Estimating the Value of Underground or Submarine Lines

Author (2015)

Haley and Aldrich (2022)

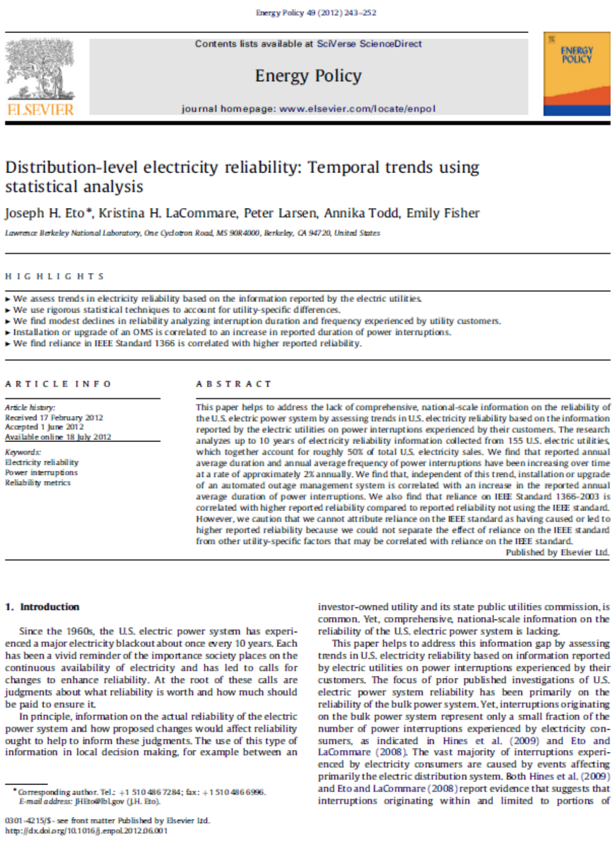
Peter Larsen

July 27, 2022 ▪ Isolated Power Systems Connect

BERKELEY LAB

Background

- Interest in undergrounding was a result of Berkeley Lab research into factors that impact long-term reliability of U.S. power system…



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Distribution-level electricity reliability: Temporal trends using statistical analysis

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HIGHLIGHTS

- ▸ We assess trends in electricity reliability based on the information reported by the electric utilities.
- ▸ We use rigorous statistical techniques to account for utility-specific differences.
- ▸ We find modest declines in reliability analyzing interruption duration and frequency experienced by utility customers.
- ▸ Installation or upgrade of an OMS is correlated to an increase in reported duration of power interruptions.
- ▸ We find reliance in IEEE Standard 1366 is correlated with higher reported reliability.

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ABSTRACT

This paper helps to address the lack of comprehensive, national-scale information on the reliability of the U.S. electric power system by assessing trends in U.S. electricity reliability based on the information reported by the electric utilities on power interruptions experienced by their customers. The research analyzes up to 10 years of electricity reliability information collected from 155 U.S. electric utilities, which together account for roughly 50% of total U.S. electricity sales. We find that reported annual average duration and annual average frequency of power interruptions have been increasing over time at a rate of approximately 2% annually. We find that, independent of this trend, installation or upgrade of an automated outage management system is correlated with an increase in the reported annual average duration of power interruptions. We also find that reliance on IEEE Standard 1366-2003 is correlated with higher reported reliability compared to reported reliability not using the IEEE standard. However, we caution that we cannot attribute reliance on the IEEE standard as having caused or led to higher reported reliability because we could not separate the effect of reliance on the IEEE standard from other utility-specific factors that may be correlated with reliance on the IEEE standard.

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1. Introduction

Since the 1960s, the U.S. electric power system has experienced a major electricity blackout about once every 10 years. Each has been a vivid reminder of the importance society places on the continuous availability of electricity and has led to calls for changes to enhance reliability. At the root of these calls are judgments about what reliability is worth and how much should be paid to ensure it.

In principle, information on the actual reliability of the electric power system and how proposed changes would affect reliability ought to help to inform these judgments. The use of this type of information in local decision making, for example between an investor-owned utility and its state public utilities commission, is common. Yet, comprehensive, national-scale information on the reliability of the U.S. electric power system is lacking.

This paper helps to address this information gap by assessing trends in U.S. electricity reliability based on information reported by electric utilities on power interruptions experienced by their customers. The focus of prior published investigations of U.S. electric power system reliability has been primarily on the reliability of the bulk power system. Yet, interruptions originating on the bulk power system represent only a small fraction of the number of power interruptions experienced by electricity consumers, as indicated in Hines et al. (2009) and Eto and LaCommare (2008). The vast majority of interruptions experienced by electricity consumers are caused by events affecting primarily the electric distribution system. Both Hines et al. (2009) and Eto and LaCommare (2008) report evidence that suggests that interruptions originating within and limited to portions of

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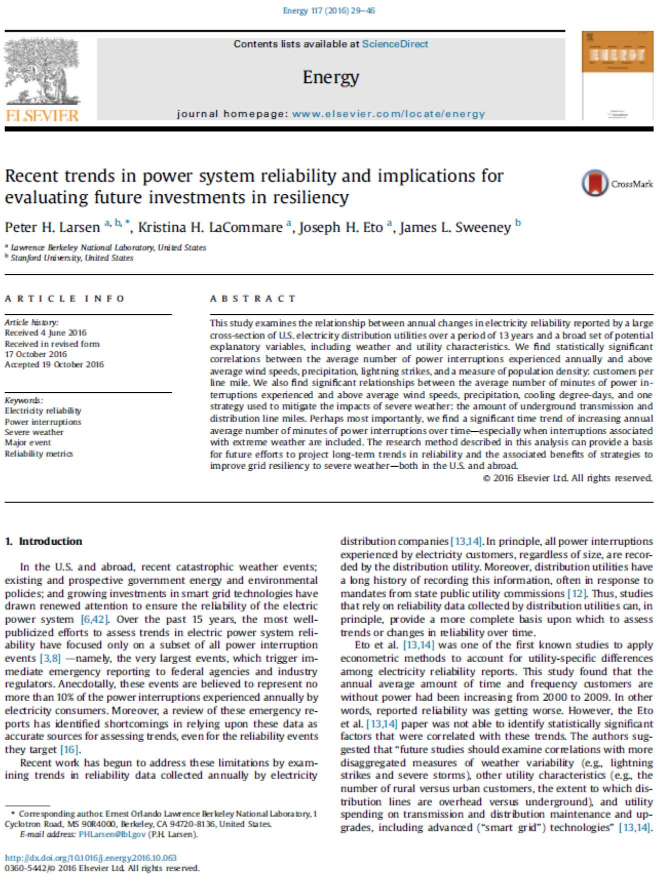

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Recent trends in power system reliability and implications for evaluating future investments in resiliency

CrossMark

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ABSTRACT

This study examines the relationship between annual changes in electricity reliability reported by a large cross-section of U.S. electricity distribution utilities over a period of 13 years and a broad set of potential explanatory variables, including weather and utility characteristics. We find statistically significant correlations between the average number of power interruptions experienced annually and above average wind speeds, precipitation, lightning strikes, and a measure of population density: customers per line mile. We also find significant relationships between the average number of minutes of power interruptions experienced and above average wind speeds, precipitation, cooling degree-days, and one strategy used to mitigate the impacts of severe weather: the amount of underground transmission and distribution line miles. Perhaps most importantly, we find a significant time trend of increasing annual average number of minutes of power interruptions over time—especially when interruptions associated with extreme weather are included. The research method described in this analysis can provide a basis for future efforts to project long-term trends in reliability and the associated benefits of strategies to improve grid resiliency to severe weather—both in the U.S. and abroad.

1. Introduction

In the U.S. and abroad, recent catastrophic weather events; existing and prospective government energy and environmental policies; and growing investments in smart grid technologies have drawn renewed attention to ensure the reliability of the electric power system [6,42]. Over the past 15 years, the most well-publicized efforts to assess trends in electric power system reliability have focused only on a subset of all power interruption events [3,8] —namely, the very largest events, which trigger immediate emergency reporting to federal agencies and industry regulators. Anecdotally, these events are believed to represent no more than 10% of the power interruptions experienced annually by electricity consumers. Moreover, a review of these emergency reports has identified shortcomings in relying upon these data as accurate sources for assessing trends, even for the reliability events they target [16].

Recent work has begun to address these limitations by examining trends in reliability data collected annually by electricity distribution companies [13,14]. In principle, all power interruptions experienced by electricity customers, regardless of size, are recorded by the distribution utility. Moreover, distribution utilities have a long history of recording this information, often in response to mandates from state public utility commissions [12]. Thus, studies that rely on reliability data collected by distribution utilities can, in principle, provide a more complete basis upon which to assess trends or changes in reliability over time.

Eto et al. [13,14] was one of the first known studies to apply econometric methods to account for utility-specific differences among electricity reliability reports. This study found that the annual average amount of time and frequency customers are without power had been increasing from 2000 to 2009. In other words, reported reliability was getting worse. However, the Eto et al. [13,14] paper was not able to identify statistically significant factors that were correlated with these trends. The authors suggested that "future studies should examine correlations with more disaggregated measures of weather variability (e.g., lightning strikes and severe storms), other utility characteristics (e.g., the number of rural versus urban customers, the extent to which distribution lines are overhead versus underground), and utility spending on transmission and distribution maintenance and upgrades, including advanced ("smart grid") technologies" [13,14].

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- …increase in % share of T&D lines that are underground has a statistically significant correlation with improved reliability

Background (cont.)

- Despite the high costs attributed to power outages, there has been **little or no research to quantify both the benefits and costs of improving electric utility reliability/resilience**—especially within the context of decisions to underground T&D lines (e.g., EEI 2013; Nooij 2011; Brown 2009; Navrud et al. 2008)

- Brown (2009) found that the costs—in general—of undergrounding utility transmission and distribution (T&D) infrastructure were "far in excess of the quantifiable storm benefits"

- **Policies specifically targeting areas for undergrounding are cost-effective if a number of key criteria are met…**

Undergounding Analysis: Cordova, Alaska

Author (May 2015)

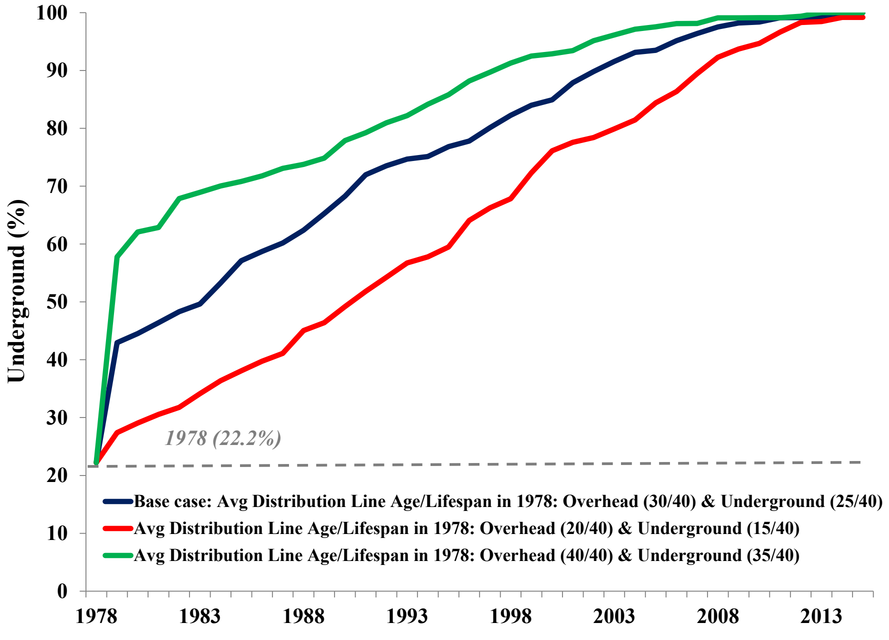
Analysis framework: Cordova case (cont.)

Key Stakeholders	1978 Decision to Underground 100% of Distribution System	
	Selected Costs	**Selected Benefits**
Cordova Electric Cooperative	• Increased chance of worker accidents*	
Cordova ratepayers	• Additional administrative, siting, and permitting costs associated with undergrounding* • Increased capital costs for undergrounding***	• Lower operations and maintenance costs for undergrounding* • Decreased ecosystem restoration/right-of-way costs*
All residents/businesses within service area		• Avoided societal costs due to less frequent power outages***** • Avoided aesthetic costs*** • Decreased chance of community fatalities and accidents[NA]

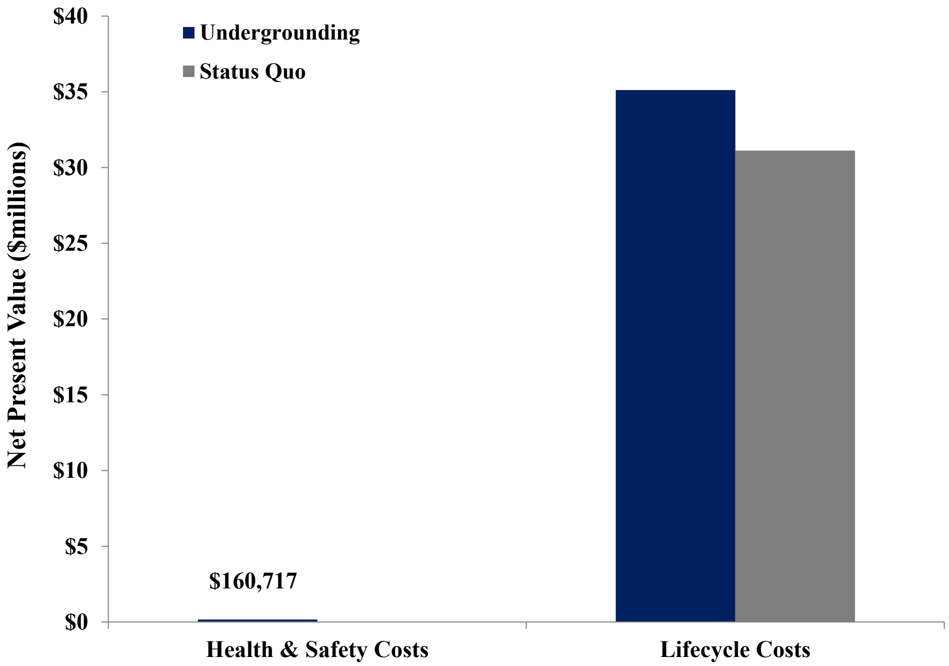
Key:

Minor impact on results → *** Major impact on results*

Estimated costs

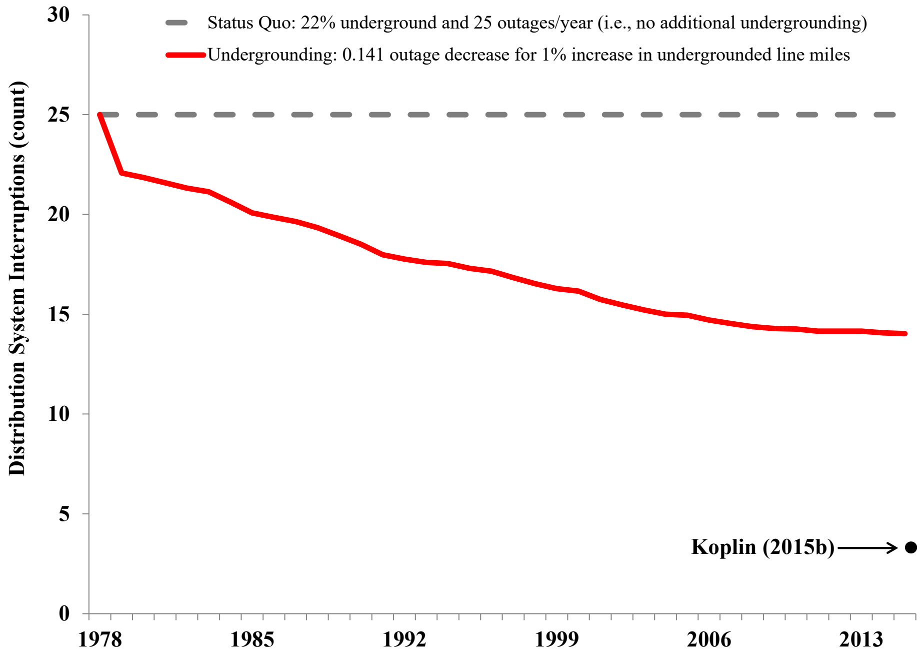


- NPV of undergrounding and status quo costs ($2015)

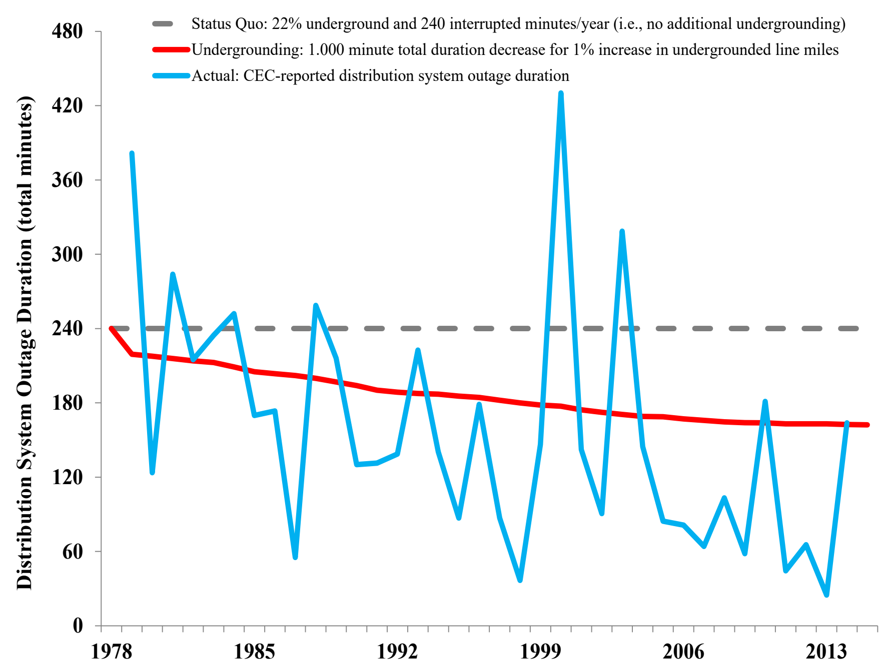


Estimated benefits

Customer interruptions



Interruption minutes

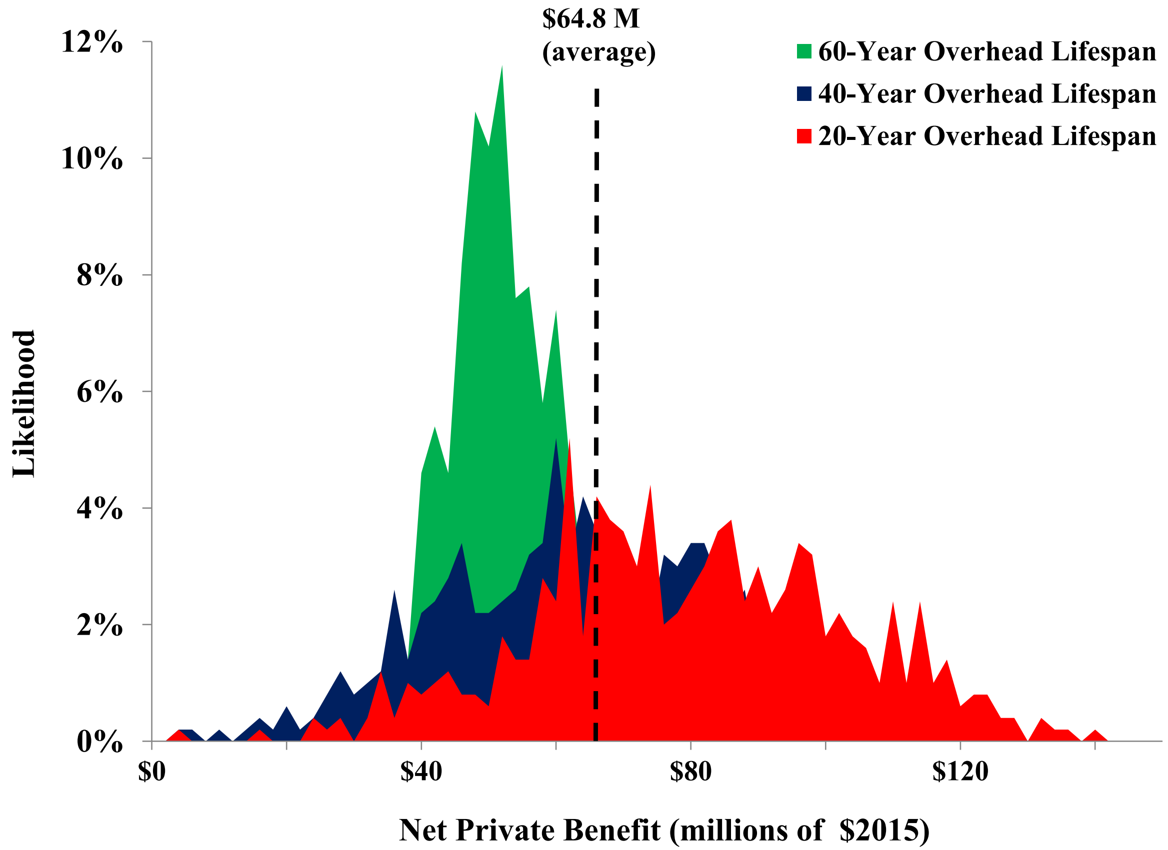


Net social benefit

Impact Category	100% Underground	Status Quo	Net Cost ($millions)
Health & safety costs	$0.2	$0	$0.2
Lifecycle costs	$35.3	$31.1	$4.1
Total net costs (Undergrounding)			$4.3
Impact Category	**100% Underground**	**Status Quo**	**Net Avoided Costs ($millions)**
Interruption costs	$130.1	$194.7	$64.6
Aesthetic costs	$27.9	$24.4	$3.5
Enviro. restoration costs	$2.4	$3.1	$0.6
Total net benefits (Undergrounding)			$68.7
Net Social Benefit (Undergrounding)			
Net social benefit (millions of $2015)			**$64.5**
Benefit-cost ratio			**16.1**

NOTE: **Reliability benefits, although large, are not necessary for cost-effectiveness**.

Sensitivity analysis



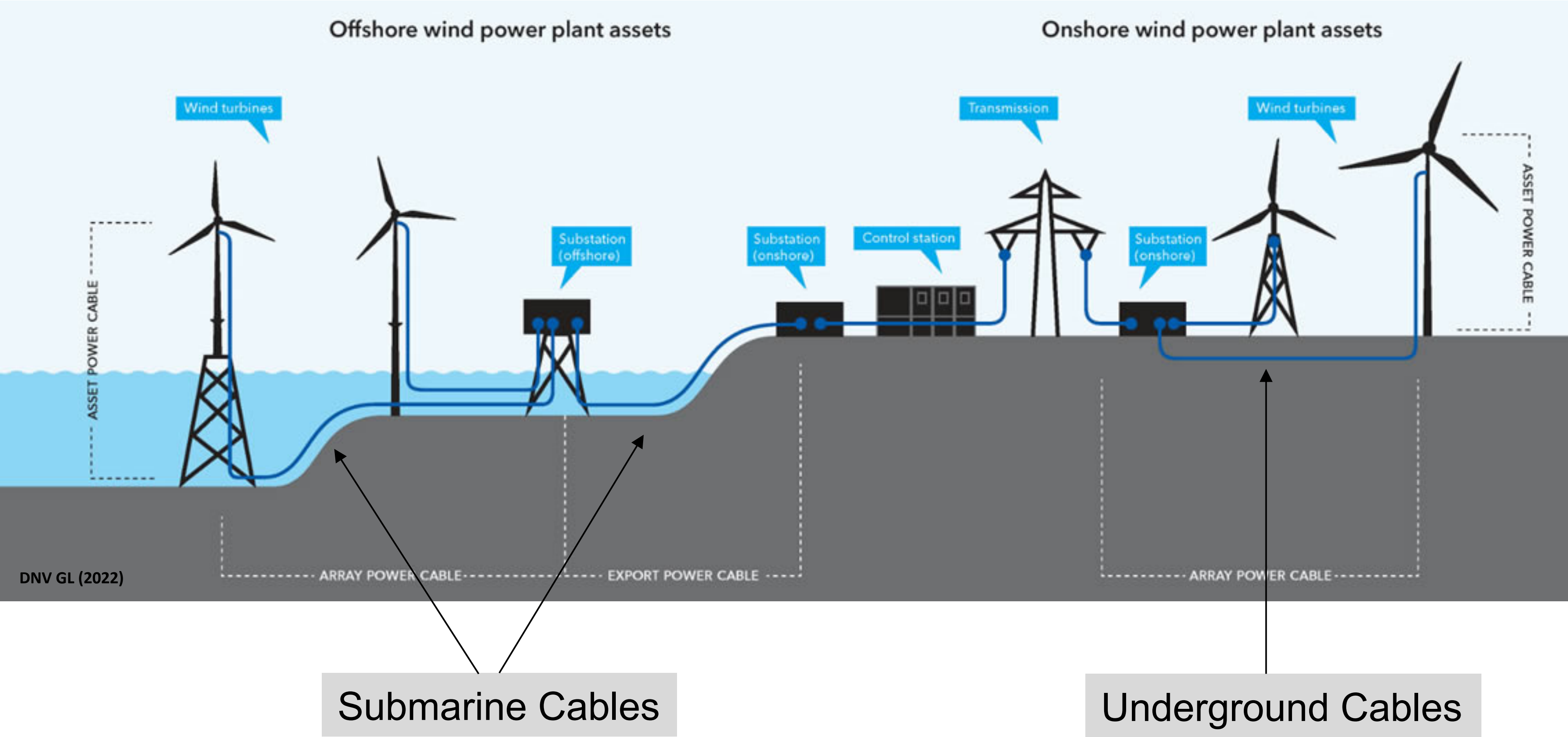
- A Monte-Carlo simulation was conducted by sampling all of the key input assumptions from uniform distributions—bounded by the minimum and maximum values reported earlier— simultaneously

- **Varying all of the key parameters simultaneously leads to consistently positive net benefits**

Conclusion on undergrounded lines

- Generally **assumed that the costs of undergrounding transmission and distribution lines far exceed the benefits** from avoided outages
- Undergrounding power system infrastructure can improve reliability and that comprehensive benefits of this strategy can, in some cases, exceed the all-in costs
- **Cost-effectiveness depends on (1) the age/lifespan of existing overhead infrastructure; (2) whether economies of scale can be achieved; (3) the vulnerability of locations to increasingly severe and frequent storms; and (4) the number of customers per line mile.**
- **Analysis framework could be adapted to evaluate economics of other strategies to improve grid resilience and reliability** (e.g., grid hardening activities)

Submarine transmission lines provide access to renewable energy resources and/or connect isolated communities

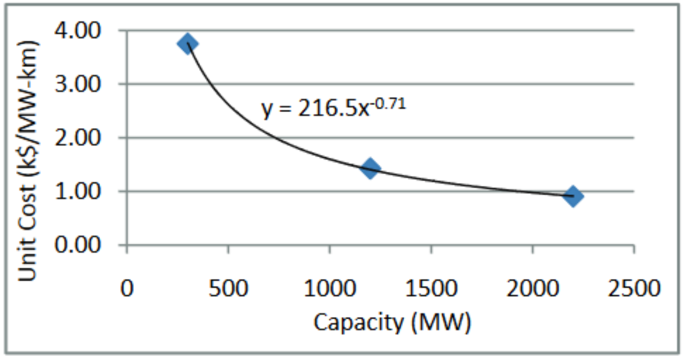


DNV GL (2022)

Examples of overhead and submarine transmission line costs

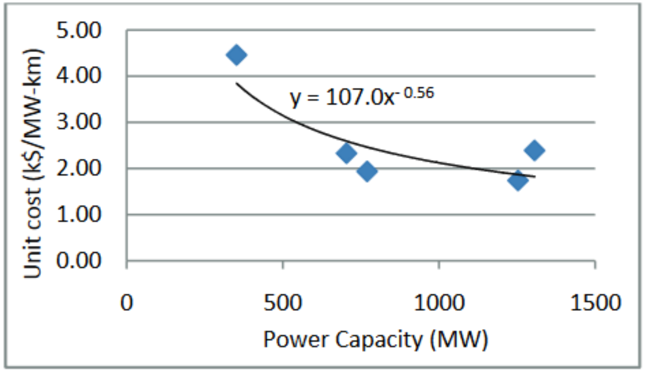
Overhead Transmission Lines

Voltage (Capacity)	Cost ($/mi)
345 kV (300 MW)	$1.8M
500 kV (1200 MW)	$2.7M
765 kV (2200 MW)	$3.2M



Submarine Transmission Lines

Voltage (Capacity)	System	Cost ($/mi)
150 kV (352 MW)	Bipole submarine	$2.5M
300 kV (704 MW)	Bipole submarine	$2.6M
300 kV (1306 MW)	Bipole submarine	$5.0M
300 kV (770 MW)	Bipole on-shore	$2.4M
300 kV (1253 MW)	Bipole on-shore	$3.5M



Adapted from Liun (2016); Actual costs may be higher or lower than these illustrative examples

Different value proposition for submarine lines

- Submarine lines, like underground lines, often cost more per line mile than overhead lines
- The primary benefit of undergrounding lines is the economic value of avoiding power disruptions
- Submarine lines also provide valuable reliability benefits, but there may be additional, significant value streams:
  - Avoided fossil fuel-related pollution
  - Islanded power system self-sufficiency

Shameless plug for new project…

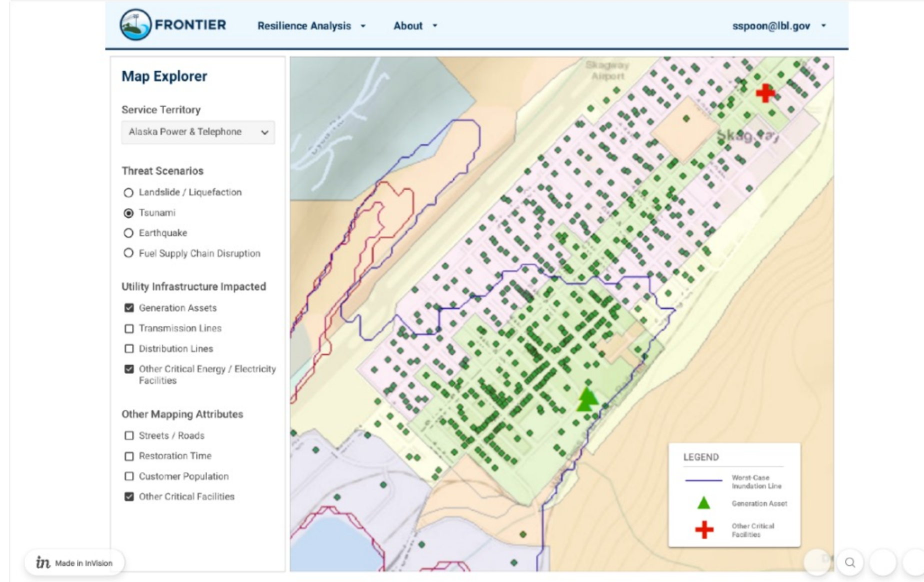
- Recent large-scale disasters on energy systems, including hurricanes in the Caribbean and flooding in Alaska, highlight the need to proactively minimize future risk to critical infrastructure.

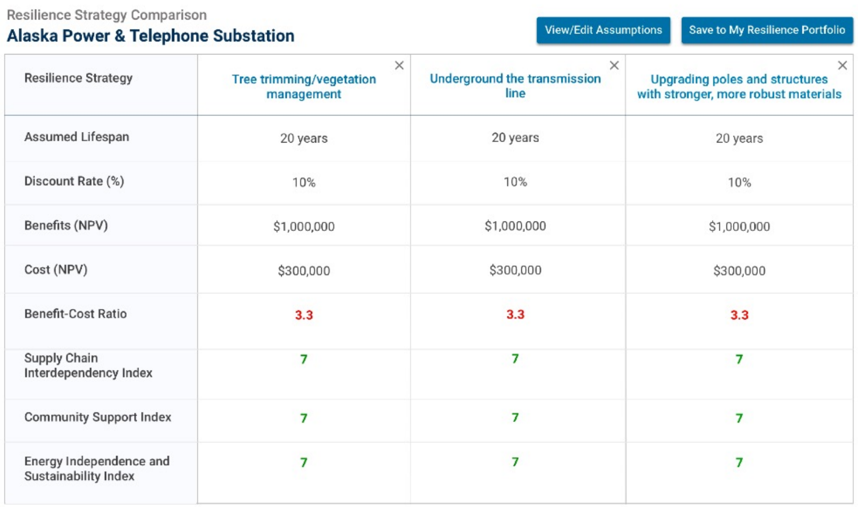
- States and territories express a need for technical assistance in improving energy system resilience in the face of evolving threats and hazards.

- **Officials are interested in having access to online decision support tools to assist utility planners and policymakers considering investments in power system reliability and resilience…**

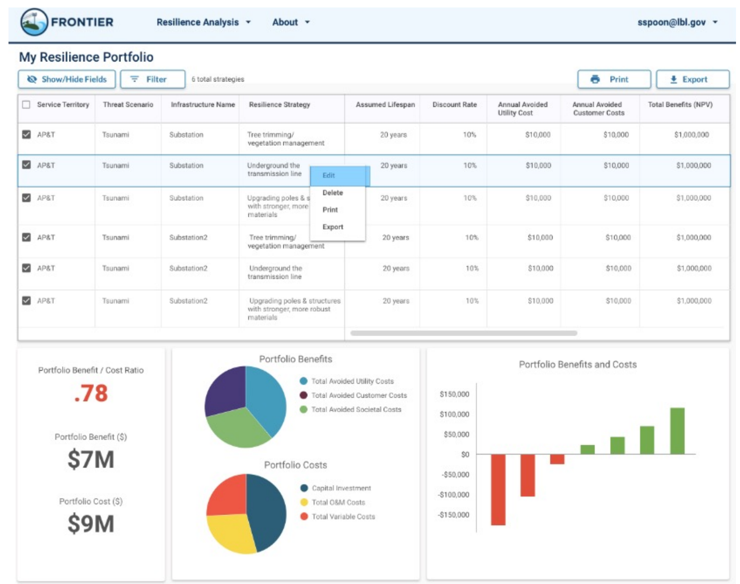
FRONTIER

Framework for Overcoming Natural Threats to Islanded Energy Resilience ("FRONTIER")





Resilience Strategy	Tree trimming/vegetation management	Underground the transmission line	Upgrading poles and structures with stronger, more robust materials
Assumed Lifespan	20 years	20 years	20 years
Discount Rate (%)	10%	10%	10%
Benefits (NPV)	$1,000,000	$1,000,000	$1,000,000
Cost (NPV)	$300,000	$300,000	$300,000
Benefit-Cost Ratio	3.3	3.3	3.3
Supply Chain Interdependency Index	7	7	7
Community Support Index	7	7	7
Energy Independence and Sustainability Index	7	7	7



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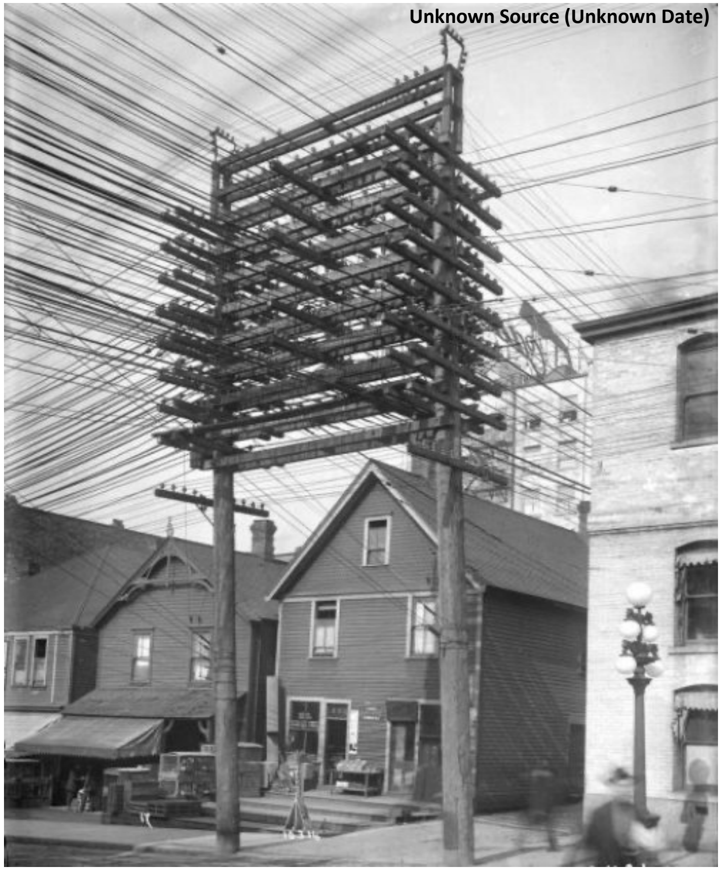

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Appendix

Analysis framework: Cordova case

- Study perspective:
  - CEO who cares about maximizing private benefits
- Key stakeholders with standing:
  - Cordova Electric Cooperative, ratepayers, and all residents within service territory
- Policy alternatives:

  (1) 1978 status quo (i.e., maintain existing underground and overhead line share)

  (2) Underground all T&D lines (i.e., underground when existing overhead lines reach end of useful lifespan)
- Why Cordova?
  - Cordova selected due to (1) community recently completing undergrounding initiative; (2) CEO showing great interest in this analysis and willingness to provide assumptions; (3) fishing industry extremely sensitive to power interruptions; and (4) extreme weather conditions.

Estimating future lifecycle costs

Step 1

- Collect information on the total line mileage, lifespan, capital, and operations and maintenance (O&M) costs of T&D infrastructure that is currently overhead and underground

Step 2

- Determine the age and length of existing overhead and underground line circuits; project growth in T&D line miles to 2050

Step 3

- Replace lines at end of useful life; calculate the net present capital and O&M costs of T&D lines for the status quo and undergrounding mandate

Step 4

- Subtract status quo lifecycle costs from undergrounding lifecycle costs

= net lifecycle cost from undergrounding mandate

Estimating future benefits from less frequent outages

Step 1

- Apply econometric model (*i.e., LBNL 2015 reliability trends report*) to estimate the total number of outages—under the status quo

Step 2

- Estimate the total number of outages—for the undergrounding alternative—by gradually removing the effect of weather on this same econometric model as the share of undergrounded line miles increases each year

Step 3

- Assign a dollar value for the total number of annual customer outages for both alternatives using information from Sullivan et al. (2015) (*i.e., ICE Calculator*)

Step 4

- Discount all costs back to the base year; subtract the outage-related costs for the undergrounding alternative from the outage costs for the status quo

= avoided outage costs from undergrounding mandate

Estimated benefits (cont.)

ICE CALCULATOR

ICE Calculator | Home | Model Builder | Interruption Cost Model | Reliability Improvement Model | Quick Interruption Cost Model | Quick Reliability Improvement Model

Estimate Interruption Costs

This module provides estimates of cost per interruption event, per average kW, per unserved kWh and the total cost of sustained electric power interruptions.

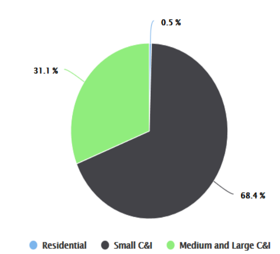
Model #1

Profile | Reliability Index | # of Customers | # of Accounts | Annual Usage | Household Income | Power Interruption | Industry Percentage | Backup Generation

Interruption Cost Estimates

Sector	# of Customers	Cost Per Event	Cost Per Average kW	Cost Per Unserved kWh	Total Cost
Residential	100	$3.77	$3.98	$8.85	$754.52
Small C&I	93	$607.48	$152.48	$338.84	$112,991.27
Medium and Large C&I	7	$3,666.44	$41.90	$93.12	$51,330.23
All Customers	**200**	**$4,277.70**	**$198.36**	**$440.81**	**$165,076.02**

Total Cost of Sustained Interruptions by Sector



http://www.icecalculator.com/

- ICE Calculator is an interactive tool for estimating customer interruption costs for a customized service territory using data from 34 previous utility-sponsored Customer Interruption Costs (Value of Loss Load) surveys

- Utility and other stakeholders often use the ICE Calculator to estimate the benefits of avoiding future (or past) power interruptions

Estimating future avoided aesthetic costs

Step 1

- Estimate number of residential, commercial and industrial, and other properties within an "overhead transmission viewing corridor" which is decreasing in size over time

Step 2

- Multiply number of affected properties against the real estate value for each property class and lost property value associated with overhead high-voltage transmission lines (e.g., 12.5%)

Step 3

- Discount the stream of avoided aesthetic costs back to the present using discount rate (e.g., 10%)

= avoided aesthetic costs from undergrounding mandate

Conversion-related morbidity and mortality costs

Step 1
- Collect information on total number of utility employees; utility sector accident rates and costs from relevant injuries; utility sector fatality rates and the value of statistical life (VSL)

Step 2
- For status quo, multiply fatality and non-fatality incidence rates by VSL and accident costs, respectively, and number of utility employees

Step 3
- For undergrounding alternative, increase fatal and non-fatal incidence rates proportionally as share of underground line miles increases each year; multiply increased fatality and non-fatality incidence rates by VSL and accident costs, respectively, and number of utility employees

Step 4
- For both alternatives, discount all costs back to base year; subtract status quo morbidity/mortality costs from undergrounding morbidity/mortality costs

= net morbidity and mortality costs from undergrounding mandate

Ecosystem-related restoration costs

Step 1
- Estimate the number of acres affected by T&D line growth in the future (using development corridor width and total line miles)—for both alternatives

Step 2
- For both alternatives, multiply total T&D line development corridor acreage against a conservation easement price (e.g., $3,000/acre)

Step 3
- Discount the stream of ecosystem restoration costs back to the present using discount rate

Step 4
- Subtract status quo restoration costs from undergrounding restoration costs

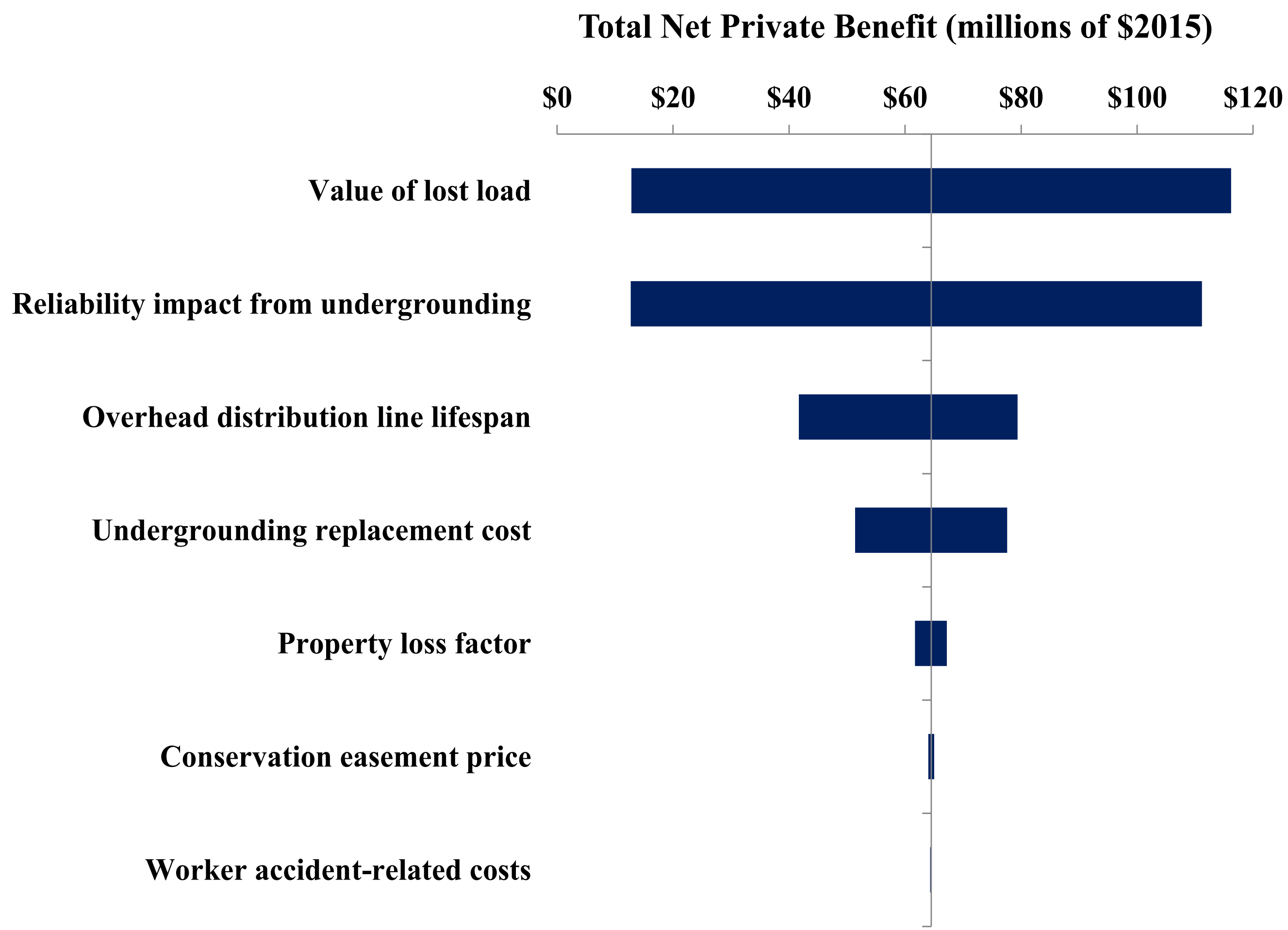
= net ecosystem restoration costs from undergrounding mandate

Key assumptions: Cordova Electric Cooperative

For the base case, it is assumed that half of all distribution-related reductions in the frequency and total minutes customers were without power are a result of the Cordova's decision to underground lines…

		Range			Impact Category				
#	**Sensitivity/ scenario analysis**	**Minimum value (10th %)**	**Base case value (50th %)**	**Maximum value (90th %)**	**Lifecycle assessment (cost)**	**Avoided outages (benefit)**	**Aesthetics (benefit)**	**Worker safety (cost)**	**Ecosystem restoration (benefit)**
1	1978 replacement cost of undergrounding dist. lines ($2015 per mile)	$60,814	$304,070	$547,326	*				
2	Alternative values of lost load for each customer class ($ per event)	-80% below base case values	See Figures 40–42	+80% above base case values		*			
3	Alternative aesthetic-related property loss factors (% of property value)	2.5%	12.5%	22.5%			*		
4	Alternative conservation easement prices ($/acre)	$1,091.2	$5,456	$9,820.8					*
5	Alternative lifespan assumptions for overhead dist. infrastructure (years)	20	40	60	*	*	*	*	*
6	Outage duration and frequency change due to undergrounding activities	25 outages/240 minutes (1978); 22.8 outages/224.3 minutes (2015)	25 outages/240 minutes (1978); 14 outages/161.5 minutes (2015)	25 outages/240 minutes (1978); 5.2 outages/98.7 minutes (2015)		*			
7	Workers compensation direct and indirect cost ($/accident)	$32,143.4	$160,717	$289,290.6				*	

Sensitivity analysis (part II)



- **Cordova's net benefit calculation is most sensitive to the choice of (1) value of lost load; (2) reliability impact from undergrounding; and (3) overhead distribution line lifespan.**