Grid reliability in a changing climate

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Executive Summary

As the United States continues to experience disastrous weather-related events—hurricanes, tropical storms, deep freezes, heat waves, and wildfires—evaluating the resilience of critical infrastructure systems becomes increasingly important. Today's changing climate is making the case for resiliency efforts across communities and grid reliability becomes especially important for communities dependent on our century-old power grid.

The interconnected capability of the U.S. power grid is evolving rapidly and the energy landscape is covering new terrain. The emergence of advanced technologies, climate policies, and restructured energy markets represent the vast opportunity for developing a more reliable grid. This study looks at resiliency through the lense of preventative and recovery (reactive) efforts for enhancing grid reliability during times of severe weather events. Ideally, these efforts eliminate undue costs resulting from infrastructure damage and power outages, among other consequences.

We explicitly consider alternatives—namely distributed energy resources (DERs)—to conventional energy generation and capacity resources to support the grid during demand constraints. Enhanced grid services unique to DERs are also highlighted. We also advocate for permanent hardening measures, such as burying distribution lines and waterproofing substations, that protect the grid against repeat failures from recurring events. Grid hardening and DERs are both likely to play a major role in stabilizing the grid and maintaining electric service in the years to come.

Addressing climate change risks must account for both the capital costs to implement resilience measures and the benefits of grid reliability during and after weather-related events. Economic analyses presented in the case studies consider "damage cost avoidance" where both direct and indirect costs of damage are taken into account. We believe this approach aids in screening resiliency measures for cost-effectiveness when applied to future (hypothetical) events.

This study introduces a different approach in assessing grid reliability and how we might establish a more resilient grid by thinking outside the "utility toolbox". Our intent is not to provide an exhaustive list of the potential resiliency measures and recovery efforts that utilities could consider, nor do we come close to capturing all of the benefits to the grid's many stakeholders. This study provides just a glimpse of what's possible today. We hope that the possibilities are endless.

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Background

Nearly 150 years ago, the U.S. energy sector we know today took rudimentary shape. Its conventional power generation, transmission, and distribution systems have expanded to meet substantial load growth and maintain grid reliability over the years. Today, 70% of the grid's transmission lines and transformers are over 25 years old, and fossil fuel and nuclear power plants average over 30 years (DOE 2014). In the 21st century, our interconnected society and changing climate are confronting business-as-usual thinking and placing pressure on the grid to adapt to changing circumstances. Distributed energy resources (DERS) are increasingly being considered as a viable option in meeting this challenge.

> Distributed energy resources (DERs) are energy generation and storage resources (e.g., PV, batteries) connected to the grid and placed strategically along the distribution network (ABB 2019).
>
> Others define DERs more broadly to include distributed generation and storage, but also energy efficiency, demand response, electric vehicles, and strategic electrification technologies (NESP 2017).

Grid reliability

Grid reliability requires precise operations, where energy supply is balanced with demand at all times. Supply-side stakeholders—power producers, RTOs/ISOs, and utilities—each play a role to ensure that transmission systems (large power flows across long distances) and distribution systems (networks reaching end users) are safe and reliable. The majority of grid upgrades are driven by the rehabilitation of aging infrastructure, fossil fuel plant retirements, and changes in reliability standards.

Restructured energy markets represent a new model for enhancing grid reliability. For example, we see transmission operators incorporating demand-side resources into restructured markets to ensure the reliable delivery of electric service to end users. Ancillary services[1] can be disaggregated from the wholesale price of energy to associate a value to each service. For instance, demand reduction resources in PJM and ISO-NE market auctions demonstrate that ancillary services are functionally equivalent to and potentially cheaper than producing additional conventional power for keeping supply and demand in balance (RAP 2010).

One of the main benefits of ancillary services is their potential to defer utility investments in new generation capacity and distribution upgrades necessary to meet projected load growth (RMI 2015). In February 2018, FERC issued Order No. 841 requiring system operators to remove barriers to energy storage in the capacity, energy, and ancillary services markets. The Order requires each ISO/RTO to revise its tariff to include market rules that recognize the physical and operational characteristics of storage resources (EIA 2018a). In the "utility of the future",

[1] Ancillary services beneficial to the ISO/RTO include spin and non-spin reserves, energy arbitrage (load following & demand response), frequency and voltage balancing, and black starts (RMI 2015).

demand-side management and alternative capacity resources become integral to utility resource planning (ICF 2017).

Energy storage resources now participate as load capacity and compete in deregulated markets. For instance, ISO-NE has developed a market design based on performance, intended to provide financial incentives for capacity resources that come online during scarcity conditions and enhance system reliability (NERC 2018). This relationship could determine a market value for resilience measures and their fate in resource planning; it essential allows a price to be placed on the value of reliability served by DERs, where lost sales opportunities become evident (EIA 2018a). NERC-assessed penalties for failing to meet regulatory requirements also provide insight into the cost of *not* investing in reliability.

Grid vulnerability

Millions of miles of low-voltage and high-voltage transmission and distribution lines and numerous equipment components span the U.S. power grid. Massive in scale, much of the grid is prone to extreme weather events and severe impacts. Electricity distribution assets—having little redundancy—are most vulnerable to weather events. In fact, the majority of power outages in the U.S. result from damage to distribution lines with the majority of outages affecting local, low-voltage distribution systems (EPRI 2013, GEI 2011).

In a changing climate, the vulnerability of our interconnected power grid is amplified; grid system performance can become significantly impacted by extreme weather events and natural disasters. These threats also expose the vulnerability of communities which depend on the grid for their vitality. Nearly all regions in the U.S. are experiencing variations in annual climate patterns: precipitation levels, heating and cooling degree days, ambient temperature ranges, and seasonal durations. Even insect, fish, and other animal migration behaviors are shifting course. A changing climate can create unpredictable weather conditions leaving communities defenseless.

> Year-to-year trends show a lengthening wildfire season in the United States. Historically only occurring in the hottest months of the year, wildfires are starting earlier and ending later. Climate models also predict hotter temperatures and prolonged periods of drought in the future, which will only make for more dangerous conditions in the western states.
> Sources: NASA 2015, WRI 2019

Weather-related disasters—extreme heat waves and cold snaps, droughts and fires, and intense storms and flooding—pose significant threats to the power grid by placing pressure on aging infrastructure and increasing operation and maintenance costs. Nonetheless, grid resiliency efforts remain underdeveloped and undervalued in the energy sector. For instance, the widespread damage and resulting litigation claims from the 2017-2018 California wildfires have driven one large utility out of business.

In recent years, resiliency planning has become a priority for local leaders and supporting organizations. For example, the Rockefeller Foundation's 100 Resilient Cities and ICLEI's Resilient Cities forums coordinate resiliency efforts with urban planning activities (100 Resilient Cities 2019; ICLEI 2017). Resiliency planning at the energy sector level is nascent, however; there is no coordinated approach for valuing grid resiliency. Meanwhile, state and city governments are reforming the power grid indirectly through climate policies aimed at increasing public health and safety. Governors and mayors are establishing clean and renewable energy targets to curb global carbon emissions and promote economic opportunity.

Methods and Purpose

Subjects

In this report, the *utility system* refers to all elements of the grid necessary to deliver electricity service to utility customers or, more broadly, end users. The system includes all electricity services: generation, transmission, distribution, O&M, and ancillary. The term *utility* covers any type of utility ownership or management, including investor-owned utilities, publicly-owned utilities, municipal utility systems, and cooperatives. For the purpose of evaluating specific resiliency applications, this study presents the investor-owned utility (IOU) as the subject in two case scenarios.

The focus of the report is grid reliability in the face of weather-related events, such as hurricanes, tropical storms, deep freezes, heat waves, and wildfires. Grid reliability becomes synonymous with resilience and is approached from two management angles: preventative and reactive. Cost-effective grid hardening measures and enhanced grid services unique to distributed energy resources are discussed. Impacts on utility system infrastructure, capacity constraints, and capital investment costs are explored. This study does not intend to provide an exhaustive analysis nor capture all potential resiliency measures and benefits that electric utilities can consider.

A literature review was conducted to obtain much of the information herein. Facts and data were culled from a variety of current sources, including industry news articles, trade and scientific journals, utility resource planning and financial reports, and state government records. Two real-world case studies are presented. The economic analyses in the case studies are original to the author of this report. Less common terms and concepts are defined in footnotes.

Purpose

The purpose of this study is to explore the benefits of "grid hardening" measures to prevent or lessen grid disruptions caused by weather-related events, such as hurricanes, tropical storms, wildfires, and extreme temperatures. Distributed energy resources are presented as a viable option in supporting the electric grid during disruptions, mainly power outages. Both preventative and emergency response efforts are explored, and their associated costs.

The relevance of this topic is that disruptions to the power grid are primarily weather-dependent, as opposed to disruptions independent of weather, such as utility operations and maintenance activities. As shown in Figure 1, the prevalence of weather-related power outages[2] in the US has been increasing steadily since 2003 (Climate Central 2014). Therefore, utility system performance is dependent upon the impact of weather-related events and, more importantly, the ability to recover from them.

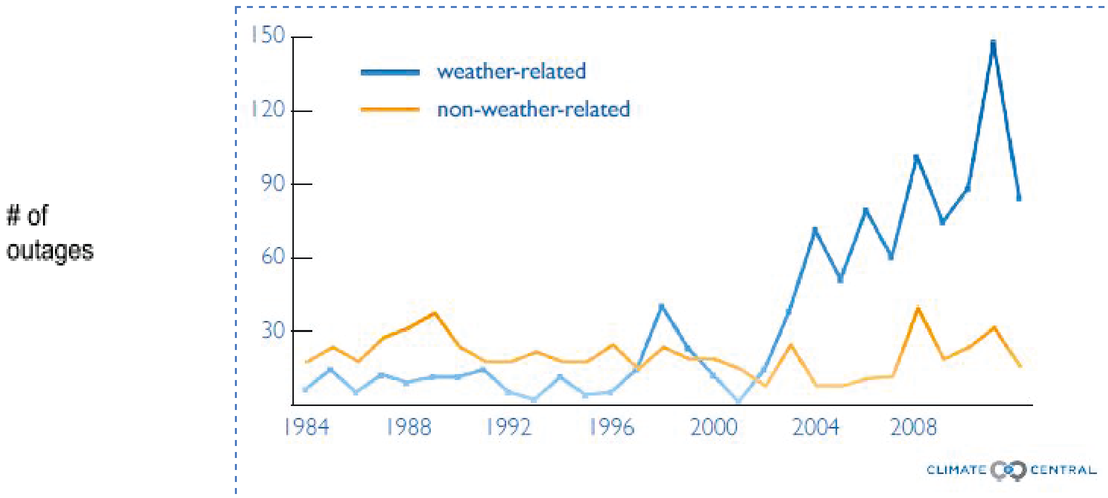

Figure 1. Weather- and non-weather-related power outages experienced by U.S. electric utilities. *Source:* Climate Central 2014.

This study evaluates grid hardening measures and DERs through the lense of resiliency. The goal is to highlight the benefits and challenges in establishing a resilient power grid. As positioned in this report, grid resilience is achieved through two means: 1) proactive or preventative, such as implementing grid hardening measures to prevent utility infrastructure damage; and 2) reactive, as in emergency response, such as deploying distributed energy resources to support grid services during power outages.

Analysis of Grid Hardening Measures

Most U.S. communities are vulnerable to the impacts of climate change where their local interdependent systems rely heavily on the larger power grid. For example, more extreme storms and higher storm surges stress aging infrastructure, resulting in greater property

[2] Large electrical disturbances (including blackouts, voltage losses, load shedding, fuel supply emergencies, and emergency appeals for reduced electricity usage) during which at least 50,000 customers were affected. The power supply disruption amounts to at least 300 MW, or the demand for electricity exceeded the supply by at least 100 MW.

damage. Extreme high temperatures amplify the urban heat island effect[3] in cities, leading to higher cooling needs in buildings and a corresponding increase in electrical demand.

Major weather events often present utilities the opportunity to prioritize investments in utility system upgrades. For example, Florida Power & Light (FPL) has invested more than $3 billion in grid hardening measures since 2006. FPL claims a 40% decrease in system impacts and a 50% increase in power restoration time just by hardening its distribution lines (FPL 2019).

> Over the past decade, Florida Power & Light (FPL) has implemented grid hardening measures, such as: 1) replacing wood power poles with stronger materials to withstand higher wind speeds; 2) installing more poles in order to increase redundancy and shorten the span between poles; 3) rerouting 43% of power lines underground; and 4) inspecting electrical equipment using advanced infrared technology so to accurately identify and repair weakening components before failure.
>
> Proactive pole replacements proved effective for FPL when compared across two storms: Hurricane Irma (cat. 4) cost the utility 4,600 damaged poles in 2017, compared with 12,400 poles from Hurricane Wilma (cat. 3) in 2005.
>
> An additional benefit of grid hardening is that power can be restored faster after a storm. FPL was able to restore 50% of customers (~2 million accounts) within 24 hours after Irma hit, compared to five days following Hurricane Wilma.
>
> Source: FPL 2019

Advanced technological capabilities (e.g., remote monitoring, high resolution, rapid response times) and sophisticated modeling and improved data (e.g., climate, seismic) allow for better understanding of the relationship between the natural and built environment. Interdisciplinary partnerships are forming across the public sector, private industry and academia to grasp the impacts of climate change. The hope is for resiliency best practices that can be brought to scale and applied across interdependent systems.

The Role of Risk Assessment

Risk assessment has long been a common concept across many types of finance and management applications. Risk assessments are used broadly in policy development, as demonstrated in climate action and sustainable development planning. For example, integrated assessment models lend a hand in evaluating economic-environmental scenarios to support policy decision-making (Zachary 2018).

It is common knowledge that climate change amplifies risk, especially in high-vulnerable, low-resilient systems. However, the risks associated with climate change are vast and differ across regions and industries. Even when risk is identified, it is difficult to quantify. Assessing

[3] Driven by the predominance of dark, impermeable surfaces such as asphalt, roofs, and pavement, and sparse vegetation. Dark, impermeable surfaces absorb heat during the day—conventional asphalt can reach summertime temperatures of 120–140°F—and release heat during the evening, which increases nighttime temperatures. Urban areas generally lack the benefits of vegetation and water bodies, which provide natural cooling via shade from the tree canopy and the release of water vapor. These factors lead to increased electricity use for indoor cooling needs.

the impacts of climate change requires accounting for numerous interrelated variables, many of which are constantly changing.

Broadly speaking, the scale of risk to any entity is a function of the hazards it faces, its vulnerability to those hazards, and the capacity to cope with unfavorable impacts. The United Nations developed one of the early formulas for assessing climate change risk:

$$\frac{\text{Hazards} * \text{Vulnerability}}{\text{Capacity to cope}}$$

Source: UNISDR 2004

The above formula displays three interdependent factors useful in the early assessment. One can conclude from this that the benefits of resiliency are to diminish “vulnerability” and increase “capacity to cope” thereby decreasing risk. The formula is purposely broad so to apply across a host of perspectives. From the utility’s perspective, the risk factors can be assigned to the utility system in the following way:

1. ‘Hazards’ include weather events and natural disasters that cause disruptions on the grid, most notably power outages.
2. ‘Vulnerability’ is the likelihood that the hazard will significantly impact the performance of the grid, jeopardizing electric service reliability and increasing operational costs.
3. ‘Capacity to cope’ is the system’s ability to resist and recover from widespread damage caused by extreme weather events, as through the deployment of grid hardening measures.

In the interest of all stakeholders, utilities need to learn how best to guard against premature failures and increase grid resiliency. Risk assessments allow ideas to emerge for solutions. However, in many circumstances, much of the data needed to form a complete analysis is incomplete or inaccessible. Shadow prices[4] are often used to account for the costly effects and externalities of extreme weather events and natural disasters. Unlike carbon dioxide (CO2), where values and proxies for the CO2 reduction benefits of different energy resources and policy activities are now widely accepted, common values representing risk factors cannot and should not be applied broadly across all U.S. communities (ACEEE 2018).

Absent hard data, risk assessments serve as mere guidelines for resiliency efforts. Nonetheless, their holistic approach and multi-stakeholder appeal serve a great purpose in community planning efforts. We might succeed at quantifying risk by first assigning a value to common hazards: hurricanes, wildfires, deep freezes, heat waves, etc. The private sector, namely utilities, would likely benefit from risk assessments that can relate the impacts of climate change to the costs of doing business.

[4] the assignment of a dollar value to an abstract commodity that is not ordinarily quantifiable as having a market price but needs to be assigned a valuation to conduct a cost-benefit analysis (Investopedia 2019).

The Role of Cost-Effectiveness Assessment

Energy resource planning is typically conducted through established cost tests that represent the specific costs and benefits of different investments. Such tests highlight and prioritize resources having low cost and long life expectancies. In the case for increasing grid reliability, utility investments in distribution infrastructure become important and cost tests become a useful tool. Investment decisions often result in new substations; however, grid hardening measures (e.g., stormproof poles and transformers, buried wires) and distributed storage technologies are increasingly being considered.

The cost of capital is a key variable in determining the cost-effectiveness of grid upgrades. Discount rates applied to capital are used to assess the time value of money for capital investments (and the opportunity cost for alternative investments). However, the cost of capital is not the only factor in investment decisions. Cost-effective assessments can weigh societal benefits—environmental, public health and safety, and equity—against hard costs. For example, a large new nuclear plant could be assumed to have both high construction costs and environmental risks, thereby producing no net benefit in either direction. Societal cost-effectiveness tests include the values and priorities of communities, such as managing socio-economic issues and cleaning polluted air and water sources. Ideally, they produce long-term benefits and address the needs of multiple stakeholders.

> While the upfront costs of distributed energy resources can be higher than conventional energy resources in some markets, the environmental risks of DERs are generally low, revealing benefits that compete directly with the costs of procurement. The benefits of DERs may exceed those for conventional resources, and prevent environmental damage (e.g., CO_2 emissions), economic crises and other risks to society.

As the risks of climate change gain greater attention and concern, policymakers and regulators are responding—U.S. states are enacting clean energy legislation and public service commissions are requiring utilities to commit to diversified energy sources in their integrated resource plans. Thus, the utility cost-effective model begins to look beyond the cost of capital and a more dynamic analysis comes into play.

Assessment type	Description	Goal	Perspective
Utility	Includes the costs and benefits experienced by the utility system.	Reduce utility system costs	Utility
Societal	Includes the costs and benefits experienced by society as a whole.	Reduce costs to the community	Society
Comprehensive	Includes the utility system costs and benefits, plus those costs and benefits associated with achieving relevant applicable policy goals.	Reduce utility system costs while achieving policy goals	Regulator and policymaker

Table 1. Comparison of cost-effectiveness tests. *Source*: NESP 2017

A comprehensive assessment approach identifies utility resources that can best serve customers over the long term, while also meeting applicable policy targets set by policymakers. They incorporate the quantitative costs of utility system improvements with the qualitative benefits [to society]. Much debate about “who pays” exists between the IOU and its customers. Comprehensive cost-effective assessments might guide regulators when deciding rate cases. This approach holds the potential for valuing enhanced services that resiliency measures can lend the utility system, including capital cost avoidance.

Typical benefits of “cost avoidance” include deferring system expansions to meet increasing demand and eliminating asset damages caused by extreme weather events. Other less-known but equally important utility costs include potential legal and political ramifications following a disaster. They can be the cost of deferred maintenance or neglect—the cost of doing nothing.

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PG&E Case Study

Background

The state of California's electric grid has six times more miles of distribution lines than transmission lines. Roughly 2% of all transmission lines and 33% of all distribution lines in the State are buried underground. The high rate of underground distribution lines is due in large part to Electric Tariff Rules 15 and 16 requiring all new line extensions be installed underground. However, the amount of buried lines varies greatly among the three largest IOUs operating in California (CPUC 2019).

	Distribution lines (miles)		
3 largest California IOUs	Overhead	Underground	% buried
PG&E	81,000	18,000	18%
SCE	52,731	39,607	43%
SDG&E	9,049	14,719	62%

The Pacific Gas and Electric Company (PG&E) is one of the largest natural gas and electric energy companies in the United States, serving over 16 million Californians in central and northern CA (PG&E 2019a). PG&E's service territory covers 70,000 sq. miles, with over 25,000 miles of overhead distribution lines located in Tier 2 and Tier 3 High Fire Threat Districts (HFTD).[5] PG&E has more service lines in HFTDs than SCE and SDG&E combined: approximately 65% of distribution lines in fire-prone areas belong to PG&E, and more than 100 million trees are immediately adjacent to PG&E's overhead lines (PG&E 2017).

Distribution Overhead Assets	
HFTD Area	**Line Miles***
Zone 1	100
Tier 2	18,000
Tier 3	7,100
Total	**25,200**

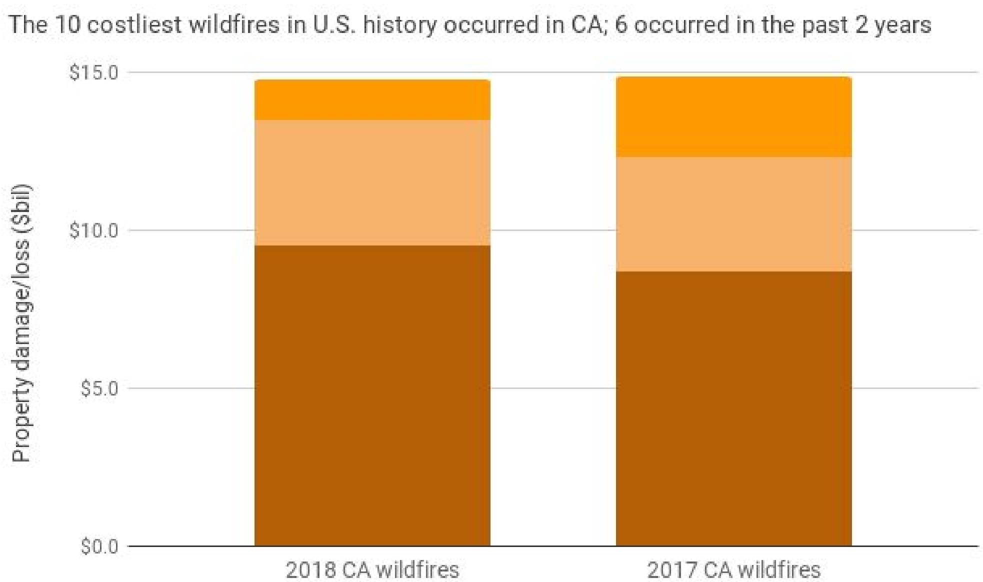
The California Public Utilities Commission (CPUC) regulates investor-owned electric and natural gas utilities operating in the state. In collaboration with the California Department of Forestry and Fire Protection (CAL FIRE), the CPUC Safety and Enforcement Division designated statewide HFTDs in 2018. HFTDs represent areas with elevated risk for power line fires igniting and spreading rapidly (CPUC 2018).

[5] Tier 2 and Tier 3 HFTD represent elevated and extreme risk for utility associated wildfires, respectively; Zone 1 represents areas of high tree mortality, where dead trees are potential fuel for wildfires, which then impacts utility infrastructure in the area. See HFTD map in Appendix A.

California Wildfires

Based on historical weather patterns, extreme fire danger in PG&E's service territory occurs in June and then again in September and October. However, a persistently dry fall and later start to the wet season have extended extreme fire risk later into the year. In the 2017 and 2018 wildfire seasons, there was risk of wildfires occurring at almost any time (WRI 2019).

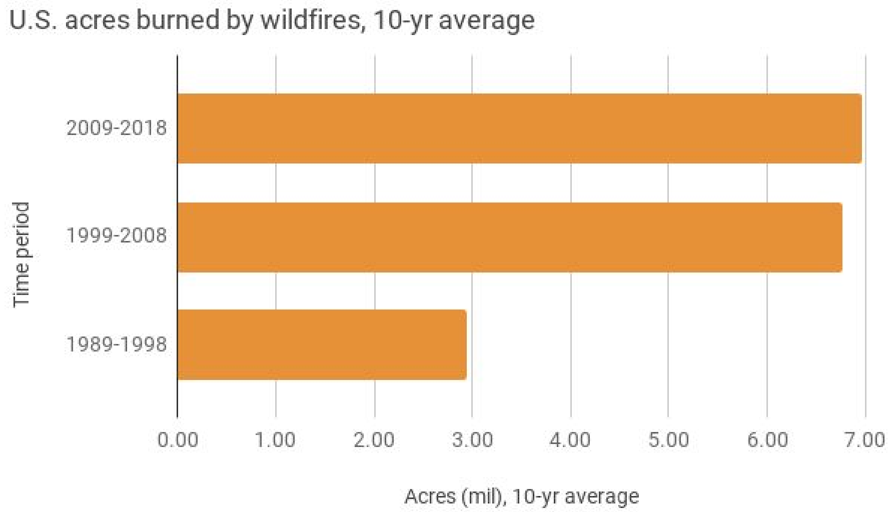
The disastrous wildfires of 2017 and 2018 took the lives of over 100 people and destroyed hundreds of thousands of acres in California; the 2017 Tubbs Fire resulted in 23 deaths and the 2018 Camp Fire 86 deaths—the deadliest fire in California to date. Wildfire-related damages exceed $30 billion when accounting for these two fires and smaller related fires. The ten costliest wildfires recorded in U.S. history occurred in California; six of them occurred in 2017-2018 (WRI 2019).



2017 CA Wildfires	Tubbs Fire Oct. 8-20 $7.7-$9.7 bil	Atlas Fire Oct. 8-20 $2.6-$4.6 bil	Thomas Fire Dec 4 - 23 $1.5-$3.6 bil	**$11.8-$17.9 billion**
2018 CA Wildfires	Camp Fire Nov. 8-25 $8.5 - $10.5 bil	Woolsey Fire Nov. 8-22 $3.0-$5.0 bil	Carr Fire Jul. 23-Aug. 30 $1.0-$1.5 bil	**S12.5-$17.0 billion**

Source: Insurance Information Institute 2019

The amount of U.S. acres burned by wildfires has increased significantly over the past 20 years. The size of wildfires more than doubled in 1999-2008 compared to the previous 10-year period, then held steady in 2009-2018 increasing just 1% (NIFC 2019).



The consensus on the cause of the CA wildfires fires is high winds knocking power lines into trees (St. John 2018). California utilities have begun pointing to climate change impacts as the culprit: 1) years of increasing drought, 2) dry and dead forest timber, 3) wet winters followed by abundant vegetation growth, 4) record-setting summer temperatures and low humidity, and 5) very high winds. Utilities are forming a consensus around climate change: climate change directly contributes to wildfires, and liability rules should reflect a “new normal” that accounts for increased risks.

“If we are operating the system and we’ve done everything we can and yet the environment around us causes a problem that leads to a large disastrous fire, the (legal) structure needs to be modernized to reflect today’s new challenges.” - Eugene Mitchell, VP of San Diego Gas & Electric (Rosenhall 2018).

Competing policies

In 2018, California passed the first-of-its-kind wildfire bill. SB 901 authorizes the CPUC to apply “reasonableness tests”[6] in determining which costs can be passed on to ratepayers, versus those that borne by the utility. Essentially, the bill grants utilities permission to pass some wildfire-related costs (at the CPUC’s discretion) on to ratepayers for fires that occurred in the year 2017 and prior.

SB 901 challenges the longstanding “inverse condemnation law” in California that protects property owners and insurers. The CA Constitution gives utilities eminent domain rights—the power to take private land for public use—with the caveat that utilities are then liable for damages caused by their equipment, regardless of negligence. In general, inverse condemnation entitles property owners to just compensation, and the right to sue, if their property is damaged by a public entity, including utilities. In the wake of the disastrous wildfires in recent years, inverse condemnation has provided a legal course of action for fire victims in California to recover wildfire-related damage costs (LOCC 2018). Without litigation rights, insurance companies will likely charge owners more for premiums.

PG&E and other CA utilities, fearing that inverse condemnation could financially cripple them, pushed for legislative changes in early 2018 that ultimately led to the passing of SB 901. Property owners and insurance companies want to keep the existing inverse condemnation law alive—they

[6] During ratemaking proceedings, the CPUC can establish rates that allow an investor-owned utility to recover certain damage costs from ratepayers, if the utility is deemed by the CPUC to have acted reasonably (LOCC 2018).

see it as the only “legal incentive” to strongarm utilities into upgrading the electric grid with more wildfire-resilient features.

While SB 901 provides some liability relief for utilities, damage costs associated with the 2018 Camp Fire have yet to be settled. Litigation negotiations continue to be hashed out between PG&E and the state of California, as the State tries to grapple with how to ensure reliable energy services are provided to the millions of homeowners, businesses and industries in central and northern portions of the State. Litigation costs incurred by PG&E were enough to force the utility into bankruptcy.

Damage Cost Avoidance

Burying power lines—a process referred to as ‘undergrounding’—requires trenching and locating the lines 24” below grade [depth requirement]. This feat involves moving cable and phone lines and adding IOT capability, such as smart transformers and switches, allowing for remote-monitoring. Compared to overhead systems, O&M related costs are roughly half that for underground lines. That said, undergrounding power lines is not without setbacks, especially in flood-prone areas where buried power lines are subject to saturated soils which can lead to corrosion. The technical expertise for handling underground system failures becomes increasingly more specialized (Kury 2010).

In general, the costs associated with undergrounding power lines are approximately 10x that for overhead lines. A 2015 cost analysis by San Francisco’s budget and legislative office estimates a low cost of $1million/mile and a high estimate of $3.8 million/mile for undergrounding power lines (CCSF 2015).

PG&E paid more than $11 billion in 2018 in wildfire-related damage claims. In 2019, damage costs are projected at $900 million to $1.3 billion. Planned wildfire mitigation efforts on distribution lines could cost PG&E an additional $1.5 billion in 2019. All in, PG&E is looking at spending $13 to $14.5 billion in wildfire-related cost incurred over the two year period, 2018-2019 (PG&E 2019b,c,d).

DAMAGE COSTS

Wildfire-related damages	**PG&E damage responsibility, projected for 2019 ($mil)**	
	low	high
2018 Camp Fire	$190	$260
2017 fires	$40	$90
Emergency inspections	$300	$450
Chapter 11 expenses	$400	$460
Total damage costs, proj. in 2019	**$930**	**$1,260**
	PG&E damage responsibility, paid in 2018 ($mil)	
wildfire-related claims, (net insurance payouts)	**$11,771**	

Mitigation Activity (OH distribution lines only)	**Planned Wildfire Mitigation costs in 2019 ($mil)**	
	low	high
Veg. mgmt	$338	$424
System hardening	$237	$237
Safety Inspections	$330	$820
Total mitigation costs, est. in 2019	**$905**	**$1,481**

In calculating damage cost avoidance in future years, we use known costs of 2018-2019 as our benchmark. Wildfire-related damage costs for the 2-year period run $13.6 to $14.5 billion. Using a low and a high estimate, the investment costs for undergrounding PG&E's OH distribution lines in designated fire-prone areas run ~$25 billion to ~$96 billion.

CAPITAL COSTS

PG&E overhead (OH) distribution lines (miles)		Undergrounding costs ($mil/mile)		Total costs ($bil)	
		low	high	low	high
Total OH lines	81,000	$1.0	$3.8	$81.0	$307.8
OH lines in fire-prone areas	25,200	$1.0	$3.8	**$25.2**	**$95.8**

Damage cost avoidance is then determined through a simple benefit-cost analysis. The project has a best case payback period of 1.7 years (lowest investment/highest damage costs) and 7 years for worst case (highest investment/lowest damage costs). Similarly, the return on investment (ROI) ranges 2 to 8 years, using a 3% discount rate. We hold that these costs can serve as a benchmark for wildfire scenarios in future years.

Benefit-Cost Analysis

(damage cost avoidance)

Cost Summary	low cost scenario	high cost scenario
Total PG&E wildfire-related costs, 2018-2019 ($bil)	**$13.6**	**$14.5**
Undergrounding costs in fire-prone areas ($bil)	**$25.2**	**$95.8**
Cost Benefit[7]	best cost case	worst cost case
Simple Payback (yrs)	**1.7**	**7.0**
positive NPV* year	**2**	**8**

**3% discount rate used*

This analysis infers that undergrounding distribution lines in high fire-prone areas is a feasible investment. Given the persistence of droughts and heat waves year-after-year, wildfires are likely to continue in the coming years (Abatzoglou and Williams 2016). Even under the most robust climate change mitigation efforts, the atmospheric effects of CO_2 mitigation will take decades to materialize.

[7] See appendix B for full NPV analysis

To account for the frequency of wildfires changing over time, the NPV of future costs can be multiplied by the annual likelihood of recurrence.

This analysis evaluates the hard costs of the project to show investment value from the utility's perspective. It is reasonable and imperative for utilities to commit capital resources in protecting their assets and their customers. A comprehensive analysis would incorporate the perspectives of other stakeholders and may prove useful to regulators when evaluating rate cases that look to pass investments costs onto customers.

One resilience strategy PG&E is actively pursuing is *planned* power outages during times of high winds. This strategy will ultimately force over 5 million people located in fire-prone areas to go without power for periods of up to five consecutive days (Gold and Blunt 2019).

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Analysis of Emergency Recovery Efforts

Utility systems must maintain reliability to ensure a steady supply of energy to ride through times of peak demand or other constraints on the system. Such constraints are traditionally resolved by adding capacity to the transmission system from centralized generation units. When weather events impact the performance of the utility system, dispatchable capacity and system recovery at the distribution level become important to grid reliability.

Capacity Reserves

In traditional utility models, reserves are planned to meet capacity needs in excess of peak demand forecasts. Capacity reserves are deployed during times of high electric demand or when the transmission and/or distribution network becomes constrained for other reasons. Capacity reserves are established through targets, or reserve margin requirements, and fall near 15%[8] for the majority of electricity markets in the U.S. (EIA 2018b). Targets vary by region where demand load, generation capacity, and transmission and distribution characteristics are taken into consideration.

NERC entities—responsible for reliability oversight—often anticipate reserve margins well above the 15% target to meet unpredictable periods of high usage (i.e., during extreme heat waves). In some regions, anticipated reserve margins are high, achieving 30% or better (NERC 2018). Regions with high reserve margins might appear as having substantial generation capacity; however, the ability to achieve higher margins is also indicative of better resource use, such as deploying demand-side management and distributed energy resources onto the grid.

Even with an abundance of reserve capacity at-the-ready, weather-related events can result in unusually high levels of electricity demand and system failures. Some cases are extreme enough to diminish reserves, leading to blackouts. For instance, a heat wave in Southern

[8] A 15% reserve margin means that 15% of a region's electric generating capacity would be available as a buffer to meet the forecasted peak hourly load in the case of unusually high demand.

California in 2016 increased peak demand by 50% and, incidentally, 5,300 households lost power for several hours (Serna 2016).

Capacity Recovery

Utility system performance decreases almost immediately following the onset of a disruption or “shock” to the system, at which time emergency recovery efforts are deployed (by the utility or ISO/RTO). Available capacity resources are dispatched onto the grid (in ascended energy cost order) in an attempt to recover service interruptions. In many cases, large power stations—peaker plants—solely provide the recovery effort. Recent studies suggest that energy storage shows promise in black start[9] capability and other grid ancillary services (RMI 2015).

The availability of recovery resources, as well as the duration of the disruption, greatly impacts the success of emergency recovery efforts. For example, if reserve capacity or stored capacity is insufficient following a disruption, the decrease in system performance will likely be significant and noticeable across much of the customer base. Conversely, if resources are dispatched immediately following disruption and can meet real-time demand even under extreme circumstances, performance may be sustained, and the impact of the event would be small and, ideally, undetectable.

As an alternative to centralized capacity assets, states and utilities are looking to leverage distributed energy resources when responding to utility system constraints (EIA 2018a). Implementing DERs is becoming cost-competitive with that for adding/expanding centralized generation units. That said, renewable generation—wind and solar PV—can potentially exacerbate grid frequency and voltage stability problems, sometimes leading to curtailment themselves (ABB 2019). Energy storage is a promising solution for capturing and storing excess or “free” generation from renewable sources.

During blackouts and brownouts, dispatchable power from battery storage systems can provide recovery efforts to serve affected communities. Community-level recovery can be done through small-scale—or direct-connected systems[10]—where placed at key locations and distributed across the utility’s distribution grid. Stored capacity from batteries is not indefinite; the duration of power supplied is dependent upon the battery’s rated capacity and uptime[11]. The length of recovery during an outage can be extended where storage systems are recharged by renewable sources of generation.

The benefit of capacity recovery from storage assets compares to the value of uninterrupted power supply provided by centralized fossil fuel units. Where the benefits of DERs are combined to improve grid reliability while minimizing utility costs, they inherently enhance utility services and function as recovery efforts. These relationships are defined in Table 2 on the following page.

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[9] the procedure system operators use to restore power in the event of a total or partial shutdown, where power stations connect to the grid gradually and independently to re-energize the grid (National Grid ESO 2019).
[10] direct-connected storage is located in front of the meter and connected directly to a distribution system.
[11] length of charge before recharge needed.

Table 2. DERs and Grid Services

Type	Description	Resiliency/recovery benefit
Avoided Energy Costs	Represent the value of deploying DERs to avoid generation or the purchase of electricity from traditional sources. The marginal cost of avoided energy will vary considerably depending on the load shape and real-time demand for electricity.	Avoided energy costs are met by supplying electricity from distributed energy resources having zero production costs, such as standalone storage or solar PV plus storage. Avoided energy costs are directly related the amount of generation provided by DERs during a weather event or outage. Energy costs can be comparable to peak demand costs applied when electricity supply is constrained during times of high usage.
Avoided Capacity Costs	DERs can reduce the amount of capital invested in generating capacity from conventional sources, namely peaker plants. The magnitude and type of the reduction will vary according to the utility system, region served, and the capacity (MW) of the DERs deployed.	Dispatchable DERs eliminate the need for peaker plants when supply is constrained during weather-related events. Additionally, they may avoid the overestimation/premature construction of new generation units needed to account for the unpredictability of weather-related events and assumed outages.
Avoided Reserves	Reserves are deployed when a disruption in electricity supply occurs on the grid. Just as DERs can reduce the amount of generating capacity required from conventional resources, they can similarly reduce the amount of reserves dispatched onto the grid.	DERs can provide alternative electricity capacity when grid supply is constrained. DERs permit localized supply to areas experiencing grid outages. They can be placed on the distribution network at points of high vulnerability and low reliability. The value of avoided reserves can be included in avoided capacity cost estimates.
Avoided Transmission and Distribution Costs	DERs can reduce T&D loads and defer investments in infrastructure upgrades. Dispatched during peak demand times, they assist grid reliability issues, i.e., voltage regulation and frequency stabilization. Interest in the value of avoided distribution costs with DERs is gaining ground. Depending on the specific location of DERs on the electric grid, the value of avoided distribution costs could become significant.	As DERs become increasingly used to avoid distribution costs, the location-based value of avoided distribution costs will becoming strategically important for resource planners. Adding more DERs on the grid to avoid T&D costs can also result in greater grid resiliency, as DERs double as recovery efforts during power outages.
Enhanced Ancillary Service	Services required to maintain electric grid stability and reliability are *ancillary*. They include frequency and voltage regulation, spinning and non-spinning reserves, and demand reduction, among others.	DERs, such as energy storage, can serve as many ancillary services making storage cost-competitive, esp. where services are “stacked” to serve multiple functions on the grid.
Increased Reliability	In general, DERs are a viable partner in achieving electricity system reliability. As described in this table, integrating DERs onto the grid can readily assist during service interruptions.	The value of grid-integrated DERs will vary when it comes to weather-related events, with less value to systems that have undergone grid hardening efforts and more value to less resilient systems.

System Benefits

This study suggests that distributed energy resources pose unique benefits to utility services, especially at times when the grid is impacted by weather events. Distributed energy storage systems can be placed on the grid near high vulnerable locations, such as at critical facilities (e.g., hospitals, public water and sewer plants) and in densely populated areas. To maintain adequate capacity during long power outages, storage systems can be recharged by renewable generation systems, such as solar PV.

> Microgrids allow end users (e.g., households, businesses, hospitals, universities, industries, etc.) to generate and consume energy locally through the use of distributed generation and energy storage. A microgrid can bypass grid disruptions by functioning independent of the grid as an "electrical island" (DOE 2014).

Grid-connected storage systems improve the reliability and resiliency of the grid by providing backup supply[12] to customers during periods of excess demand or disruptions on the grid; stored capacity is quickly dispatched to provide a source of uninterrupted power supply.[13] For example, dispatching stored energy at the transmission level can help maintain grid reliability and provide black start service. On the distribution side, small-scale storage systems located downstream in communities provide backup power during outages (Brattle Group 2015).

Utilities and states across the U.S. are exploring storage options to supplement grid services. The following list below provides some project examples:

1. The utility, Oncor, has installed 25kW/25-kWh batteries in six South Dallas neighborhoods to provide up to 3 hours of backup power during grid outages (Cameron 2014).
2. The Long Island Power Authority (LIPA) has committed to installing 2.5MW of new utility-scale battery storage between 2019 and 2022 to serve as additional load capacity to assist black start services and defer distribution system investments (PSEG 2018).
3. The Arizona utility, Salt River Project, is investing in solar PV plus storage systems to provide 650MW of new peak capacity to meet increasing demand forecasts in 2022-2025 (APPA 2018).
4. The state of Maryland recently passed bill HB 650, establishing a statewide energy storage pilot program.[14] Pilot projects will launch in early 2022 and run through 2026. The bill applies to Maryland's four investor-owned utilities: Potomac Edison; Baltimore Gas and Electric; Delmarva Power and Light; and Potomac Electric Power (Mai 2019).
5. In May 2017, the California Public Utilities Commission enacted Assembly Bill 2868, ordering investor-owned utilities to procure up to an additional 500MW of energy storage, of which at least 375MW must be located on the distribution network ahead of the customer meter. The bill excludes transmission-connected systems (K&L Gates 2017).

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[12] Capacity when reserves are depleted; storage resources that pick up the load within 10 minutes (ESA 2019).
[13] Depending on the duration of a specific event, service interruptions may still occur as some outages may last longer than what can be covered by the storage.
[14] Through the pilot program, Maryland aims to understand the full benefits of energy storage, including its role in electric power markets. The program will assist state regulators in reform strategies and market incentives to increase the use of energy storage technologies and determine how best to integrate storage with the grid (Mai 2019).

6. Southern California Edison (SCE) will add 100MW of battery storage, along with smaller units (10 to 40MW), across its territory for flexible capacity. This system will tie for the world's largest battery storage and is planned to come online in December 2020. It nixes SCE's original plan to construct a new 262MW natural-gas peaker plant (Spector 2019).
7. Other states of interest: Oregon passed a law for 10-MWh of storage energy capacity by 2020 to be met by two electric utilities operating in the state; the Massachusetts Department of Energy Resources also set an energy storage target for 2020 of 200-MWh; New York has a target of 1.5GW of energy storage by 2025; lastly, several states now allow storage systems to be included in renewable portfolio standards (EIA 2018a).

Recovery Costs

A utility system that is resilient is defined as one having low to no impact costs (e.g., physical damage costs, loss of good and services) from severe weather events, e.g., hurricanes, tropical storms, and temperature extremes. Impact costs can include physical damage to infrastructure and economic losses due to diminished access to goods and services. Capital resources are required upfront to ensure that the utility system can maintain electricity service in the wake of an event.

Recovery costs are associated with recovery efforts during power outages, which commonly involves dispatching backup power from centralized reserves or distributed storage onto the grid. Insufficient and diminishing capacity during brownouts and blackouts decreases system performance and electric service reliability, which ultimately results in lost revenues for the utility. Customers could end up footing the bill for weather-related events should the utility be permitted to raise retail rates not only after events have occurred, but possibly *before* forecasted weather events. Event-related expenses imposed on customers are another type of recovery cost.

Some analysts use the Value of Lost Load (VoLL)[15] when estimating the cost of power outages to customers. In other words, it is the value of uninterrupted power supply from the customer's perspective, in $ per MWh (IEEE 2013). VoLL attempts to capture the customer's overall reliance on the grid, and is often seen as a customer's 'willingness to accept' and 'willingness to pay' to "keep the lights on". The rationale for VoLL is that customers are more willing to pay for uninterruptible power supply, even at high prices, and less tolerant of going without it.

One compiled study finds wide ranges in VoLL, from $10,000/MWh - $80,000/MWh for commercial and industrial customers and $1,000 - $5,000/MWh for residential customers (Brattle Group 2015). They seem to reflect varying customer preferences and do not provide a convincing average for valuing reliability (Keay 2016). Exceptionally high values are likely due to how VoLL is obtained: VoLL is estimated using customer survey information, where customers affected by outages are surveyed immediately following the event. The post-outage timing more than likely captures negative sentiments. For example, residential customers coming right out of an outage might exaggerate the value of temporary and personal inconveniences. High VoLLs in the commercial and industrial sector could more closely reflect true business-related losses.

[15] A measure of the value end users place on having a reliable and uninterrupted supply of electricity.

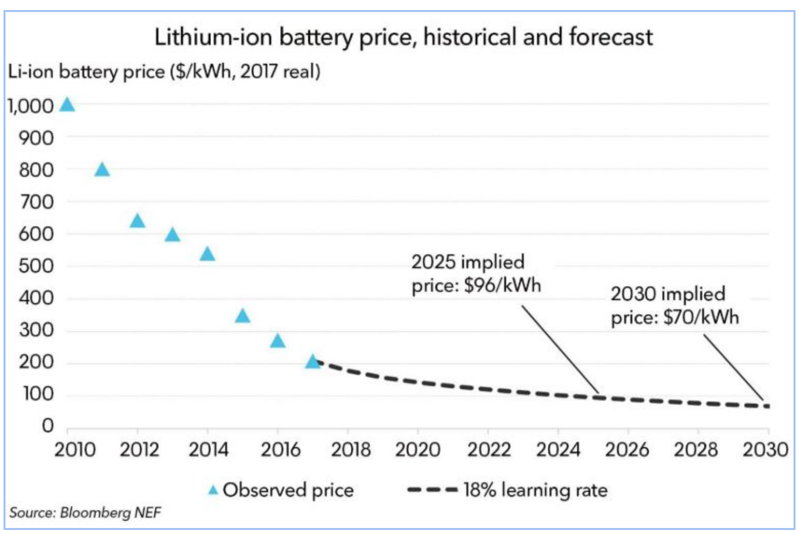
We know that risk assessments lack definitive pricing to quantify the costs of hypothetical future events. Economic theory would price a power outage at the cost of the best available alternative. If the utility lacks the means to provide backup power, customers will look to purchase grid-independent assets—generators, behind-the-meter battery storage, small-scale solar PV or wind turbines—to establish microgrids.

Up until just few years ago, alternative sources of energy were not-yet-scalable and cost-prohibitive. R&D-driven commercialization have lowered the costs of distributed generation and storage systems, and even fuel cells (ELP 2017). Decreasing costs have led to increased adoption rates.

Battery Technology

Recent growth in utility-scale photovoltaic (PV) deployment and recent declines in energy storage costs combine to create a cost-competitive pairing. Utilities integrate standalone storage units as well as PV plus storage to support both grid reliability and additional capacity needs.[16] Storage works as the "middleman" between the PV system to the grid, storing excess PV-generated capacity during low demand times and discharging electricity onto the grid during high times (NREL 2018).

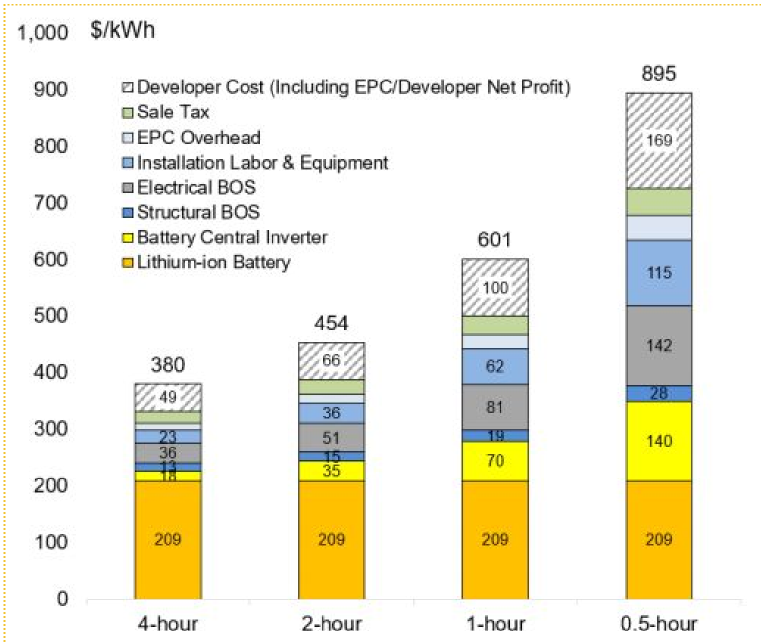
The feasibility of storage in utility applications piggybacks on the success of the electric vehicle industry. R&D in Lithium-ion battery technology has led to increasing production efficiencies and declining costs. For instance, battery prices fell 79% to $210/kWh over the recent seven-year period (2010-2017). Similarly, NREL (2018) benchmarks the price of Li-ion storage batteries at $209/kWh. By 2025 and 2030, battery costs are projected to fall to $96/kWh and $70/kWh, respectively (Bloomberg NEF 2018).



Current and projected Li-ion battery costs, 2010-2030. *Source*: Bloomberg NEF 2018.

[16] An important note about utility-scale PV systems is the required land area—averaging 6 to 9 acres per MWac, depending on PV technology deployed (NREL 2013).

Whole-system storage costs are captured to include non-battery costs, like that for auxiliary equipment and intangibles. Batteries with longer uptimes prove more cost-effective when evaluated at the whole-system level, as the non-battery costs become proportionally higher in systems with shorter uptimes. As depicted below, storage system costs vary from $380/kWh for 4-hour systems, up to $895/kWh for ½-hour systems (NREL 2018).



Battery storage system costs, for four uptime scenarios. *Source*: NREL 2018.

There may be instances where energy storage is unable to eliminate service interruptions completely, due to any number of physical or environmental characteristics.[17] For example, a power outage may last longer than the rated uptime of the batteries. Other reasons include a lack of redundancy or poor placement of storage units on the grid.

Storage is an effective distribution asset for utilities and customers to rely on when recovering from weather-related events. Communities can receive uninterrupted power supply during outages by locating direct-connected systems at strategic locations downstream. When equipped with off-grid charging capability, e.g., from co-located PV, direct-connected systems can potentially serve longer outages. For instance, the DTE Electric Company in Michigan installed 18 25-kW/50-kWh direct-connect storage units, supported by 500-kW of PV.

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[17] Electricity output and reliability for any given energy system is dependent on the system's availability and capacity factors, uptime, and generation source for recharge. Other factors include location, weather, and market prices.

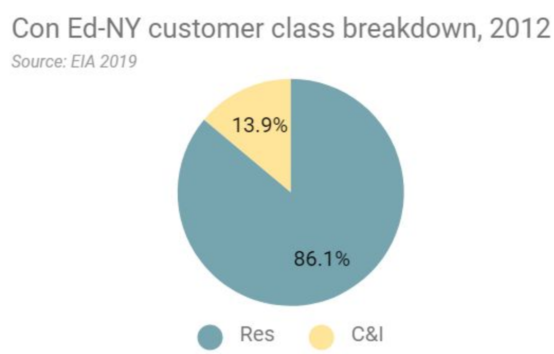
Con Ed of New York Case Study

Background

In late October 2012, the landfall of Hurricane Sandy caused several power outages in the eastern United States. One of the longest outages belonged to Consolidated Edison of New York (Con Ed-NY). The outage, originating from a transformer failure due to flooding, lasted 243 hours, the equivalent of 10 days, and impacted more than 800,000 customers in New York City (Riddell 2013).

Con Ed-NY's service territory is compact, covering only 604 sq. miles, with over 2.5 million customers; the residential sector comprises 86% of the customer base at approx. 2.1 million customers (EIA 2019). 70-75% of the utility's distribution power lines and 43 thousand transformers are buried underground. The IOU's remaining 52,000 transformers are located above ground in one of 62 substations (Con Ed 2019a).

Con Ed-NY service territory (in blue). *Source*: Con Ed 2012



Flood Resistant Substations

To prevent damage from a hurricane or tropical storm, one could advocate for constructing flood walls around substations or raising substations to protect transformers[18] from floodwater. Industry experts like the Energy Networks Association (ENA 2018) recommend for major electricity assets (i.e., transmission and distribution substations) to be resilient against 1,000-year flood[19] levels.

Thacker et al. (2018) found that direct damages from a single flood event averages $5 million per substation. Furthermore, they assume that when major substations fail, the outage affects at least three times as many people indirectly (i.e., via economic flow losses) than those individuals directly

[18] In an electric substation, the transformer is the single most expensive asset.

[19] "1,000-year flood" means that, statistically speaking, a flood of that magnitude (or greater) has a 1 in 1,000 chance of occurring in any given year. In terms of probability, the 1,000-year flood has a 0.1% chance of happening in any given year (USGS 2019).

served by the grid. A benefit-cost analysis for raising substations shows a positive NPV for outages lasting at least 2½ days; for shorter outages of less than 2½ days, flood walls prove most cost-effective (Thacker et al. 2018).

Evaluating Storage for Recovery

Investment decisions targeting grid reliability can use characteristic values from historic flood events and apply them to future floods having high probability for recurrence. One simple method recounts the duration (i.e., time period) of a past outage, the number of service interruptions/customers affected, and typical daily consumption rates (in kWh) to determine the recovery capacity needed during outages. When hurricanes and associated floods result in power outages, stored capacity can be deployed onto the grid at the community-level using small-scale, or direct-connected, storage systems.

Con Ed of NY vs. Hurricane Sandy

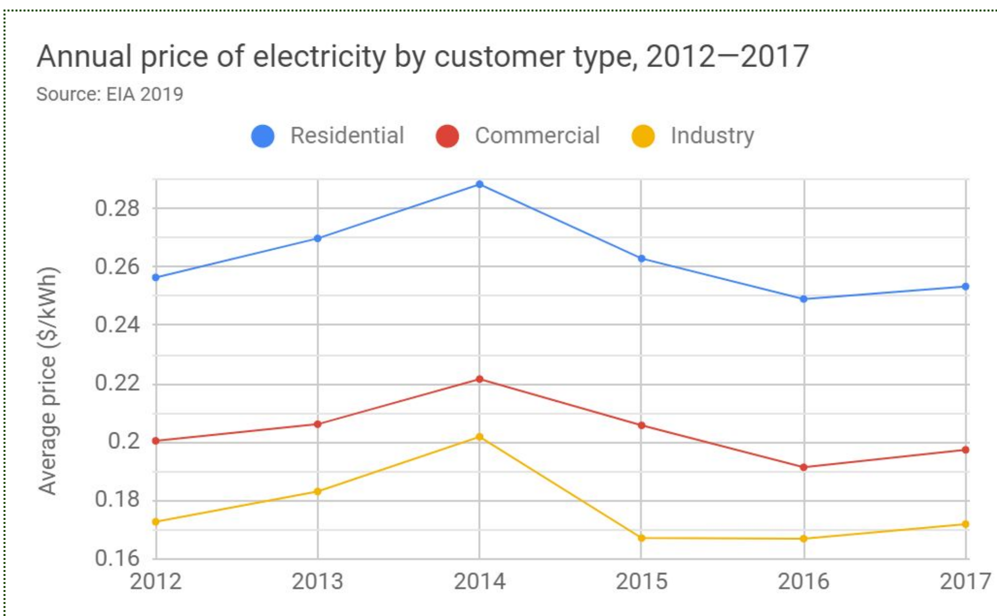
Outage stats

- Oct. 22-Nov. 2, 2012; 243 hours (~10 days).
- 818,000 customers affected; assume 86% residential and 14% C&I based on Con Ed-NY's customer class profile.

Con Ed-NY market stats

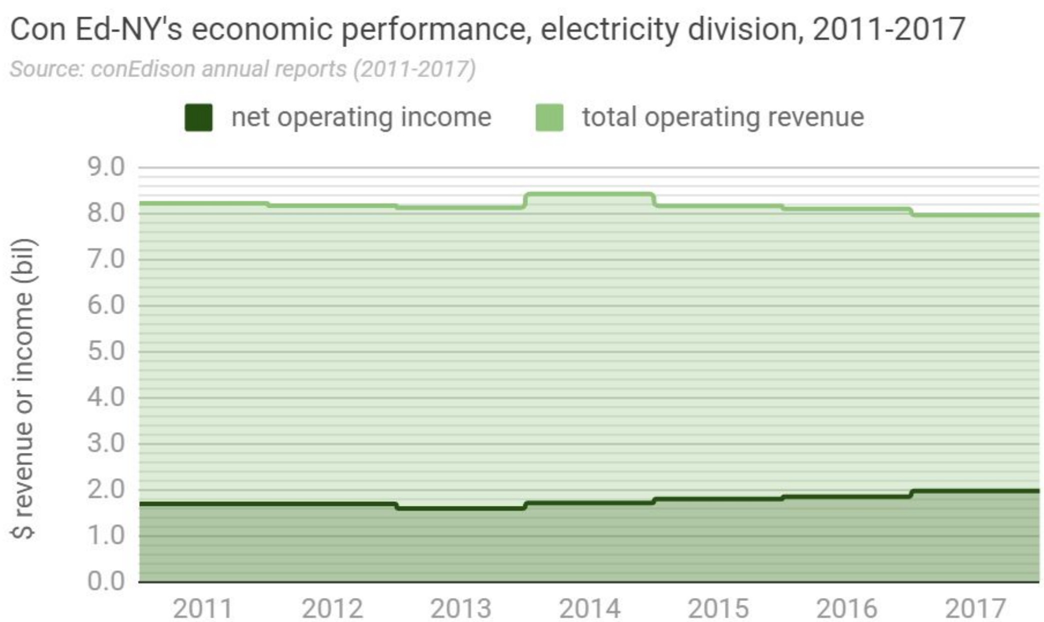
- Average electricity price in 2012 by customer class: 25.65 cents/kWh (res), 20.04 cents/kWh (comm), 17.94 cents/kWh (industrial).
- Retail electric sales and revenues in 2012 were approx. 20.6 MWh and $4.7 billion.

Con Ed-NY spent more than $1 billion on repairs and upgrades since Hurricane Sandy. Subsequently, the average price of electricity for the three main customer classes—residential, commercial, industrial—increased in the 2-year period following the storm, due to an approved rate case petitioned by the IOU. Electricity prices peaked in 2014.



The $1 billion spent on post-Sandy upgrades included the construction of three miles of flood walls at substations. Money was also spent installing automated switches and waterproofing electrical components. Despite these efforts, in early 2018, winter storm Riley created additional power outages, impacting approximately 70,000 of Con Ed-NY customers.

The chart below shows that Con Ed-NY's operating income fell in the immediate year following Hurricane Sandy, but the loss was recouped in 2014. The graph also shows that the IOU's operating revenue is gradually trending downward while net operating income is rising. The retail sales data presented in the table below proves higher electricity rates in 2013-2014 permitted increases in revenues, resulting in a 2-year net gain of $374 million for the utility (Con Ed 2019b).



	Electric retail sales ($)			Electric retail sales (MWh)		
Customer class	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2012**	**FY 2013**	**FY 2014**
Residential	2,748,928,000	2,773,035,000	2,847,226,000	10,717,525	10,273,410	9,869,409
C&I	1,981,262,000	2,026,081,000	2,188,259,000	9,901,704	9,842,688	9,885,964
Total	**4,730,190,000**	**4,799,116,000**	**5,035,485,000**	**20,619,229**	**20,116,098**	**19,755,373**
	$ increase over 2012	**$68,926,000**	**$305,295,000**	**% retail sales diff. from 2012**	-2.44%	-4.19%
		Net gain 2013-2014	**$374,221,000**			

Based on the most recent reported EIA data, daily average electricity usage for Con Ed-NY residential and commercial customers is 13 kWh and 72 kWh, respectively. Co Ed-NY's 67 industrial customers use significantly more electricity at 2443 kWh/day. For the sake of this analysis, we assume all industrial customers were either outfitted with backup power during Hurricane Sandy or have since made the investment.

To ensure recovery capacity during outages, a utility might invest in direct-connected storage systems to serve communities downstream. Using NREL's cost estimate of $380/kWh for 4-hour battery storage, costs are determined for Con Ed-NY residential and commercial customers. In order to maximize the amount of customers served, we propose that stored capacity is rationed for use only during the peak time of the day: 4 hours for residential and 8 hours for commercial to cover standard business hours. We assume 50% of the daily electricity use is consumed during peak periods for residential customers and 100% for commercial.

Costs for stored capacity and lost revenue, based on peak electricity use

Customer type	Daily peak usage kWh/cust/day	Daily storage costs @ $380/kWh, 4-hr uptime ($/cust)	Daily peak electricity costs, based on 2012 rates ($/cust)	# of customers affected in the 2012 power outage	Total lost revenue/cost of interruption to the utility from 10-day outage ($)
Residential	6.5 kWh	$380*6.5= $2,470	0.26*6.5= $1.69	703,480	1.69*10*703,480= $11.9 million
Commercial	72 kWh	$380(2)*72= $54,720	0.20*72= $14.40	114,520	14.40*10*114,520= $16.5 million

From this analysis, we find that the costs of electricity storage are exceptionally high compared to grid-supplied electricity under normal (non-stress) conditions. Hurricane Sandy in 2012 left 818,000 Con Ed-NY customers without power for 10 days. Based on the IOU's customer class profile, we assume 86% of those affected were residential customers and 14% were commercial. We extrapolate the data to conclude that the 10-day interruption cost Con Ed-NY $28.4 million in lost sales revenue.

Providing peak demand to 100% of customers affected by Hurricane Sandy with direct-connected storage would run $48 billion in upfront storage costs (see table below). The recharge capability unique to storage assets makes them potentially cost-effective when additional capacity is generated from off-grid resources (i.e., solar PV), having minimal to no production costs. Additionally, storage supported by PV appeal to longer outages, since recharging is done independent of the grid.

Recovery costs for Hurricane Sandy power outage using distributed storage

Customer type	Peak kWh/cust	# of customers affected in 2012 power outage	10-day stored capacity required, covering 100% customers affected	Total storage costs @ $380/kWh ($)
Residential	6.5	703,480	45.7 GWh	$17 billion
Commercial	72	114,520	82.5 GWh	$31 billion

Recharging distributed storage systems becomes vital to providing power to communities during prolonged outages, such as "Sandy-size" events. However, the feasibility for recharging storage systems—whether by conventional or renewable sources—depends on the severity of the weather event at hand. Damaged grid infrastructure can limit conventional generation from reaching direct-connected storage and PV becomes unreliable under persistent overcast skies.

Con Ed-NY's dense service area likely presents a challenge for large, non-transmission PV+storage systems. Utility-scale PV arrays require open land (e.g., 4 acres per 100 MW), where area and generation capacity are proportionally-related. Grid resiliency efforts in land-constrained service territories should target distributed storage assets or substation hardening (i.e., raising substations, constructing flood walls), or a combination of these two measures.

Hardening Con Ed-NY's 62 substations might make better use of capital resources for ensuring systemwide reliability in the face of weather-related events. In a one-to-one comparison, substations serve more customers than direct-connected storage systems. Where substations have been hardened against floods, customers are likely to continue receiving power from the grid even during severe storms, such as super storms and hurricanes.

The costs to construct flood walls and raise substations can vary widely; hardening costs take into account substation size and site characteristics. An effective hardening program would first assess and prioritize the vulnerability of each substation before assigning measures and allocating capital. Capital dollars earned through retail rate increases—Con Ed-NY's $374 million net gain in 2013-2014, for example—should go toward investments in permanent resilience measures with long lifespans (e.g., 30-40 years).

Net sales example
Using Con Ed-NY's $374 million in nets gains as a base reference, $5.8 million could be allocated to each of Con Ed-NY's 62 substations to pay for hardening projects. This investment amount is on par with damage cost estimates at substations due to flooding (Thacker et al. 2018). This example does not intend to advocate for electricity rate increases. Rather, the goal is to establish *permanent* grid reliability solutions that have the biggest *benefit* across the *customer* base. Customers should not be subjected to rate increases year-over-year to pay for vulnerable utility assets and regulators must take this into consideration when evaluating rate cases.

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Results

Grid hardening measures and energy storage assets can support the grid during extreme weather events. Grid hardening measures are preventative in the sense that they eliminate power outages and lessen infrastructure damage. When outages do occur, energy storage from distributed systems replaces the reserve capacity traditionally provided by centralized generation units.

The unpredictability of weather events makes grid hardening measures more appealing from a cost-effective standpoint. On a per customer basis, hardening proves more cost-effective than recovery efforts—a single weatherproofed substation potentially serves more customers than one MWh of stored capacity. Without recharge capability, storage assets are cost-prohibitive for outages affecting large numbers of customers or outages lasting several days.

By eliminating future damage costs, the ROI for grid hardening measures is further improved in recurring weather events. Capacity recovery efforts are event-specific; additional capacity requirements are not uniform from one outage to the next. Not knowing the exact impact of future storms, it is difficult to identify the magnitude of future power outages and where to place storage assets of on the grid for maximum benefit, aside from at critical facilities.

Grid reliability establishes a *replacement cost* that storage can compete for, as it does with grid ancillary services. However, storage assets are expensive to deploy across entire grids, if the goal is to have enough stored capacity at-the-ready to serve all customers regardless of risk. Utility-scale PV plus storage systems require sufficient land area to accommodate large PV arrays since the generation capacity of the system is proportional to the surface area of the array. Thus, PV plus storage systems are challenging to distribute across space-constrained service territories.

As climate change continues to wreak havoc on vulnerable infrastructure, utilities and their customers will continue to be plagued by the damages left in the wake of severe storms and wildfires. Damage cost totals now account for more than direct damages to physical infrastructure. Increasingly, weather-related events cause widespread damage throughout communities, like that of the 2017-2018 wildfires in California. These fires resulted in millions of dollars in personal property damage and many lost lives. Eventually, litigation claims and other soft costs become too much for even large utility companies to absorb.

System-wide resilience is not achievable for utilities who cap one-time capital investments at $1 billion dollars or who parcel out resilience projects in small doses. Utility resource plans often target upgrading centralized generation units with more-efficient fossil fuels (i.e., natural gas) rather than investing in grid resilience. Lacking a resilient grid, customers typically foot the bill for post-event repairs and upgrades through higher electricity prices. Risk assessments could guide utilities in investment decisions by focusing on assets having the greatest risk of failure and customer impact. Two case studies presented in this report analyze the cost-benefit of undergrounding power lines located in high wind and fire-prone forests, deploying small-scale distributed storage systems, and floodproofing vulnerable substations.

The cost-effectiveness of resiliency measures increases when the indirect costs of damage are taken into account. We made the case for burying distribution lines in fire-prone areas by assigning PG&E’s indirect costs (e.g., litigation claims and bankruptcy costs) to direct damage costs. As droughts and wildfires are expected to continue in California, undergrounding power lines in fire-prone areas have a payback of 2-7 years. The benefit for undergrounding power lines is applied to future years, where today’s investments avoid the direct and indirect damages of recurring wildfires. Considering the average 30-40 year lifespan of utility system infrastructure and the likelihood of wildfire recurrence, a 2-7 year payback is encouraging.

We also show that lost revenue from prolonged power outages can cost a utility tens of millions of dollars. Raising electricity rates to pay for repairs essentially leave the customer footing the bill for weakened utility assets. Gains from rate increases should only be applied to permanent solutions that result in a more resilient and reliable grid.

Discussion

The longstanding method for managing the electric grid is done by evaluating utility system loads and dispatching generation to meet peak demand. Centralized generation has proven itself a reliable source of electricity, but blackouts and brownouts occur even in the most reliable systems. The increasing recurrence of disastrous events, like super storms and wildfires, quickly demonstrate that conventional approaches to grid reliability cannot overcome the unpredictable implications of weather-related events.

The utility sector (as with most other industries) prefers a cost measurement approach when allocating capital resources to improve grid reliability. However, raising electricity rate increases for disaster response should not be deemed a viable long-term financial solution. Cost-effectiveness tests are evolving beyond the utility's perspective where comprehensive approaches aim to assist regulators in rate-making decisions.

Some energy markets in the U.S. now employ integrated resource planning and capacity procurement to address potential future supply shortcomings. Forward capacity markets may prove promising in meeting resource needs when the grid is under stress from natural causes, just as demand response has shown in alleviating supply constraints during times of peak consumption. To date, forward capacity markets in the U.S. are challenging the limitations of earlier market designs, and DERs now compete directly with conventional supply-side power generation.

As energy storage becomes recognized for providing grid ancillary services, it is also being considered for recovery efforts following weather-related events. Recently enacted policies require utilities to diversify energy generation portfolios and integrate distributed energy resources to meet clean energy targets, renewable portfolio standards, and grid reliability standards. Some states and utilities are establishing pilot projects to demonstrate standalone storage and PV plus storage systems in utility-scale applications. Government-driven mandates hold the potential for showcasing the resiliency benefits of DERs in concert with carbon mitigation strategies.

The goal of risk assessments and cost-effective screening is to provide economists, urban planners, policymakers, and even regulators the information they need in developing long-lasting solutions for the number of issues facing society today. Quantifying the *more qualitative* attributes of DERs remains tricky, however. How we monetize damages is important in how we value resiliency strategies. The cost-effectiveness of resiliency measures takes into account both direct and indirect damage costs as well as the benefit of damage cost avoidance in recurring events. This framework can be used to compare the benefits of the avoided damage costs to the costs of modifying the utility system.

As we find new accounting methods to account for grid reliability, we come closer to knowing the value of grid hardening measures and recovery efforts when “weathering out” events. Grid reliability is becoming synonymous with resilience; a system that reliably maintains the demand-supply balance during extreme weather events stands *resilient*.

Conclusion

This study supports the effort that a number of recent studies have highlighted: climate change hazards present large impacts on infrastructure systems and the communities that rely on them. As local impacts are realized, it becomes clear that climate change imposes significant loss of personal property and livability in communities left unprepared and inept. The costs of recovery are near-impossible for some communities to bear on their own.

Community stakeholders are becoming more aware of the looming hazards of climate change—the unpredictability of weather-related events and their vulnerability to them. It is important for utility system owners and operators to step up and leverage capital resources to harden the grid against damages and develop alternative solutions for providing capacity during power outages.

As with any emerging and complex issue, the topic of grid resilience requires further research. Real-world demonstrations and pilot projects can help understand clearly the cost-benefit of grid reliability and enhanced utility services unique to DERs. Interdisciplinary studies can identify best-use cases for DERs—for both the utility and society—and can inform energy policy-making decisions. The 21st century energy landscape is evolving under the guise of a changing climate and we must ensure it supports the needs of generations to come.

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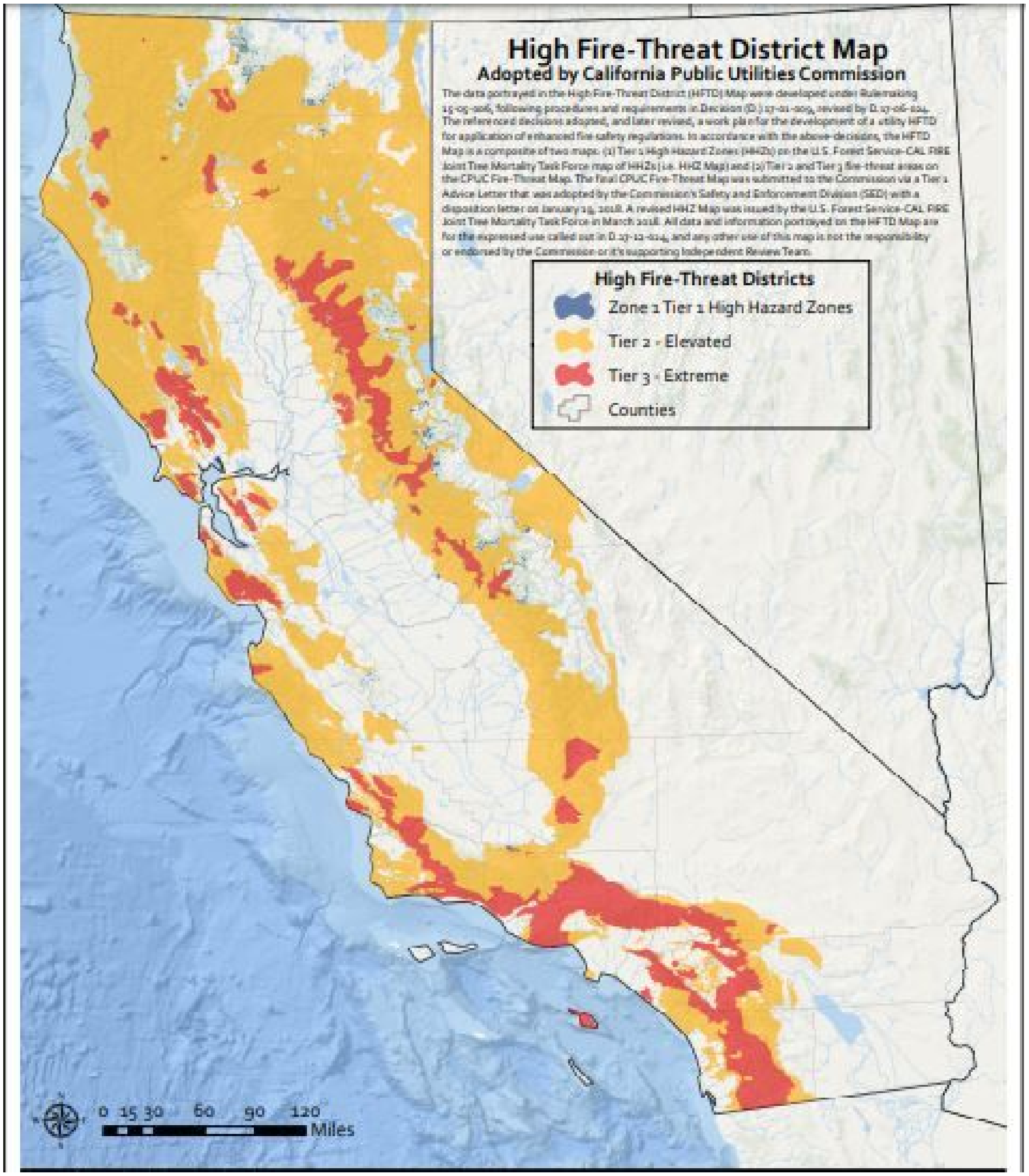
Appendix A. High-fire threat districts (HFTDs) in CA



Appendix B

NPV — PG&E Case Study

Year	1	2	3	4	5	6	7	8	9	10
benefits ($bil)	$13.61	$13.61	$13.61	$13.61	$13.61	$13.61	$13.61	$13.61	$13.61	$13.61
low, high	$14.51	$14.51	$14.51	$14.51	$14.51	$14.51	$14.51	$14.51	$14.51	$14.51
capital costs ($bil)	$25.20	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
low, high	$95.80	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ben-cost ($bil)	-$10.69	$13.61	$13.61	$13.61	$13.61	$13.61	$13.61	$13.61	$13.61	$13.61
best, worst	-$82.19	$13.61	$13.61	$13.61	$13.61	$13.61	$13.61	$13.61	$13.61	$13.61
disc. factor	1.03	1.06	1.09	1.12	1.15	1.18	1.21	1.24	1.27	1.30
disc. cash flow	-$10.38	$12.84	$12.48	12.15	11.83	11.53	11.24	10.97	10.71	10.47
best, worst	-$79.80	$12.84	$12.48	$12.15	$11.83	$11.53	$11.24	$10.97	$10.71	$10.47
NPV	-$10.38	$2.46	$14.94	$27.09	$38.92	$50.45	$61.70	$72.67	$83.38	$93.85
best, worst	-$79.80	-$66.96	-$54.48	-$42.33	-$30.50	-$18.97	-$7.73	$3.25	$13.96	$24.43

a) Benefits = avoided wildfire-related expenses, based on 2018-2019 costs.
b) 3% discount rate used.