to the shareholders was approved (MDPSC 2013b). The MDPSC did not require BGE to file formal plans for its electricity and gas systems at the time of approval but directed the parties (staff at MDPSC and BGE) to "meet, develop and submit a reporting requirement for gas and electric infrastructure replacement for the Commission's consideration."

8.3 Preparing for the future

Upgrading system infrastructure, maintenance, and readiness standards

Based on BGE's damage description, which was also reported to the MDPSC, the utility replaced 4,988 sections of line, 7,494 fuses, 380 poles, and 375 distribution transformers during the derecho recovery and restoration process, (BGE 2012a*). However, we cannot locate documents that can indicate whether the utility immediately replaced the damaged elements mentioned above with similar elements or whether it replaced infrastructure based on a higher design standard.*

As part of a five-year plan known as the Electric Reliability Investment (ERI) initiative, BGE submits an Annual ERI Initiative Report. In these reports, along with detailed information on performance measurements for various programs (such as a diverse routing program and a selective undergrounding program), BGE also provides actual capital and O&M expenditures and includes cost estimates for the programs it plans to implement during the following year (BGE 2014, 2015, 2016, 2017, 2018).

Economic benefits—*avoided customer interruption costs*

The Grid Resiliency Task Force's report pointed out that residential customers incur a variety of costs as a result of power outages. The most direct costs include expenses for restaurant meals and hotel stays. For residential customers who depend on electric pumps for well water, direct costs are incurred to pay for alternative water sources. Moreover, the inconvenience caused by a power outage can be substantial because of impacts such as interruptions in internet access and telephone service. The cost of power outages exacerbating health-related conditions can be very high. The report does not estimate these costs because methods are lacking, and the mechanisms for these costs differ considerably from one another. One additional cost that the report mentions is for households with portable electric generators. The cost of the fuel to operate emergency-use generators can be more than $0.75/kWh, and these portable generators can typically only supply a fraction of the essential electricity demand of a household (Grid Resiliency Task Force 2012).

Using the methods discussed below, the Task Force estimated that the power outages that resulted from the June derecho cost BGE residential customers roughly $321 million because of lost load. BGE's share was more than half of the total estimated cost of approximately $594 million to residential customers of all Maryland utilities.

Beyond the estimates for the June derecho, the Task Force also calculated analogous cost estimates for two previous storms: "Snowmaggedon" and Hurricane Irene.[44] Combining all three storm events, the Task Force calculated the cumulative outage hours (i.e., the total customer interruptions) and costs per customer, which can be interpreted as the expected cost for a randomly selected Maryland customer who experienced power interruptions resulting from these three events. The total cost of load lost as a result of all three storms was $519 per average customer in the BGE territory, compared to $455 in Maryland as a whole.

Methods and techniques to estimate costs to customers: The Grid Resiliency Task Force's report applied Berkeley Lab's method of estimating value of reliability or lost load (Sullivan et al. 2009). The Berkeley Lab study estimated "customer damage functions" for three types of customers: medium and large C&I (commercial and industrial), small C&I, and residential. A residential customer incurs a cost of $4.08 on average for a one-hour service interruption on a summer weekday and $11.20 per hour for outages with eight-hour durations during the same period. The costs for small C&I customers are $856 and $4,991, respectively, and for medium and large C&I customers $21,312 and $98,278, respectively. More information about these estimates can be found in the original Berkeley Lab study (Sullivan et al. 2009).

The Grid Resiliency Task Force, based on standardized MDPSC storm reports, extracted figures on the peak or total customer interruptions and total number of outage hours for each utility. By applying residential VOLL estimates from the Berkeley Lab study to the total outage hours affecting residential customers of each Maryland electric utility, the Task Force calculated the total potential cost of storm outages for residential customers. As mentioned above, the final cost estimates were $321 million for BGE residential customers, and $594 million for residential customers of all Maryland utilities combined.

When it comes to the impacts of BGE's prospective actions to enhance its system reliability, our analysis is primarily based on two initiatives: the five-year short-term reliability improvement plan and the long-

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[44] Irene was the subject of a dedicated Case, No. 9279. Subsequently, the MDPSC investigated Tropical Storm Sandy in 2012 (Case No. 9308), and Winter Storm Riley in 2018 (Case No. 9485).

term assessment. In these contexts, the avoided electricity system damages due to potential future extreme weather events are mentioned as benefits of actions to improve reliability.

BGE proposed its five-year plan to enhance its system reliability in response to the MDPSC's order in the derecho case. This plan was set forth in BGE's base rate application case filed on May 17, 2013. BGE's ERI proposed eight programs that "can provide immediate benefits, improve reliability for known issues currently impacting customers, and deliver a high level of benefits relative to the cost of the program (BGE 2013a)." BGE compared the capital and O&M costs for each program in each year (from 2014 to 2018) with the program's expected benefits in terms of SAIFI and SAIDI. The contributions of each program to improved SAIFI and SAIDI were presented as percentages. For example, the Expansion of the Poorest Performing Feeder Program was estimated to account for 16% of the overall expected 2018 SAIFI benefit. BGE also compared investment costs with the reliability benefits of the eight programs gauged in terms of avoided customer interruptions (ACI) and avoided customer minutes of interruption (ACMI). BGE called both of these comparisons CBAs, but this is a non-standard use of the terminology because the benefits were not expressed in monetary terms. These are more accurately termed CEAs. MDSPC approved five of these programs (Case No. 9326).

The comprehensive long-term assessment included in BGE's submission to the MDPSC was prepared by WorleyParsons, a provider of professional services to the resources and energy sectors and complex process industries (BGE 2013b). The report reviews technologies and hardening solutions, such as targeted undergrounding, enhanced tree trimming, and preventative tree removal. The cost-effectiveness of each program is analyzed so that the utility can prioritize the deployment of these technologies. Similar to the studies mentioned above, these were called CBAs of the ERI Initiative programs, but the benefits were presented in terms of ACI and ACMI, rather than in monetary terms. The consultant studied the investments necessary to prevent a power interruption, or restore service within a specified time limit, for storms of certain magnitudes, and defined the least-cost options as "cost-efficient." Although the costs of these enhancement programs vary significantly from "multibillion-dollar capital enhancements on undergrounding to several million-dollar O&M on lightning protection improvements," the analysis revealed that four programs would be cost-effective and applicable to BGE's system while four other programs would be relatively inefficient. BGE also estimated the resources necessary for restoring power to at least 95% of its customers within 24, 48, 72, or 96 hours if there were 400,000, 500,000, or 600,000 customers experiencing power interruptions. The utility presented tables showing the primary overhead line personnel needed and estimated costs for mutual assistance for all the scenarios mentioned above. BGE also included the estimated rate impacts of the restoration costs on residential, small C&I, and medium and large C&I customers.

More recently, however, BGE has used the ICE Calculator for valuation of benefits of investments made as part of the ERI initiative. In its 2019 rate case, the utility applied the tool to estimate the benefits of expanded recloser deployment.[45] Specifically, it calculated the avoided costs resulting from the

[45] A recloser is essentially a circuit breaker, used in overhead distribution lines.

improvements in reliability, measured in terms of reduced SAIFI and SAIDI, and found that the avoided costs exceeded the costs of deployment by more than an order of magnitude (BGE 2019b).

MDPSC staff also used the ICE Calculator in that rate case to conduct its own valuation of BGE's proposed recloser deployment under different assumptions and found that the deployment's benefits estimates were lower than BGE's valuation, but they still substantially exceeded the costs of the measures (MDPSC 2019c)

Quality, accuracy, and reliability of estimates: The Grid Resiliency Task Force's analysis relied on some simplifying assumptions that enabled the Task Force to estimate the cost of lost load suffered by BGE residential customers as a result of the derecho. BGE's cost-effectiveness comparison, carried out to prioritize eight potential reliability enhancement programs, provided a breakdown of the relative contributions of each program to several major reliability metrics. The CEAs for both short-term reliability programs and long-term technology-hardening solutions contain cost and effectiveness details for each program in tabular form. Both reports include comparisons among programs, interpretations of the CEA, and recommendations for hardening plans (BGE 2013a, 2013b).

Availability of documentation: The Grid Resiliency Task Force's report on the June derecho, BGE's short-term reliability improvement plan, and its long-term assessment can all be found on the MDPSC website, under a docket search for Case 9298 (Grid Resiliency Task Force 2012, BGE 2013a, BGE 2013b).

Economic benefits—*avoided regional economic impacts*

Although numerous documents record the physical and direct economic impacts of the June derecho, we could not find utility or regulatory documents reporting the broader economic impacts (such as loss of employment and/or the impact on the gross state product) that could be avoided through the short-term reliability improvement plan or long-term assessment. We located a total estimated cost of the derecho in a recent NCEI report, which claimed that the total cost in all affected states was $2.9 billion (NCEI 2019). However, NCEI did not break this total cost down into different categories or industries (such as electricity). Along with this cost estimate, the data also indicated a consumer-price-index-adjusted cost estimate of $3.3 billion for the June derecho. The exact method NCEI used to calculate these figures was not specified.

Methods and techniques to estimate regional economy-wide impacts: N/A

Quality, accuracy, and reliability of estimates: N/A

Availability of documentation: N/A

Economic benefits—*other avoided societal impacts*

We found no information in the public record detailing other avoided societal impacts.

Methods and techniques to estimate other avoided societal impacts: N/A

Quality, accuracy, and reliability of estimates: N/A

Availability of documentation: N/A

Table 8-3. Availability of economic information associated with future event preparedness

Organization	Precipitating Event	Avoided Customer Interruption Costs	Avoided Regional Economic Impacts	Other Avoided Societal Impacts	Other	Cost-Effectiveness Analysis?	Cost-Benefit Analysis?	Comments
Other	2012 Derecho	●	○	○	○	**Yes**	**Yes**	

8.4 Discussion

Process and institutional aspects of preparedness and recovery planning

Maryland is closely akin to New York in that resilience is the central framing principle for its storm-hardening initiative. But Maryland's case also parallels New York's in that, in practical details, resilience investments and measures were in most cases enlargements and/or enhancements of types of storm-hardening measures that were already known.

Multiple stakeholders across the state of Maryland actively participated in post-derecho regulatory proceedings. After the case was initiated, utilities filed major outage reports, short-term reliability enhancement plans, and long-term comprehensive assessment reports, as required. In addition to the MDPSC and the utilities, the Office of People's Counsel, MEA, and local authorities (such as Montgomery County MD) also participated in the process. Utilities revised their reports based on comments from commission staff and relevant local municipal entities; in addition, utilities commented on, and responded to, the Grid Resiliency Task Force's report.

After the Grid Resiliency Task Force submitted its report on the derecho and made a list of specific technology, infrastructure, regulatory, and process recommendations, the MEA monitored the actions of responsible parties to ensure the implementation of these recommendations. The process involved multiple stakeholders including the MEA, MDPSC, utilities, Maryland Emergency, University of Maryland Center for Health & Homeland Security, and the Energy Future Coalition.

How the findings relate to previous work

The June 2012 derecho was one of the most destructive storms in the 200+ year history of BGE and caused widespread damage and power outages across Maryland (BGE 2013b). Derecho events of this magnitude are relatively infrequent, but this case study provides insight into how regulatory bodies, utilities, and other government agencies can use the occasion of an extreme weather event as an opportunity to thoroughly review storm impacts (retrospective) and propose short-term reliability and long-term hardening initiatives (prospective).

The assessments involving the MDPSC, utilities, and other stakeholders were comprehensive and publicly available. Unlike the public utility commissions in the Texas and New Hampshire cases, the MDPSC explicitly required utilities to conduct a CEA of each measure included in the reliability improvement plans. MDPSC Case 9298, which is solely dedicated to the June derecho event, provided all the records of the proceedings and tracked multiple stakeholders' participation and involvement in the storm evaluation process.

Furthermore, the Maryland derecho case demonstrates that active government engagement in resilience efforts (in this case several agencies participated in addition to MDPSC) led to improvements. Executive Order 01.01.2012.15 directed the Grid Resiliency Task Force to evaluate the June derecho event and solicit experts' recommendations for improving the Maryland electricity distribution system. The Task Force made a total of 11 recommendations, which span issues from improvements in regulations (such as “Improve RM43’s reliability and reporting requirements”) to cost recovery mechanism design (“Allow a tracker cost recovery mechanism for accelerated and incremental investments”), ratemaking changes (“Implement a ratemaking structure that aligns customer and utility incentives”), resiliency metrics (“Determine cost-effective level of investment in resiliency”), and other regulatory changes (Grid Resiliency Task Force 2012). The report laid a foundation for the regulatory body and utilities to encourage and engage in future resilience improvements.

It is crucial to monitor how the recommendations made by the Task Force are implemented. Grid Resiliency Task Force information on MEA’s website includes the recommendations, the parties involved, and the actions undertaken to address the recommendation. For example, following the recommendation to “increase citizen participation in list of special needs customers and share information with emergency management agencies,” BGE filed with the MDPSC, prior to storm Sandy on October 26, 2012, a request to disclose to government officials’ data on special needs customers and outage information. This request was approved by the MDPSC on October 30, 2012, allowing information-sharing between Maryland’s major utilities and state emergency officials. In addition to what is listed on the website, the MDPSC, on March 27, 2014, opened a case addressing the review of annual performance reports on electricity service reliability (Case No. 9353). After RM 43 was enacted, the MDPSC held a second rulemaking session on September 1-2, 2015. This rulemaking session proposed more stringent system-wide reliability standards for utilities that provide electricity service, from 2016 to 2019. Order 89260, which is included in case 9353, laid out discussions about system-wide reliability standards, poorest-performing feeder standards, additional reliability indices and other related matters, which was consistent with what the Task Force recommended (MDPSC 2018, 2019b). The MDPSC has also been working on advancing an alternative utility rate-setting process – a multi-year plan. This new ratemaking plan can include performance-based measures, as the fourth recommendation by the Task Force suggested (MDPSC 2019a).

Additional commentary on economic data and methods

BGE has provided detailed information on damage to its electricity system and on resources utilized (infrastructure replacements and personnel deployment) during storm recovery and restoration. However, with only an overall estimate of the costs incurred by the utility as a result of the June derecho, it is not possible to break down the costs and attribute them to specific parts of the physical electricity system or a specific category of expenses. In terms of prospective efforts to enhance resilience, both BGE’s short-term (ERI initiative) and long-term assessments use the ACI and ACMI metrics to quantify potential improvements stemming from alternative programs.

As discussed earlier, the Grid Resiliency Task Force’s report estimates the cost of the derecho power outages to residential customers. The report calculates this cost by applying VOLL estimates from a Berkeley Lab study to outage information provided by Maryland utilities, including BGE. The task force does not compute broad social costs but mentions a number of costs associated with the power interruptions that can be viewed as social costs: inconvenience because of a lack of internet access or telephone service, potential delays related to transportation, and health-related impacts affecting the elderly in particular. We could not identify any records estimating or even acknowledging costs to sectors of the Maryland economy other than electricity that would affect gross state product.

The Task Force report briefly discusses how climate change would affect the electricity distribution system, and the utility's reports mention climate change. However, no methods or models were put forth that could be used to project the effects of climate change on reliability metrics or on the prioritization of different resilience improvement programs. A promising start might be to project the frequency and severity of future disasters based on historic storms and weather records and incorporate these predictions into CBA.

9. Discussion of key findings and recommendations for future research

9.1 How do utilities assess damage and restoration costs caused by extreme weather?

Utilities assess the physical impacts of extreme weather events and the details of response and recovery operations, which form the basis of their petitions to regulators to recoup associated costs. These petitions are based on standard cost accounting categories such as materials, labor, and other (e.g., providing emergency services to customers).

The utilities we studied use a generally similar approach to documenting and reporting physical damage from, and engineering impacts of, severe weather although there are differences in the cost categories that are reported for response and recovery from power interruptions. For purposes of comparison, we aggregated these cost-recovery categories into coarsely defined groups of requests related to: distribution, transmission, and generation systems; customer service; and a catch-all "other" category (see Table 9-1). Utilities' physical and engineering assessments can be extremely detailed, as illustrated by the Florida and New York case studies in this report. The thoroughness required of utilities varies, as does the rigor of scrutiny applied to applications for recovery, through rates or other mechanisms, of extreme-weather-related costs.

Table 9-1. Availability of economic information associated with cost recovery

Case Study	Precipitating Event(s)	Transmission System Costs	Distribution System Costs	Generation System Costs	Increased Customer Service Costs	Other Costs
Florida	Hurricanes of 2004 and 2005	●	●	●	●	●
New York	Tropical Storm Sandy	●	●	●	●	●
Texas	Hurricanes of 2005, 2008, and 2017	●	●	N/A	◒	●
California	2007 Southern California wildfires	○	○	○	○	○
New Hampshire	Severe fall and winter storms	N/A	●	N/A	○	○
Maryland	2012 derecho	●	●	○	○	○

9.2 How do utilities estimate customer costs of past power interruptions?

Following power interruptions caused by extreme events, utilities report statistics including numbers and locations of customers without power and the duration of outages, but, with one exception among the case studies in this report, there were no attempts to monetize these impacts.

Only Maryland retroactively estimated the customer economic costs of an extreme event, the June 2012 derecho. However, this analysis was conducted not by the utility or the regulator, but by a state task force appointed by the governor.

9.3 How do utilities or others estimate the costs and benefits of investments to reduce system vulnerabilities to future extreme weather?

Utility and customer costs and benefits: As a rule, the costs of preventive investments can be estimated with reasonable accuracy, but the economic benefits are very uncertain. Most of the utilities' and regulators' economic assessments of these investments are based on cost-effectiveness techniques, which have traditionally been used in reliability analysis. In several cases utilities or regulators used additional techniques and information. Con Ed applied avoided customer interruption cost data from Berkeley Lab's ICE Calculator to value potential investments in a variation on cost-benefit analysis. Both BGE and Maryland regulators used these data to value benefits from reliability measures in a calculation supporting CEA. SDG&E recently used ICE Calculator information in its risk-based economic evaluation of wildfire safety investments. However, the ICE Calculator is based on economic surveys of short-term interruptions (up to 16 hours). There are currently no sources of ACI cost data that are applicable to interruptions of several days or weeks (or longer); therefore, it is difficult to gauge the accuracy of utilities' estimates of the benefits to customers from investments to prevent interruptions of these (or longer) durations. Furthermore, there is little or no evidence that other avoided societal impacts are being formally included in CBAs or as a supplement to CEA. Table 9-2 shows the availability of economic information associated with event preparedness.

Regional economic analysis: No utility or regulatory body analyzed regional economic impacts of an actual or avoided power interruption; one municipal government (encompassing the utility service territory) did so. Because such analyses would also provide economy-wide estimates of the benefits of preventing future interruptions, it is likely that these types of benefits are significantly undervalued in the current regulatory process.

Table 9-2. Availability of economic information associated with event preparedness

Case Study	Precipitating Event(s)	Avoided Customer Interruption Costs	Avoided Regional Economic Impacts	Other Avoided Societal Impacts	Other	Cost-Effectiveness Analysis?	Cost-Benefit Analysis?
Florida	Hurricanes of 2004 and 2005	○	○	○	○	**Yes**	**No**
New York	Tropical Storm Sandy	●	◒	○	○	**Yes**	**Yes**
Texas	Hurricanes of 2005, 2008, and 2017	○	○	○	○	**Yes**	**Yes**
California	2007 Southern California wildfires	◒	○	○	○	**Yes**	**No**
New Hampshire	Severe fall and winter storms	○	○	○	○	**Yes**	**No**
Maryland	2012 derecho	●	○	○	○	**Yes**	**Yes**

FPL performs cost-effectiveness analysis to assess potential storm-hardening investments and measures, the engineering details of which are determined by the utility with input from regulators and other stakeholders in regulatory reviews. This is in keeping with FPL's established practice for reliability investments. FPL has claimed significant benefits to customers from these investments but does not quantify or monetize these benefits, citing the lack of valuation information that would allow it to do so. The FPSC has approved this approach.

Con Ed – in collaboration with a broad collection of stakeholders – has developed a method for storm-hardening investment valuation based in part on short-term avoided cost estimates from the ICE Calculator, but the method extrapolates from 16-hour interruptions to 12-day interruptions. The method incorporates cost-effectiveness and is a variation of CBA. The marginal costs and benefits of potential investments and measures are compared but within a framework that incorporates engineering constraints and risk factors.

CenterPoint Energy (Texas) reported use of CEA in the utility's storm-hardening documents, but no details were included. A study carried out by CenterPoint Energy in collaboration with EPRI employed ICE Calculator data in a CBA of the utility's smart grid project designed to improve reliability of electricity service to critical infrastructure and key business districts. However, the study did not address or evaluate the types of larger preventive investments that have been discussed throughout this report.

SDG&E has participated in a multi-year, multi-initiative analytical effort overseen by the CPUC to develop improved methods for reducing the vulnerability of the state's electricity distribution system to wildfires. These methods are currently being implemented. The regulator has found that it is not currently possible to monetize the benefits of particular investments that reduce wildfire risk but that the overall qualitative social benefits of such investments are extremely high and justify the increased expenditures that are being made for this purpose.

Unitil Energy Systems in New Hampshire regularly conducts CEA of its reliability enhancement programs. Effectiveness is measured in terms of projected improvements in reliability metrics. Because these improvements are not monetized, these studies cannot be considered examples of CBA.

Although the BGE consultant report on resilience planning discusses CBA, the actual technique used was a form of CEA. The governor's Grid Resiliency Task Force recommended that, going forward, avoided costs of power interruptions be estimated for different Maryland electricity customer classes and the results be used by utilities on a routine basis to value investments in reliability and resiliency. This follow-up study has apparently not been carried out, but public service commission staff are using the ICE Calculator to value the benefits of proposed reliability-resilience investments as a supplement to cost-effectiveness analysis.

In summary, cost-effectiveness analysis is the primary technique used by the utilities we studied to assess potential storm-hardening and other investments aimed at preventing power interruptions of both shorter and longer durations. In several cases, avoided cost information was also used to monetize the benefits of these investments although not in "formal" CBA, in which decisions are made solely on the basis of comparing marginal costs with marginal benefits. Utilities that use avoided costs are relying upon costs generated by the ICE Calculator, which, as previously noted, are intended to apply to only short-duration interruptions.

The lack of avoided cost data for power interruptions lasting one day to several weeks is particularly salient. Put simply, there are currently no such data readily available for incorporation into regulatory and utility decision making. This fact was cited in Florida, New York, and Maryland although the three states' responses to this problem were different. In addition, state laws and regulations typically stipulate the use of CEA; when laws or regulations also refer to CBA, the intent is not necessarily to require monetization of benefits. For example, BGE estimates benefits using the units of common reliability metrics such as ACMI, stopping short of valuing these improvements monetarily. Moreover, different regulatory commissions, state energy and environmental authorities, and other stakeholders engage with methodological matters to different degrees; in both New York and Maryland the use of CBA arose in part from multi-stakeholder initiatives although these have not resulted in new empirical studies of jurisdiction-specific avoided costs. The absence of data and of specific regulatory guidance appears to be a key reason that utilities have been using or adapting their existing, cost-effectiveness-based, reliability economic assessment methods to analyze larger-than-previous investments in storm hardening.

We found that utilities and regulators performed almost no estimation or modeling of utility-service-territory-wide or regional economic impacts. An exception was the New York City government's study of potential impacts of future super storms on the city's economic output; the city's geographic footprint closely coincides with Con Ed's service territory. Strictly speaking, we cannot say that this type of analysis is "missing" in this context because, historically and currently, it is not referred to, much less required, in state laws on electric power utilities or in regulatory codes. However, existing computational economic modeling studies of LDWIs caused by other (than extreme weather) types of events suggest that the local economy-wide impacts of "dark sky" as well as "black sky" disruptions could be considerable. It follows that that the benefits of more significant storm-hardening and other investments could be considerably larger than is currently recognized. Thus, all else being equal, there is a clear rationale for modeling of this type and for determining ways to incorporate this information into existing decision-making processes.

We noted at several points in the text that there have been numerous model-based and other studies of storm or hurricane impacts on state and regional economies. But there are almost no examples of such studies specifically isolating the economic impacts of the resulting power interruptions. An exception is the modeling study of tropical storm Sandy's economic impacts on the entire U.S. East Coast that we cited in the introduction, which includes such an estimate. This study estimates power-loss effects on the regional economy but does not disaggregate this estimate by sub-regions or states.

This example highlights a dilemma: the economies of large regions of the country that might be affected by severe-weather-caused power interruptions are not under the purview of individual utilities, regulators, or even states. On the one hand, this indicates the potential value of studying regional economic impacts with sufficient disaggregation to identify impacts at the utility service territory level. But on the other hand, it also suggests a need and an opportunity for inter-scale economic analysis of major power disruptions by utility regulators and state and regional officials. *In short, future investments in power systems have both direct and indirect benefits that extend well beyond the jurisdiction tasked with reviewing and approving (or disallowing) those investments.*

Avoiding other economic impacts: We found no examples of utilities or regulators estimating other types of avoided economic impacts to inform the decision-making process. Other economic impacts include, but are not limited to, the value of improved public safety and private property.

9.4 How do utilities and regulators use the concept of resilience in economic assessments of extreme weather impacts?

The term "resilience" was used extensively by utilities and regulators in two of the six cases we studied, less extensively in two, and very little in the remaining two. The usage was primarily semantic in the sense that the "resilience investments" mentioned were for the most part types of storm-hardening and similar measures with which utilities and regulators have considerable experience. What has changed from historical norms is that the frequency and magnitude of precipitating extreme events and the severity of their power system consequences have increased; therefore, the scale and cost of investments to address these risks have also increased. We find that it's generally not at issue which "metrics" should be used in this context. Rather, the challenge is how to economically value investments developed using these metrics. For these reasons, efforts to identify and address "resilience" as a categorically distinct substantive phenomenon may not align well with utility and regulatory practices and perspectives and may be counterproductive.

Florida

Although the term "resilience" appears occasionally in utility and regulatory documents, resilience *per se* is not formally recognized or used by the utility or the regulator, either as a concept or as an operational criterion, in Florida's storm-hardening planning or storm impact analysis and recovery. Florida does not single out "resilience investments" as a special category, and the metrics needed for analysis are well-known specific physical and/or engineering quantities pertaining to electricity infrastructure; that is, there are no special "resilience metrics."

New York

Resilience terminology has been used in virtually all of Con Ed's and NYPSC's efforts and initiatives on preparing for and recovering from extreme weather events. However, the investments and measures proposed and undertaken under this rubric are typically more extensive, advanced, and in many cases expensive, storm-hardening actions of types already known, rather than categorically different types. As in Florida, the appropriate resilience "metrics" appear to be well-known; an example in the New York case is the size of the flood plain. The record indicates that in this and other examples there was debate not over appropriate metrics, but rather about the appropriate level of risk tolerance for the utility and the value of reducing risk.

Texas

Both AEP Texas and CenterPoint Energy use the term "resilience" but not as extensively as FPL or Con Ed. Moreover, the Texas utilities do not formally define this term. The regulators (PUCT and ERCOT) use FERC's definition: "the ability to withstand or recover from some disturbance." The sole mention of resilience in Texas laws on electricity service refers specifically to storm hardening.

California

Resilience was neither a conceptual nor a practical part of the SDG&E's or CPUC's wildfire risk management planning.

New Hampshire

In New Hampshire, resilience was referred to only minimally in regulatory and utility documents.

Maryland

Similar to the New York case study, in Maryland resilience is the overarching rubric for extensive efforts – by state government as well as the utility and utilities commission – to reduce the state power system's vulnerability to high winds, severe storms, and other threats. As in the case of Con Ed and New York, however, the details of the record show that the authorities do not recognize a sharp distinction between reliability and resilience, other than a five-minute threshold for the duration of interruptions. Most of the recommended measures refer jointly to reliability and resiliency. Overall, the theme of this case is that the threats to the system have increased, and the scale and cost of measures to address them have also increased.

Resilience refers to two "properties" of the electric power system, encompassing both its physical infrastructure and its strategic and operational management: (1) the system's capacity to withstand the impacts of such events as hurricanes, snowstorms, fires, etc. and keep functioning with little or no interruption; and (2) its capacity to expeditiously recover from power interruptions when they do occur. The case studies highlight the fact that, particularly in parts of the country where severe weather and other threats are in some sense routine, the importance of both of these has long been recognized, and utilities and regulators have ample experience in addressing them (e.g., Finkler et al. 2016).

The case studies reveal that what are often referred to (primarily by those outside utilities and regulatory commissions) as "resilience investments" are in fact measures to address these types of *existing* risks and vulnerabilities with which utilities and regulators generally have considerable experience, and which they have been undertaking for decades. What distinguishes the examples discussed in the case studies is that the *magnitudes* of precipitating extreme events, and the severity of their power system consequences, have increased. Thus, the scale of investments and measures to address such risks has also increased and will continue to do so. But, in general, there are not new and categorically different *types* of investments and measures required. Storm hardening has considerably expanded, and its costs have accordingly increased, but with some exceptions, the key measures – vegetation management, pole replacement, etc. – are essentially the same.

These considerations are in contrast to much policy and technical discussion of resilience being fundamentally different from reliability. We have noted in several of the case studies that "resilience" is referred to little if at all in most utility and regulatory documentation. This disjunction between much technical and policy discussion of resilience on the one hand, and the actual problems being addressed by utilities and regulators on the other, is illustrated by comparing the findings of the Florida and New York case studies. Both have, especially since the turn of the century, been experiencing unprecedented impacts of hurricanes and storms on their electric power systems, and both expect that this trend will continue. Both have undertaken extensive multi-stakeholder and multi-year efforts to improve their utilities' preparedness for these threats, in their physical infrastructure, operations, and financial planning. Both states' efforts are broadly focused on storm hardening and emergency response to and recovery from storms. However, as we noted, in Florida there is very limited mention of "resilience" in 15 years of utility planning documents and the regulatory record, while in New York the "resilience" rubric is used very extensively. It does not play a notable role in the Texas or New Hampshire documents that we reviewed and plays essentially no role in the California case study. Maryland is similar to New York in that the resilience rubric is central in the state's efforts to improve storm hardening, but the details show that the actual measures and investments proposed or undertaken are evidence of the degree to which, in practice, "resilience" is a semantic rather than substantive issue.

An important and related point has to do with resilience “metrics,” which have been the focus of a considerable amount of attention and work for several years. We did not find that an absence of appropriate physical or engineering metrics was an issue for utilities and regulators confronting the challenge of reducing their systems’ increasing vulnerability to extreme weather. On the contrary, the specific physical and engineering quantities on which investments and actions must be focused are generally already understood by utilities and by many regulatory personnel and other stakeholders. What is lacking are metrics that can be used to estimate the potential economic *benefits* of capital investments and operational strategies that reduce vulnerability.

This point highlights an important, but generally overlooked distinction between metrics and *thresholds*. Metrics are scales, indices, or similar ways of measuring or ranking particular quantities or variables. By contrast, thresholds are targets, goals, or criteria that can be defined in terms of particular values of metrics. Informally, metrics represent what quantities are being affected, while, in the current context, thresholds identify how much these quantities *should* be (or are) affected. For example, the number of customers affected and the duration of a power interruption are metrics, but to apply them to assessing preventive investments, thresholds are needed to decide, for example, a maximum number of customers who will be affected, or maximum duration of interruptions, that should be the goals for planning. Economic valuations such as avoided costs provide such thresholds. This fact is generally not recognized in much of the published work related to resilience.

9.5 How do regulatory processes influence utilities’ economic analysis related to power interruptions?

Institutional factors including laws, regulations, and regulatory practices can have a very significant influence on utilities’ preparation for, and response to, LDWIs. Utilities’ petitions for cost recovery after responding to major disruptive events and their proposals for preventive investments are usually assessed in regulatory proceedings that are adversarial by design, to encompass the often-competing perspectives and interests of multiple stakeholders. The economic techniques used for analyzing preventive investments may reflect both regulatory requirements and established practices within the utilities. Moreover, technical improvements in economic methods that utilities use for investment valuation may be outcomes of, not inputs to, regulatory proceedings or technical studies performed under the auspices of regulators.

All utility requests for cost recovery following major disruptions, and all of their proposals for investments in improving system reliability or resiliency (or for essentially any other purpose) must be submitted to regulators for scrutiny and approval. We have noted the importance of laws and regulations requiring cost-effectiveness, and in some cases CBA, of storm-hardening investments. However, the details of regulatory processes are arguably even more important in some cases. The technical work that is involved in developing storm-hardening and other proposals that are presented to commissioners can involve multiple stakeholders – not just utilities and regulatory staff but also non-profit organizations, other government entities, and academic institutions. Moreover, as noted above, these processes are adversarial; utility proposals are routinely opposed, and settlements are negotiated between stakeholders. In some cases of storm-hardening planning, methods are determined and agreed upon in these collective deliberations. In such cases, technical extensions, enhancements, or improvements to information and methods are often *outcomes of*, not *inputs to*, to these processes. That is, regardless of their technical merits, new methods and other information must be credible to, and agreed upon by, a consensus of multiple stakeholders. One implication is that caution should be exercised regarding expectations about adoption by utilities, regulators, and stakeholders, of analytical methods, techniques, and other information, developed outside the local "decision ecosystems" that comprise utilities, regulators, other stakeholders, and laws, regulations, and customs. As we have discussed, models are being used to estimate regional economic impacts from power interruptions, but these models were developed by academia and have not been generally incorporated into traditional regulator-utility decision-making processes.

The continued reliance on CEA discussed above also reflects an important institutional consideration. It highlights the fact that, even in the absence of long-duration interruptions, not all utilities have adopted the practice of economic valuation of reliability improvements aimed at preventing even momentary or short-duration power outages. Utilities that have not done so, and their regulators, may lack familiarity and an established technical and procedural basis upon which to build in order to analyze the economic value larger investments related to preventing LWDIs. This suggests that it may be useful for utilities to develop economic valuation capabilities relevant to both short- and longer-duration interruptions simultaneously and in an integrated manner, and for regulatory processes to evolve accordingly.

9.6 Other topics

The New York and California case studies document how those two jurisdictions have addressed risk and uncertainty in their respective efforts to prepare for severe weather events. Uncertainty quantification and risk management are increasingly important in developing measures to reduce the risks of LDWIs. This raises the question of utilities' existing institutional capacities for conducting these types of analysis and for applying these analyses to storm-hardening and other projects. Risk considerations are a standard part of utilities' financial reporting compliance (e.g., to the U.S. Securities and Exchange Commission). It may be interesting to investigate the possibilities for bringing the expertise applied there to reliability and resilience planning. A related topic is regulated utilities' integrated resource planning capabilities, which often encompass sophisticated economic modeling and risk analysis. It is possible that these tools could be brought to bear on problems such as storm hardening and other strategies to mitigate future risk from extreme events.

9.7 Recommendations for further research

The case studies reveal a number of areas in which further research could be beneficial to utilities and regulators in dealing with risks associated with LDWIs.

Investigate the value of consistently collecting information on past extreme events

The case studies showed that utilities conduct detailed assessments of physical impacts of extreme weather events on their systems, and of response and recovery operations. These assessments form the basis of utility petitions to regulators for recovery of the associated costs. These petitions are based on standard cost accounting categories such as materials, labor, and other (e.g., providing emergency services to customers). However, utilities differ in what cost categories they report for the response to, and recovery from, power interruptions. Also, there is little or no information consistently reported on the past economic impacts from power interruptions initially caused by natural catastrophes. It follows that there may be value in consistently collecting – across utilities – data in the categories associated with damage to utility infrastructure and other costs associated with system recovery as well as impacts on customers. Consistently collecting this type of information could help identify and prioritize parts of the electricity system that may be more vulnerable to extreme weather or other threats.[46]

Improve economic analysis of impacts of long-duration widespread power interruptions
The case studies indicate a clear need to develop new estimates of avoided economic impacts of LDWIs on residential, commercial, and industrial customers as well as on the broader economy. Surveys should be designed using cutting-edge elicitation techniques to identify customer costs of interruptions that range from hours to weeks. Computational models for estimating not just regional, but also service-territory-level, economic impacts of LDWIs should be developed. This work should be integrated with the aforementioned survey design and empirical analysis of customer interruption costs. The aim of an integrated empirical-computational approach would be both to solidify the empirical foundations of the models (i.e., improve the assumptions used by the regional economic models) and to achieve synergies between the two methodologies in quantifying both direct and indirect economic impacts of interruptions.

As part of this effort, research should be conducted to assess the information gains from increased computational model complexity and detail, in order to avoid creation of overly complicated models that do not add value to utility planning and regulatory processes. This work should enable decision makers to understand the trade-offs between simpler and more complex models. Perhaps most importantly, new innovations in survey implementation and regional economic modeling should produce results that can be readily incorporated into existing decision-making processes (see below).

Determine factors that influence regulatory/utility adoption of economics information associated with long-duration widespread power interruptions
We have emphasized the importance of institutional influences on both utilities' technical approaches to event-preparedness planning and the regulatory processes within which such planning is conducted, as well as the need to take account of these influences when considering new methodologies and practices.

[46] There may be disincentives for some utilities to highlight the economic impact of past power disruptions. At the same time, some utilities may be incentivized to estimate these impacts in order to justify future investments in reliability/resilience. Additional research, including interviewing utility staff, could contribute to understanding the circumstances in which utilities are or are not motivated to conduct economic studies associated with past disruptions. Kihm et al. (2017) discuss these issues in more detail.

An important topic for research is to study what factors determine whether utilities, regulators, and other stakeholders may be willing to adopt economic information associated with LDWIs into existing regulatory and planning processes. Applied research should also investigate the steps necessary to facilitate adoption of this type of information by regulators and utilities in cases where reliance on this information would be appropriate. A "decision-centered" research philosophy is needed; existing institutional practices and methods must be understood and respected, and proposed innovations must be justified in terms of the perspectives of the utility and regulatory decision makers.

It seems likely that the lack of available methods and data required to estimate certain economic impacts of power interruptions means that the total economic impacts of extreme weather events on the electricity sector are consistently under-estimated. For example, in the preceding case studies, estimates of direct impacts on customers are often missing, and estimates of indirect impacts throughout the economy or society are always missing from the regulatory process. If it is indeed the case that economic impacts are being under-estimated, then this would naturally lead to under-investment in storm-hardening and preparedness programs. To a large extent, the greater availability of information about the costs of physical damage to electricity system infrastructure is a consequence of the fact that utilities bear these costs directly and have procedures for recovering them whereas the costs of the power interruptions are borne by other parties (i.e., customers, people living outside of the regulated jurisdiction) who generally cannot recover their resulting losses. Therefore, it seems that research on regulations and policy designs that incentivize utilities to capture the benefits of potential hardening and preparedness programs to their customers would be valuable for realizing the socially optimal level of investment.

Assess how utilities might incorporate risk and uncertainty analysis into existing analytical practices

Risk and uncertainty quantification and management do not appear to be widespread in utility storm-hardening analysis and planning. However, risk and uncertainty associated with economic impacts increase significantly as power interruption durations increase. A topic for research is to assess how utilities might begin to incorporate risk and uncertainty analysis into their planning in a way that builds on, and complements, their existing analytical practices. One question is whether risk assessment methods used in utilities' financial reporting might be brought to bear; another is how utility integrated resource planning models and methods might be applied.

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Appendix A. Additional details for New York case study

Table A-1. Information on storm Sandy response and recovery reported by Consolidated Edison to the New York Public Service Commission (from Con Ed 2013a)

I. Executive summary	
II. Tracking the developing storm	Monitoring and analysis of weather forecasts
III. Pre-storm preparations	Generation & transmission/ substation system preparations
	Distribution system preparations
	Transmission right-of-way vegetation management
	Tree trimming
	Transmission and distribution systems operations during storm
	Substation system hardening
IV. Impending storm preparations	Pre-arrival
	Implementation of company-wide coastal storm plan
	Steam system preparations
	Gas system preparations
V. Event classification	Storm emergency classification matrix
VI. Storm impact	Overview of major outage incidents during Sandy
	Preemptive network shutdowns – Description of outage incident
	Automatic shutdown of eleven networks in Manhattan – Description of outage incident
	Automatic shutdown of three area substations and associated load areas in Staten Island – Description of outage incident
	Interruption of power to customers supplied from non-network, radial (overhead) load areas – Description of outage incident
	Transmission system impact
	Customer outages
	Storm comparison – number of electric customer interruptions
	Steam system impact and customer outages
	Gas system impact and customer outages
	Storm related costs
VII. Restoration response	Crew assignment • Control center/ trouble analysis staff • Line clearing/ public safety crews • Damage assessment • Site safety • Restoration crews
	Restoration priorities
	Resource mobilization • Company resources • Damage assessors • Site safety
	Mutual assistance • Background • Preparation/ response to Sandy
	Staging area and base camps
	Customer outage totals
	Restoration strategy

	• Bulk power system and substations restoration strategy • Restoration of the East 13th Street and East River substations and associated substations and networks • Restoration of the other Lower Manhattan and Brooklyn networks • Restoration of Staten Island transmission facilities
	Estimate time of restoration
	Steam system restoration
	Gas system restoration
	Coastal area response
VIII. Stakeholder communications	Media contacts
	Government outreach
	E-mail, Web, and social media
	Central Information Group
	Con Edison emergency management
	Various emergency operations centers
	Communications prior to Super storm Sandy (Oct. 23-29, 2012) • Communications with New York State and federal agencies and departments • Communications with New York City agencies and departments • Communications with Westchester County agencies and departments
	Communications during Super storm Sandy (Oct. 29-30, 2012)
	Communications during restoration (Oct. 30, 2012)
	Customer communications • Outbound call campaigns • Calls made prior to and after the storm
	Calls to life-sustaining equipment customers predicted to be without service
	County-specific messages at the call center
	Outbound calls to inform customers of estimated time of restoration
	Large customers
	Communicating with steam customers
	Reporting emergencies at the call center
	Communications with at-risk customers
	Critical care customers
	Emergency generators deployment
	Customer outreach efforts during Super storm Sandy
	Dry ice distribution/ restoration services
	Command post/restoration center support
	Claims
IX. Lessons learned	
X. Appendices	Appendix A – Tropical storm force wind extent
	Appendix B – Strongest tropical cyclones in the Atlantic basin
	Appendix C – National Hurricane Center track maps
	Appendix D – Simplified certification process
	Appendix E- Restoration update for flood-damaged communities
	Appendix F – Press releases
	Appendix G – Blast email
	Appendix H – Online outage map
	Appendix I – Website storm display

	Appendix J – Central Information Group external notifications
	Appendix K – Liaison officer log
	Appendix L – County specific messages
	Appendix M – Communications with steam customers

Table A-2. Information on incremental costs of storm Sandy response and recovery reported by Consolidated Edison to the New York Public Service Commission (from Con Ed 2013c)

I. Contract services	Mutual aid
	Contract labor
	Contractor – tree trimming
	Equipment/material & repairs
	Telecommunications – Call center
	Telecommunications – other
	Base camp services
	Base camp – materials and supplies
	Flagging & site safety
	Ice
	Environmental
	Food & lodging
	Guard services
	Generator – fuel, rental & operations
	Miscellaneous contractor services
II. Company labor	Man-hour labor
	Management
	Weekly
III. Materials & Supplies	Stores handling
	Electrical installments & replacements
	Mechanical repair & maintenance
	Maintenance & repairs – other
	Fuel – gasoline & diesel
	Fuel – staging areas
	Miscellaneous materials & supplies
IV. Other	Employee expenses
	Freight charges
	Transport material
	Rentals
	Rental – Crane service
	Miscellaneous

Additional details on Con Ed's Risk Assessment and Prioritization Model

For a given type of infrastructure and impact type, the tool computes an "event impact" metric *I* defined by:

$$I = Population\,(or\ equivalent)\ affected \cdot Outage\ duration$$

where "population" refers to residential and commercial customers, and "equivalent" refers to the infrastructure types mentioned above. Con Ed calculates these "population equivalents" using formulae it has developed.

Con Ed uses a flood inundation model and historical statistical information on wind gust frequencies combined with Monte Carlo simulation to estimate conditional probability distributions of flood- or wind-induced infrastructure or equipment failure with and without the resilience measure or investment. The risk of an event is then defined as:

$$Risk = I \cdot Failure\ probability\ (conditional\ on\ measure),$$

where "conditional on measure" indicates that these probabilities are calculated both assuming that the measure is undertaken, and that it is not. For a given resilience measure or investment M, let $\Delta\, Prob(M)$ be the change (reduction) in the failure probability resulting from the measure or investment, and $\Delta\, Risk$ the corresponding change in risk. Then:

$$\Delta\, Risk = I \cdot \Delta\, Prob(M).$$

This quantity is normalized into a "risk reduction priority score" taking on values between zero and one.

Appendix B. Additional details for California case study

Provisions of California Senate Bill (SB) 901, Public Utilities Code 8386(c), 2018 – Wildfires

(1) An accounting of the responsibilities of persons responsible for executing the plan.

(2) The objectives of the plan.

(3) A description of the preventive strategies and programs to be adopted by the electrical corporation to minimize the risk of its electrical lines and equipment causing catastrophic wildfires, including consideration of dynamic climate change risks.

(4) A description of the metrics the electrical corporation plans to use to evaluate the plan's performance and the assumptions that underlie the use of those metrics.

(5) A discussion of how the application of previously identified metrics to previous plan performances has informed the plan.

(6) Protocols for disabling reclosers and de-energizing portions of the electrical distribution system that consider the associated impacts on public safety, as well as protocols related to mitigating the public safety impacts of those protocols, including impacts on critical first responders and on health and communication infrastructure.

(7) Appropriate and feasible procedures for notifying a customer who may be impacted by the de-energizing of electrical lines. The procedures shall consider the need to notify, as a priority, critical first responders, health care facilities, and operators of telecommunications infrastructure.

(8) Plans for vegetation management.

(9) Plans for inspections of the electrical corporation's electrical infrastructure.

(10) A list that identifies, describes, and prioritizes all wildfire risks, and drivers for those risks, throughout the electrical corporation's service territory, including all relevant wildfire risk and risk mitigation information that is part of Safety Model Assessment Proceedings and Risk Assessment Mitigation Phase filings. The list shall include, but not be limited to, both of the following:

> (A) Risks and drivers associated with design, construction, operations, and maintenance of the electrical corporation's equipment and facilities
> (B) Particular risks and risk drivers associated with topographic and climatological risk factors throughout the different parts of the electrical corporation's service territory.

(11) A description of how the plan accounts for the wildfire risk identified in the electrical corporation's Risk Assessment Mitigation Phase modeling.

(12) A description of the actions the electrical corporation will take to ensure its system will achieve the highest level of safety, reliability, and resiliency, and to ensure that its system is prepared for a major event, including hardening and modernizing its infrastructure with improved engineering, system

design, standards, equipment, and facilities, such as undergrounding, insulation of distribution wires, and pole replacement.

(13) A showing that the utility has an adequately-sized and trained workforce to promptly restore service after a major event, taking into account employees of other utilities pursuant to mutual aid agreements and employees of entities that have entered into contracts with the utility.

(14) Identification of any geographic area in the electrical corporation's service territory that is a higher wildfire threat than is currently identified in a [California Public Utilities Commission (CPUC)] fire threat map, and where the [CPUC] should consider expanding the high fire threat district based on new information or changes in the environment.

(15) A methodology for identifying and presenting enterprise-wide safety risk and wildfire-related risk that is consistent with the methodology used by other electrical corporations unless the [CPUC] determines otherwise.

(16) A description of how the plan is consistent with the electrical corporation's disaster and emergency preparedness plan prepared pursuant to Section 768.6, including both of the following:

> (A) Plans to prepare for, and to restore service after, a wildfire, including workforce mobilization and prepositioning equipment and employees.
> (B) Plans for community outreach and public awareness before, during, and after a wildfire, including language notification in English, Spanish, and the top three primary languages used in the state other than English or Spanish, as determined by the [CPUC] based on United States Census data.

(17) A statement of how the electrical corporation will restore service after a wildfire.

(18) Protocols for compliance with requirements adopted by the [CPUC] regarding activities to support customers during and after a wildfire, outage reporting, support for low-income customers, billing adjustments, deposit waivers, extended payment plans, suspension of disconnection and nonpayment fees, repair processing and timing, access to utility representatives, and emergency communications.

(19) A description of the processes and procedures the electrical corporation will use to do all of the following:

> (A) Monitor and audit the implementation of the plan.
> (B) Identify any deficiencies in the plan or the plan's implementation and correct those deficiencies.
> (C) Monitor and audit the effectiveness of electrical line and equipment inspections, including inspections carried out under the plan and other applicable statutes and [CPUC} rules.

(20) Any other information that the [CPUC] may require.

SAN DIEGO GAS & ELECTRIC COMPANY WILDFIRE MITIGATION PLAN, FEBRUARY 6, 2019: CONTENTS

California Electric Utilities Fire Incident Data Reporting template

Utility Name	
Fire Start	• Date • Time
Location Info	• Latitude • Longitude • Material at Origin (vegetation, building, other) • Land Use at Origin (Rural, Urban)
Fire Specifics	• Size (in acres) • Suppressed by (e.g., fire agency, utility, customer) • Suppressing Agency
Utility Facility	• Utility Facility Identification • Other companies involved (if any) • Voltage • Equipment Involved with Ignition (e.g., conductor, fuse, transformer) • Type (in almost all cases, this is "overhead")
Outage Info	• Was there an outage (yes or no) • Date, time (apparently, of onset)
Field Observations	• Equipment/Facility Failure (e.g., splice/ clamp/ connector for overhead) • Contact from Object (e.g., vegetation) • Facility Contacted (electric, communication, pole) • Contributing Factor (e.g., weather, human error, unknown) • Notes