Day 2: Undergrounding Technical Workshop

Solutions for the Future

September 19, 2025

MPSC
MICHIGAN PUBLIC SERVICE COMMISSION

Introduction – U-21388

Late-March 2025

Storm
Ice Storm Hits Northern Michigan

May 21, 2025

Public Forum
Town hall in Gaylord where undergrounding emerged as a key theme

June 12, 2025

Order
Staff to 1) conduct undergrounding workshop and 2) issue report with recommendations

Sept. 2025

Workshops
Staff lead workshops on September 17 and 19

Oct. 31, 2025

Staff Report
Staff to file a report with recommended next steps

Note: Staff explored undergrounding in U-15279 (2007) and issued a report indicating that the reliability benefits of undergrounding are uncertain and did not compare favorably to the costs.

Agenda

Solutions for the Future		
12:00-12:05	Welcome & Introduction	MPSC
12:05-1:00	Valuing Investments in Reliability: A Case Study of Undergrounding	Pete Larsen, Lawrence Berkeley National Laboratory
1:00-1:45	Targeted Undergrounding Benefit-Cost Analysis in Michigan	Luke Dennin, MPSC
1:45-2:30	How to Manage Risk on a Budget	Eric Borden, Synapse Energy Economics
2:30-2:45	Break	
2:45-3:15	Policy Solutions to Support Undergrounding	Eric Dennis, Citizens Research Council of Michigan
3:15-4:00	System Modernization & Reliability Project in Wisconsin: Peer Utility Perspective	Steven Herbel, Wisconsin Public Service
4:00-4:55	Resilience Metrics & Valuation for Electric Grid Decision-Making	Shikhar Pandey, GridCo
4:55-5:00	Closing	MPSC

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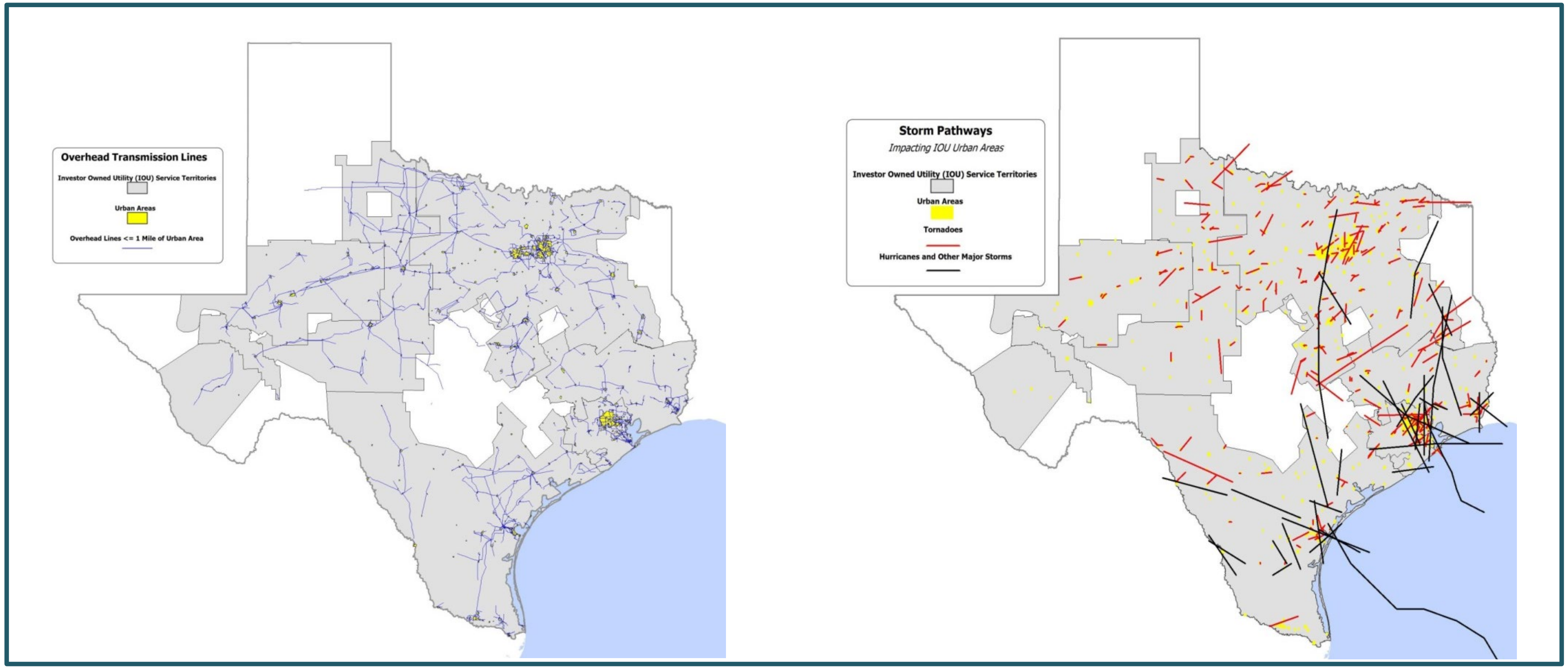
Housekeeping

- Meeting is Recorded
- Workshop Format
  - Questions and discussion at the end of presentations
  - Raise hand feature through Teams in the order received (primary)
  - Questions in the chat (secondary)
  - Presenters may follow up with questions not answered
- Please Mute Unless You Are Speaking

Valuing Investments in Reliability: A Case Study of Undergrounding



Peter Larsen

September 19, 2025 ■ MPSC Undergrounding Technical Workshop

Examples of information needed to value grid investments

Cost	Benefits: Non-monetized	Benefits: Monetized	Other
• Capital/installation • Annual operations and maintenance	• Avoided pollution • Avoided health/safety risk • Avoided damage to utility infrastructure • Reduction in frequency and/or duration of power interruptions • Avoided impacts to national security	• Avoided morbidity and mortality costs • Avoided capital and O&M costs to utility • **Avoided interruption costs to customers (e.g., ICE Calculator)** • Avoided "spillover" effects to regional economy • Avoided aesthetic costs (if applicable)	• Real discount rate (or weighted average cost of capital) • Lifespan of strategy • Local, state, and federal incentives and rebates • Frequency and duration of power interruptions before and after investment • Detailed information about customers impacted

Interruption Cost Estimate (ICE) Calculator

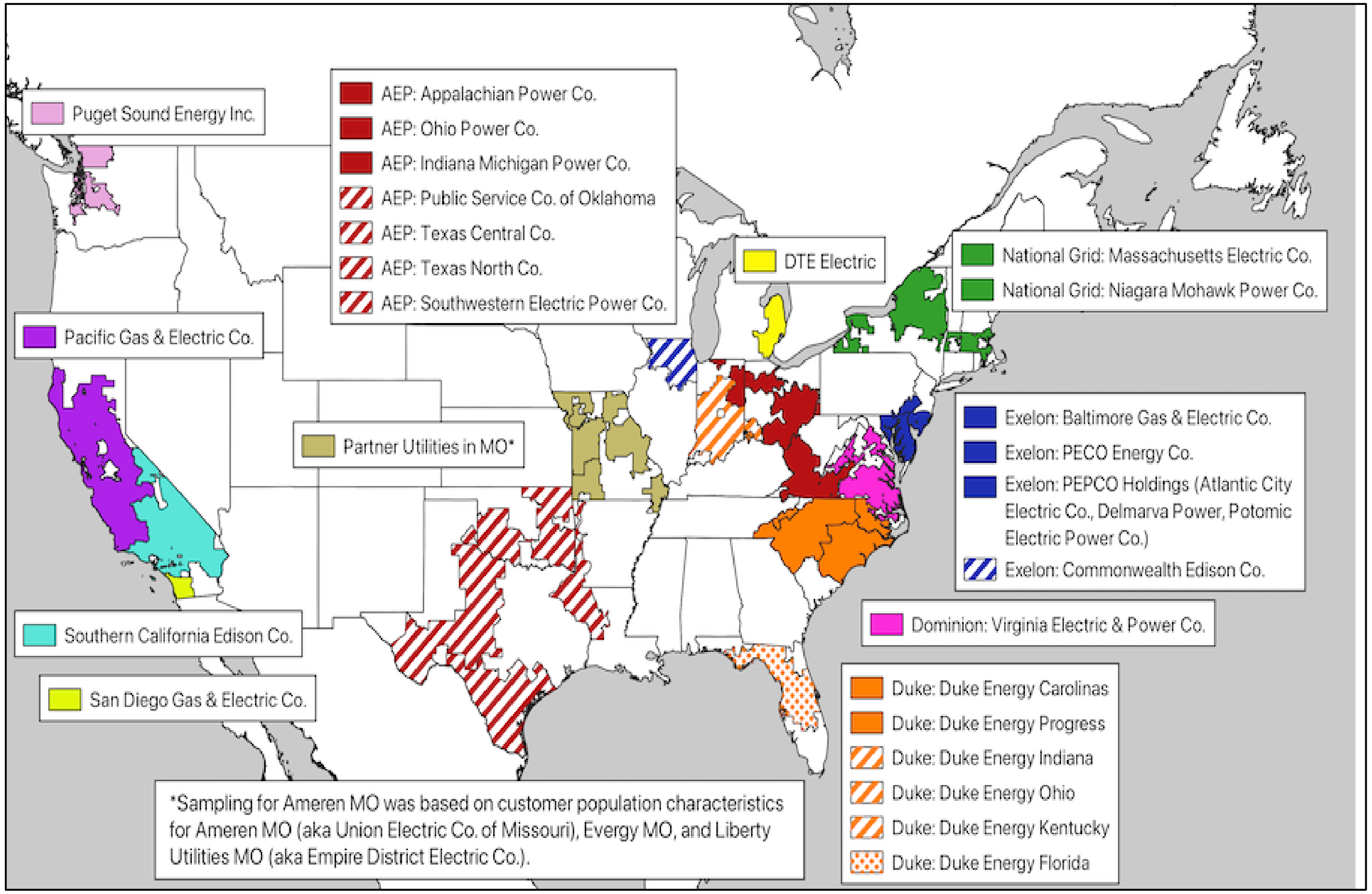
- Berkeley Lab’s ICE Calculator is the leading and only publicly-available tool for estimating the customer cost impacts of power interruptions

- Development of ICE Calculator 1.0 was originally sponsored by the U.S. Department of Energy (DOE)

- ICE Calculator is being used to:
  - Provide a basis for discussing utility reliability investments, *including undergrounding*, with regulators
  - Assess the economic impact of past power outages

- We are updating and upgrading the ICE Calculator (“ICE Calculator 2.0”) via a national, public-private partnership

ICE Calculator update happening in phases



Phase 1 & 2

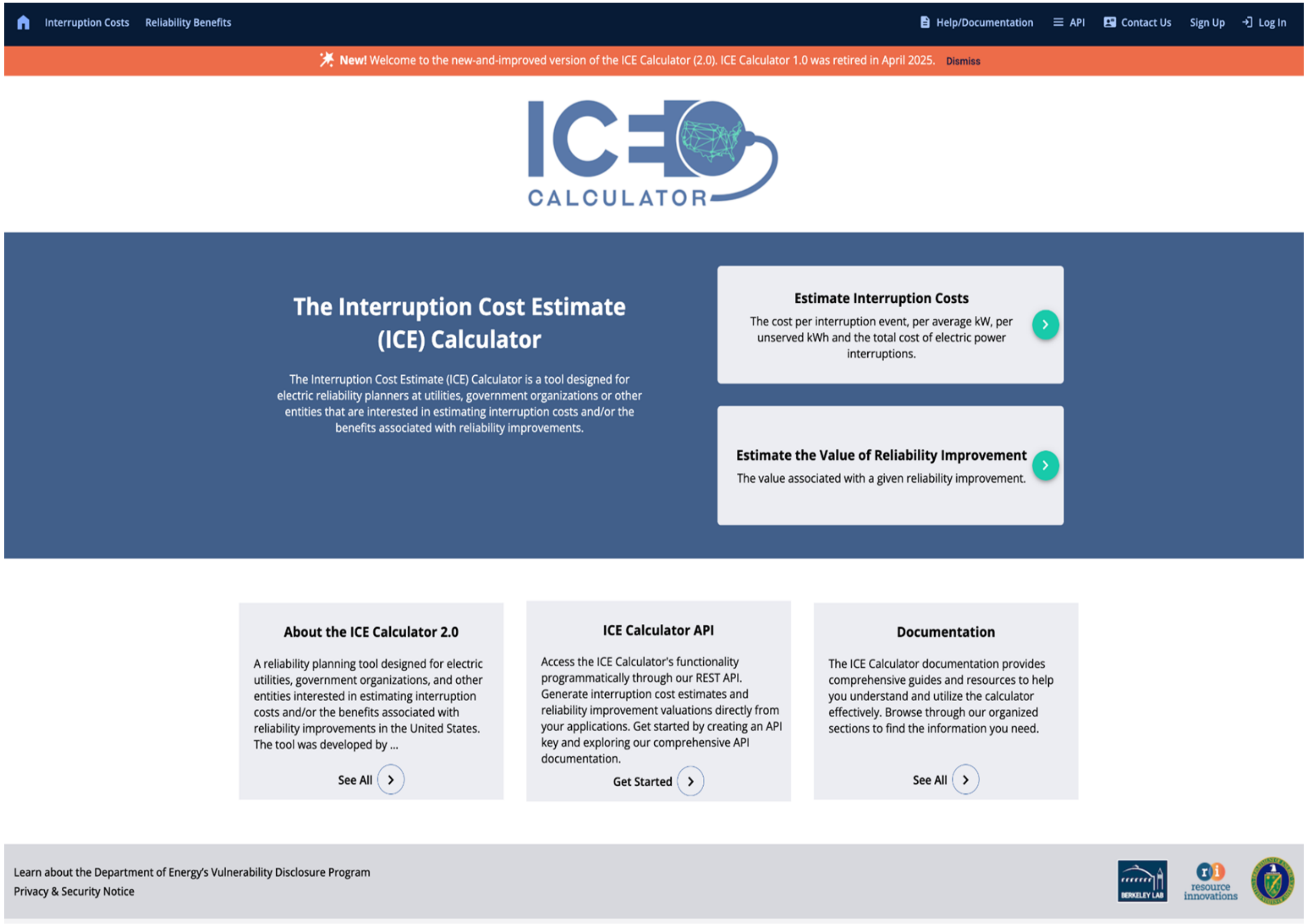
- 12 sponsors
- 15 distinct survey activities
- 30 investor-owned utility distribution service territories represented

Phase 3

- We received support from DOE to partner with NRECA to survey select rural cooperatives across the U.S.
- One utility in the West
- Recruiting ongoing

ICE Calculator 2.0 Website: https://icecalculator.com/

- ICE Calculator 2.0 released on April 28, 2025
- Additional updates over the coming months/years



Background on undergrounding research

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

Energy Policy 49 (2012) 243–252

Contents lists available at SciVerse ScienceDirect

Energy Policy

journal homepage: www.elsevier.com/locate/enpol

Distribution-level electricity reliability: Temporal trends using statistical analysis

Joseph H. Eto*, Kristina H. LaCommare, Peter Larsen, Annika Todd, Emily Fisher

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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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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 Texas electric utility transmission and distribution (T&D) infrastructure were "far in excess of the quantifiable storm benefits"

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

Analysis framework: Texas IOUs

- Study perspective:
  - Individuals who care about maximizing private benefits
- Key stakeholders with standing:
  - Investor-owned utilities (IOUs), ratepayers, and all residents within service territory
- Policy alternatives:

  (1) 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 Texas?

  -Texas IOU service territories were selected due to (1) previous study evaluating costs and (some) benefits of undergrounding; (2) ready access to useful assumptions; and (3) public utility commission showing interest in undergrounding major portions of electrical grid

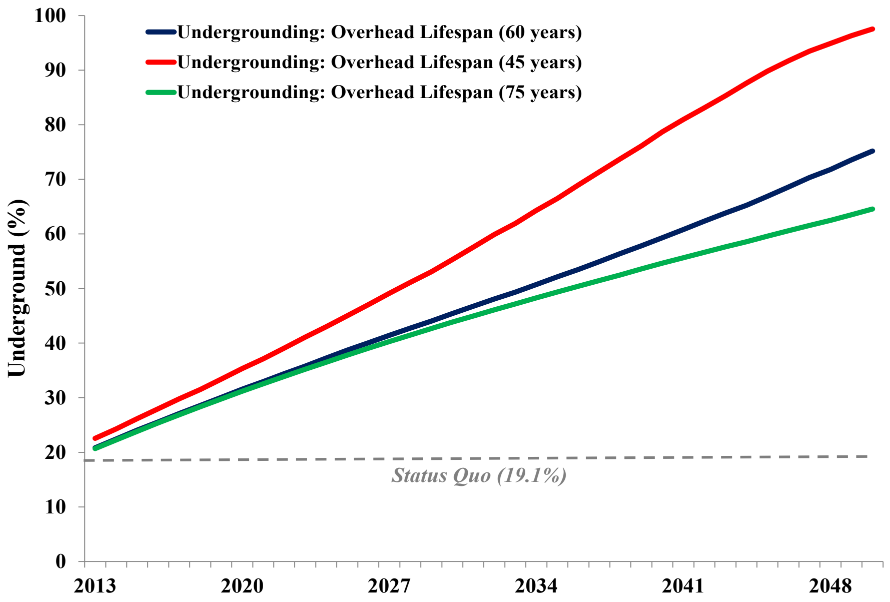
Analysis framework: Texas IOUs (cont.)

Key Stakeholders	**Undergrounding Mandate**	
	Selected Costs	**Selected Benefits**
IOUs	• Increased worker fatalities and accidents*	
Utility ratepayers	• Higher installation cost of underground lines***** • Additional administrative, siting, and permitting costs associated with undergrounding* • Increased ecosystem restoration/right-of-way costs**	• Lower operations and maintenance costs for undergrounding*
All residents within service area		• Avoided societal costs due to less frequent power outages*** • Avoided aesthetic costs**

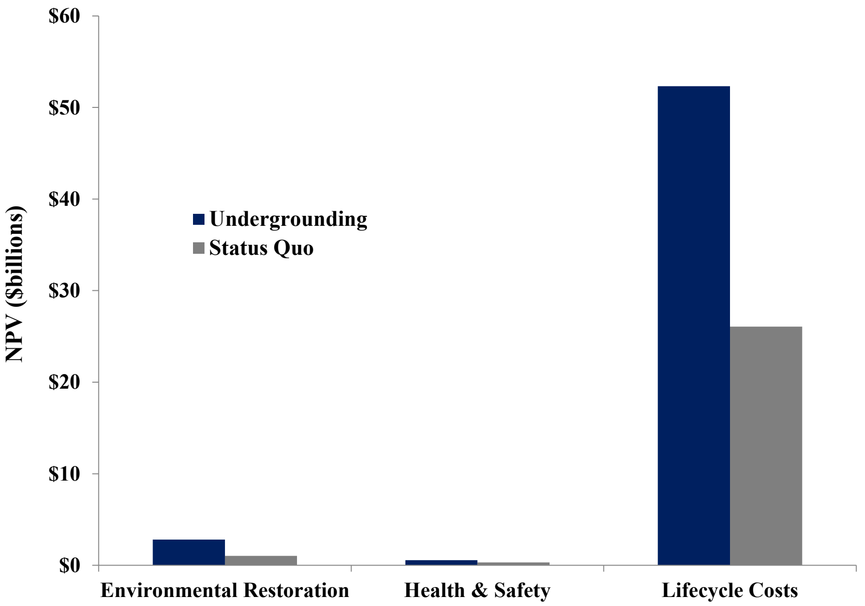
Key:

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

Estimated costs

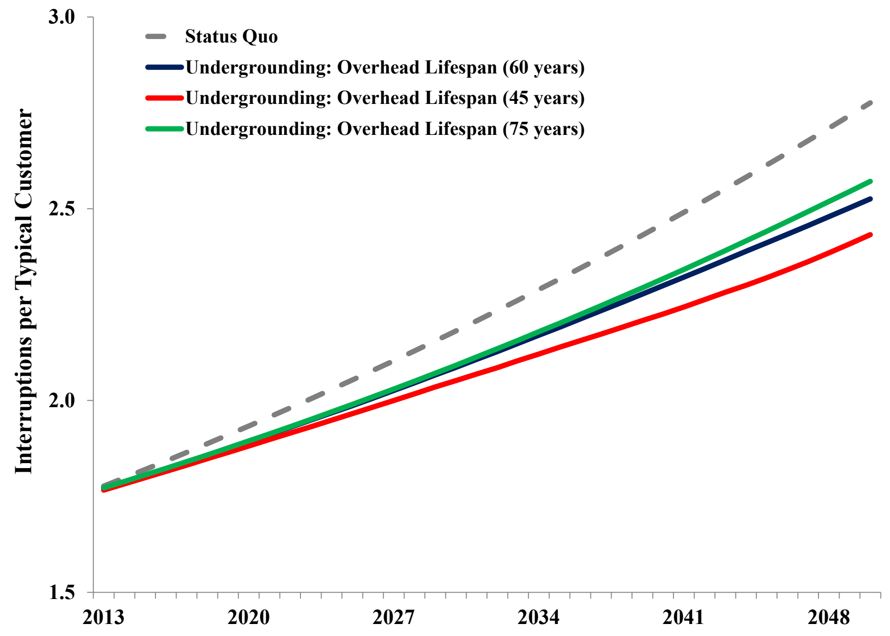


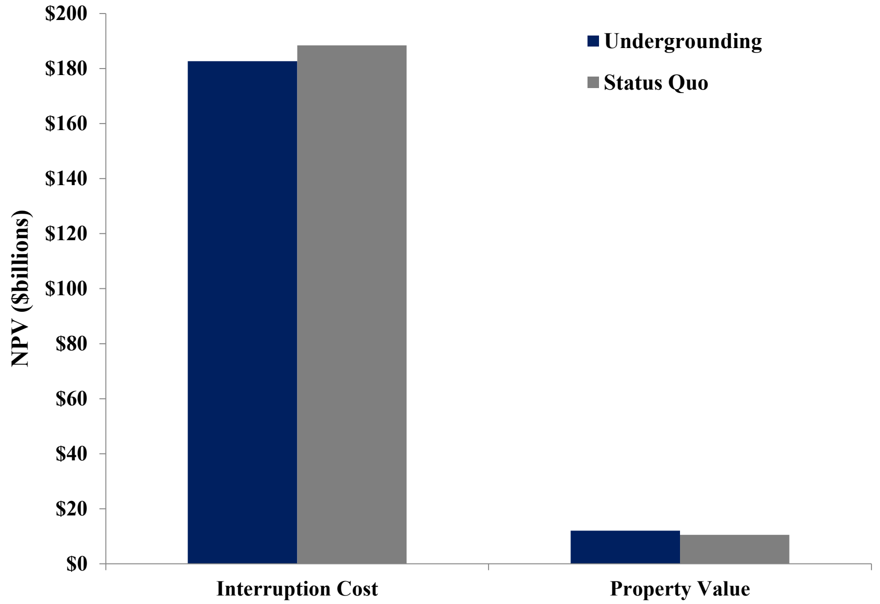
- Underground mileage share increasing over time under alternative overhead lifespan assumptions



- NPV of undergrounding and status quo costs ($2012)

Estimated benefits





- Projected power outages over time under alternative overhead lifespan assumptions

- NPV of undergrounding and status quo benefits/avoided costs ($2012)

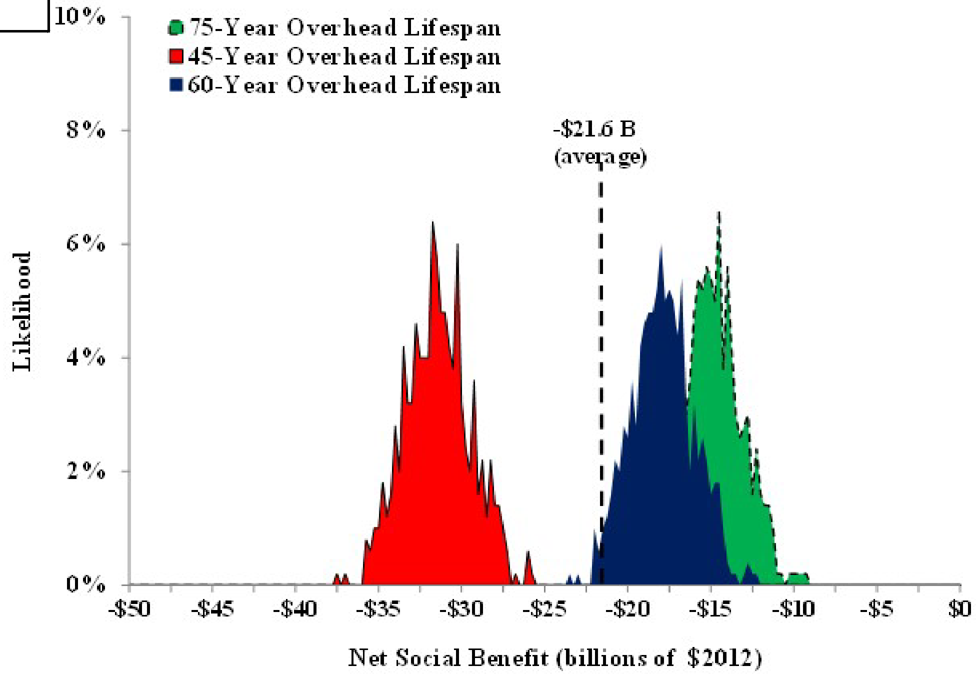
- ICE Calculator 1.0 was used to estimate avoided interruption costs

Net social loss

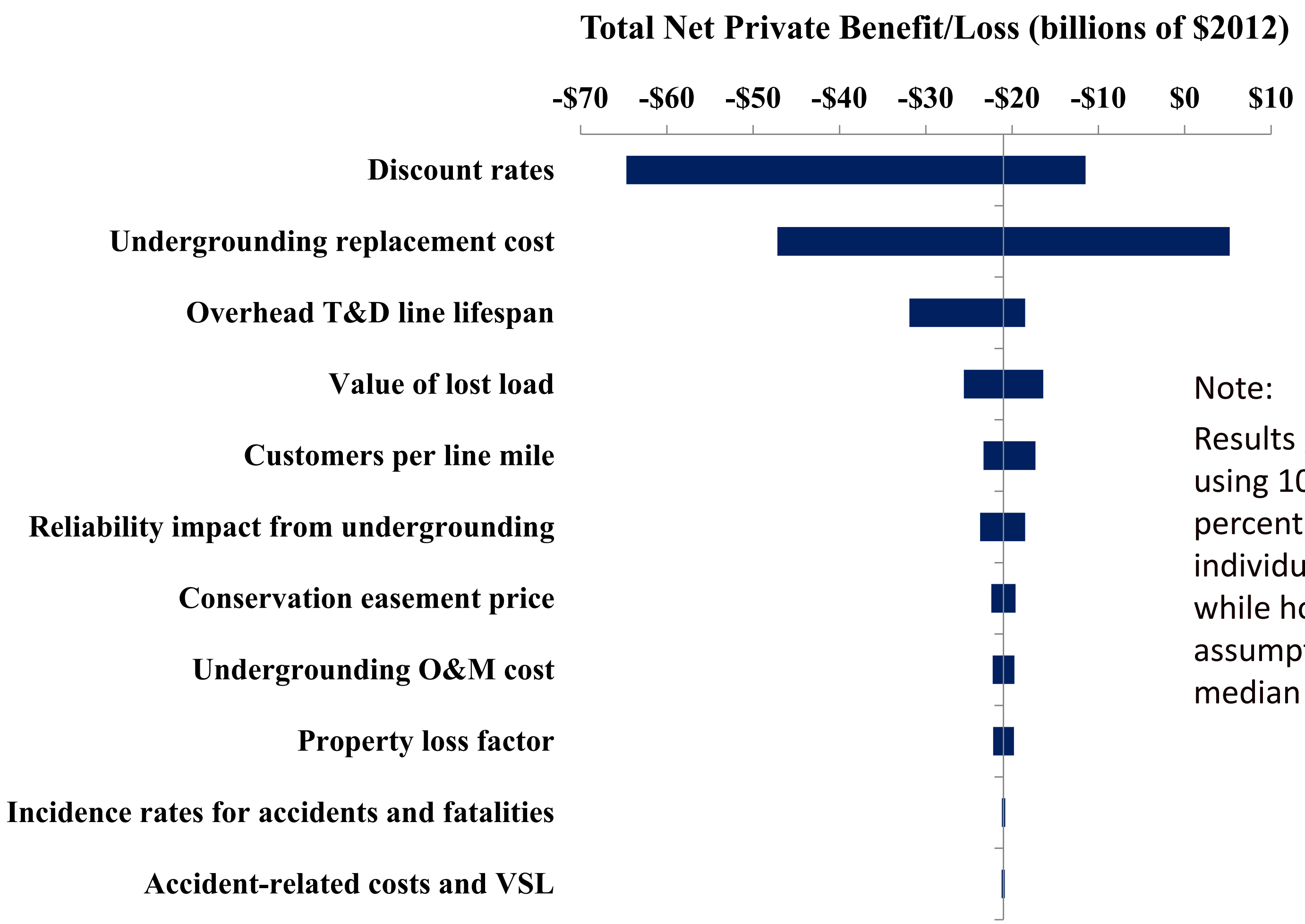
Impact Category	Undergrounding	Status Quo	Net Cost ($billions)
Environmental restoration	$2.8	$1.0	$1.8
Health & safety	$0.56	$0.31	$0.2
Lifecycle costs	$52.3	$26.1	$26.3
Total net costs (Undergrounding)			$28.3
Impact Category	**Undergrounding**	**Status Quo**	**Net Benefit ($billions)**
Interruption cost	$182.7	$188.4	$5.8
Avoided aesthetic costs	$12.1	$10.6	$1.5
Total net benefits (Undergrounding)			$7.3
Net Social Benefit (Undergrounding)			
Net social benefit (billions of $2012)			**-$21.0**
Benefit-cost ratio			**0.3**

Additional lifecycle costs associated with undergrounding dominate cost-benefit results

Varying all key assumptions simultaneously led to **consistent net social losses**



Sensitivity analysis



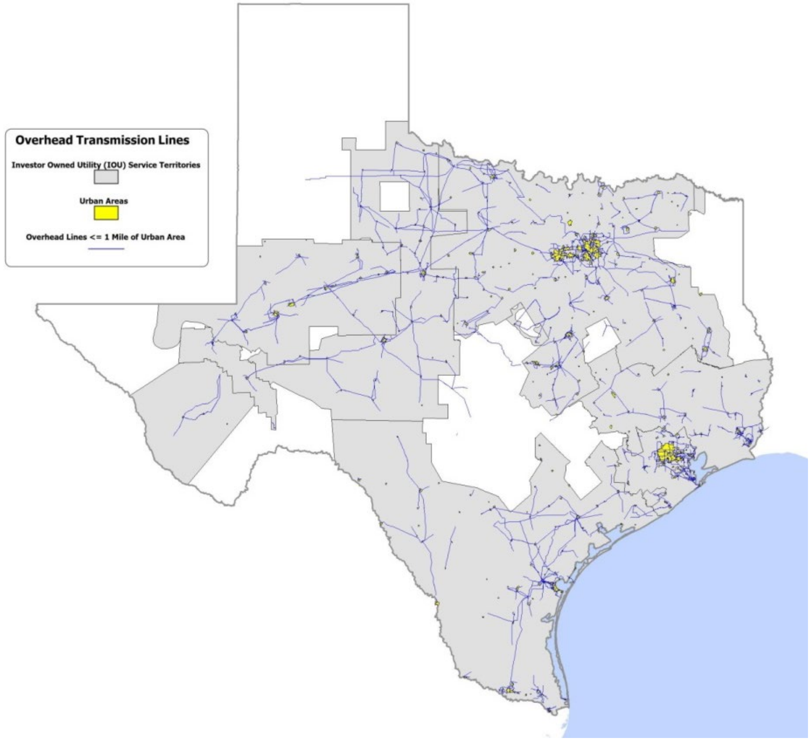
Note:

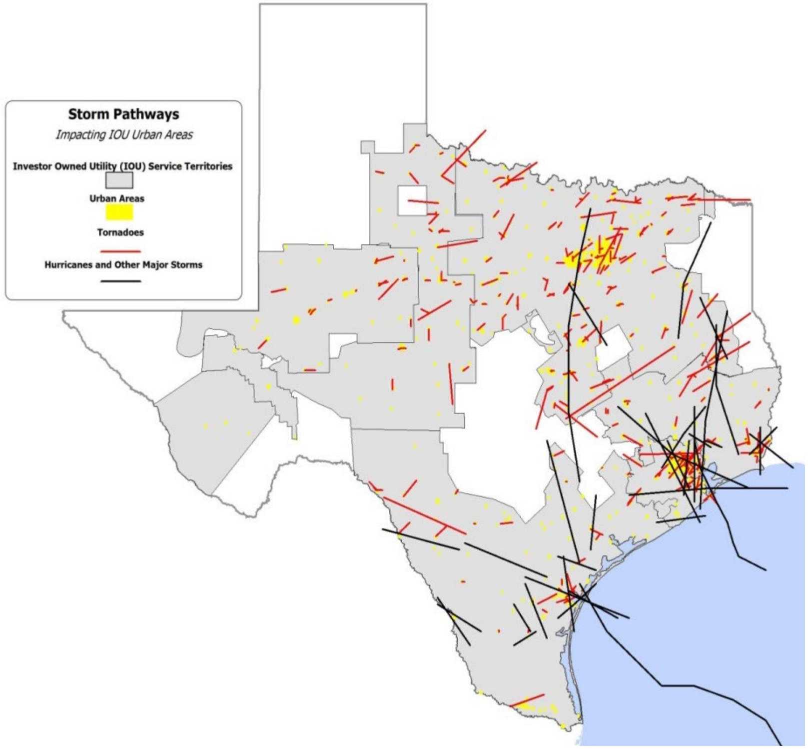
Results generated by using 10th (90th) percentile value for individual assumption while holding all other assumptions constant at median value.

- Net benefit (loss) calculation is **most sensitive to the choice of (1) discount rates; (2) undergrounding replacement cost; (3) overhead T&D lifespan; (4) value of lost load; and (5) customers per line mile (population density)**

Possibility of net benefits

- Based on the initial configuration of this model, the **Texas public utility commission <u>should not</u> consider broadly mandating undergrounding when overhead T&D lines have reached the end of their useful life**



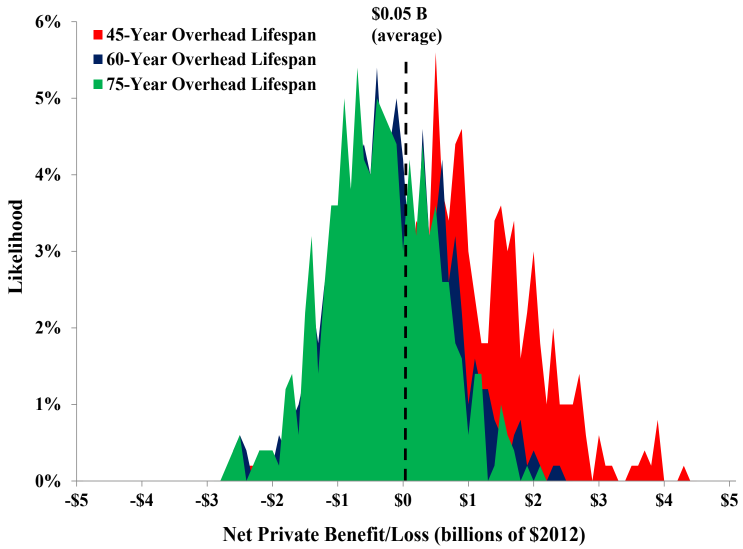


- *What are minimum conditions necessary for a targeted undergrounding initiative to have positive net benefits?*

Possibility of net benefits (cont.)

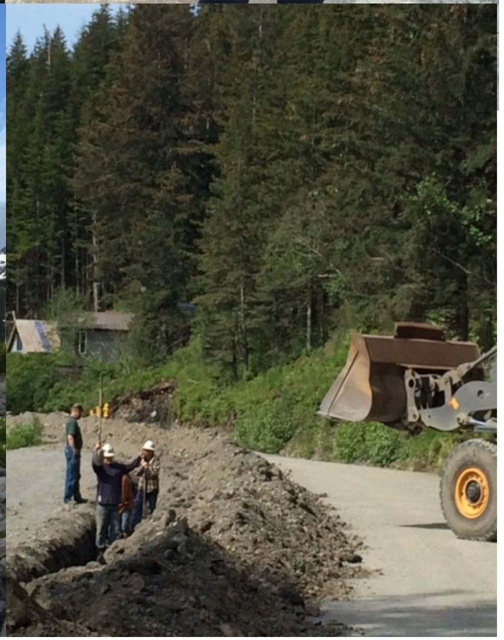
Texas policymakers should consider requiring that all T&D lines be undergrounded in places where:

- **there are a large number of customers per line mile** (e.g., greater than 40 customers per T&D line mile)
- **there is an expected vulnerability to frequent and intense storms**
- **there is the potential for underground T&D line installation economies-of-scale** (e.g., ~2% decrease in annual installation costs expected per year)
- **overhead line utility easements (i.e., rights-of-way) are larger than underground line utility easements**



(Under)ground-truthing: Cordova, Alaska

Author (May 2015)



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.

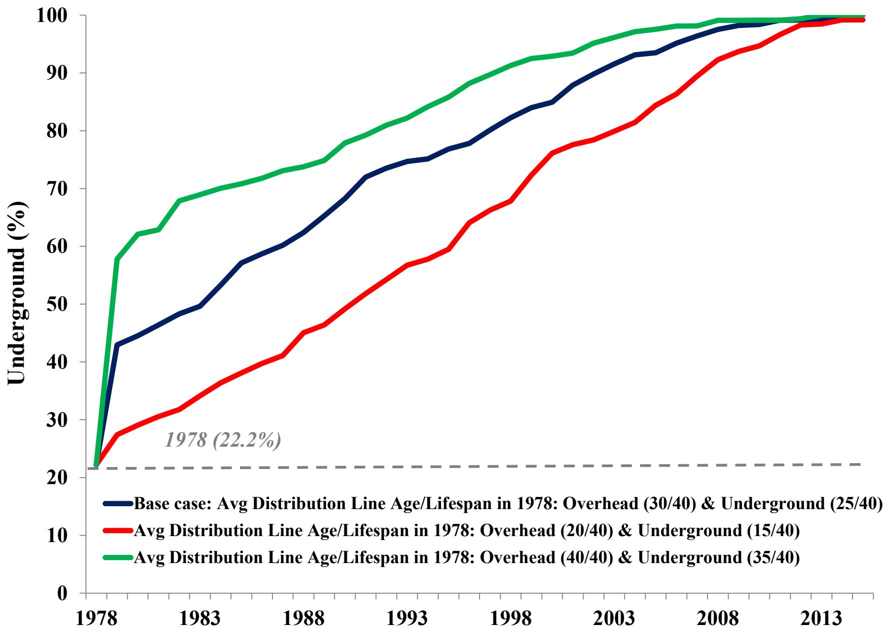
Analysis framework: Cordova case (cont.)

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]

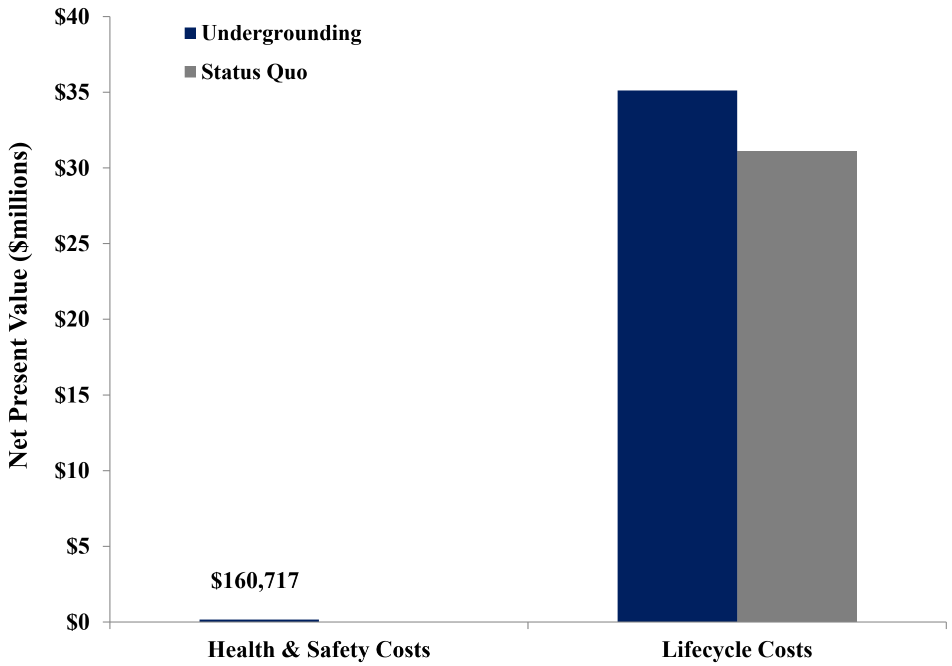
Key:

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

Estimated costs

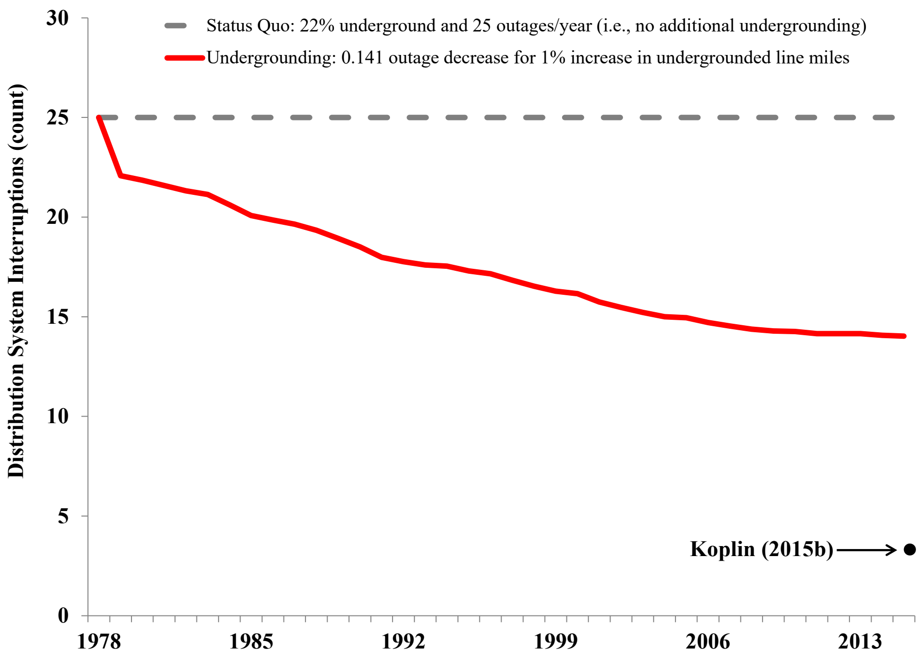


- NPV of undergrounding and status quo costs ($2015)

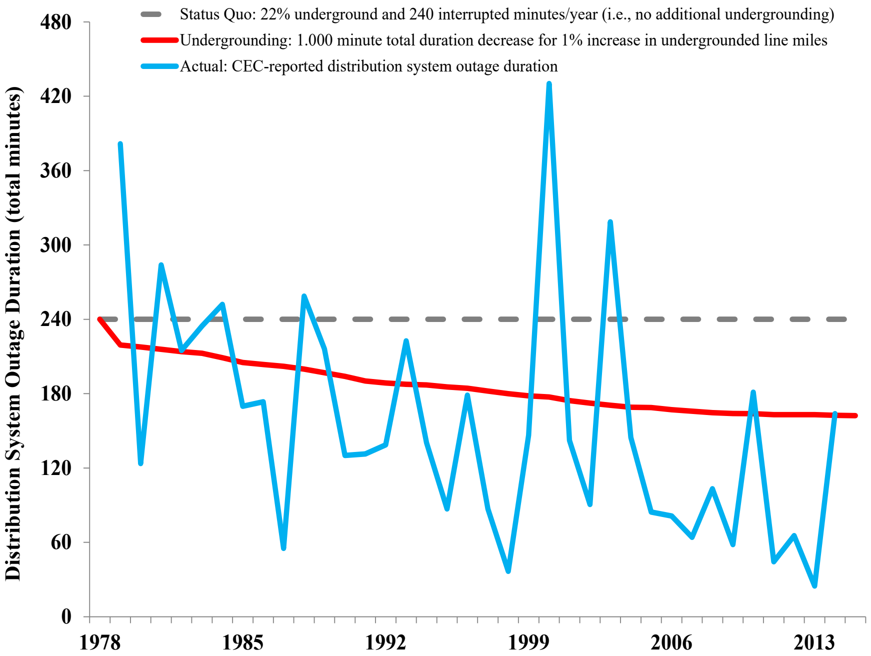


Estimated benefits

Customer interruptions



Interruption minutes

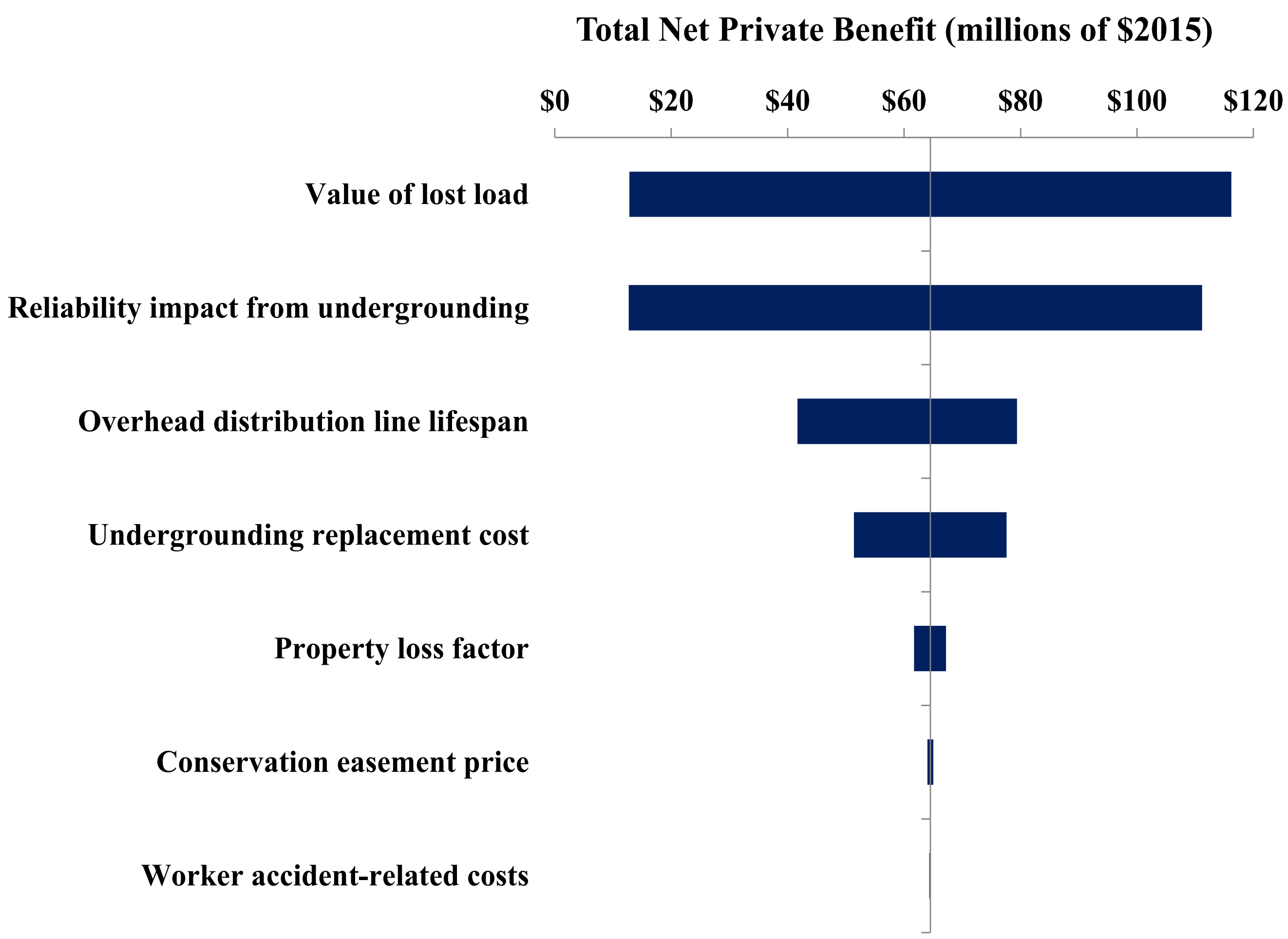


Net social benefit

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**

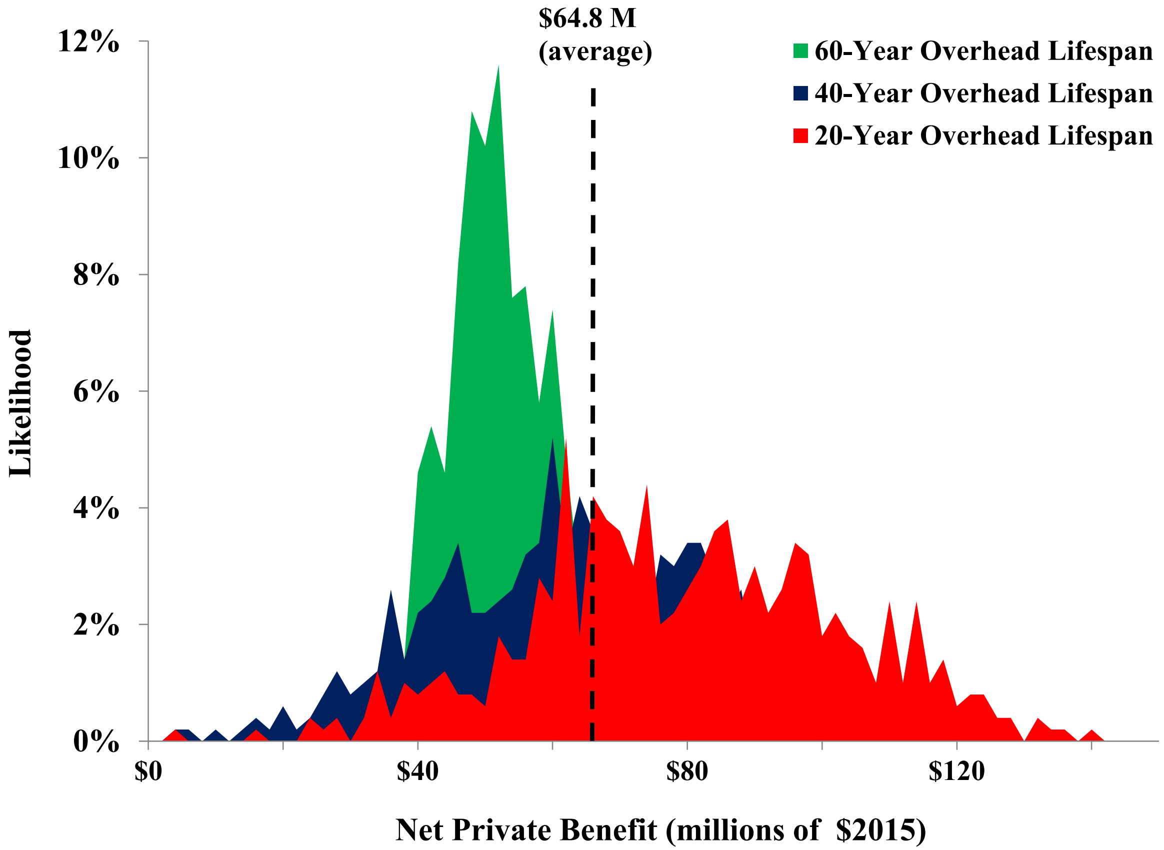
NOTE: **Reliability benefits, although large, are not necessary for cost-effectiveness**.

Sensitivity analysis



- **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.**

Sensitivity analysis (cont.)



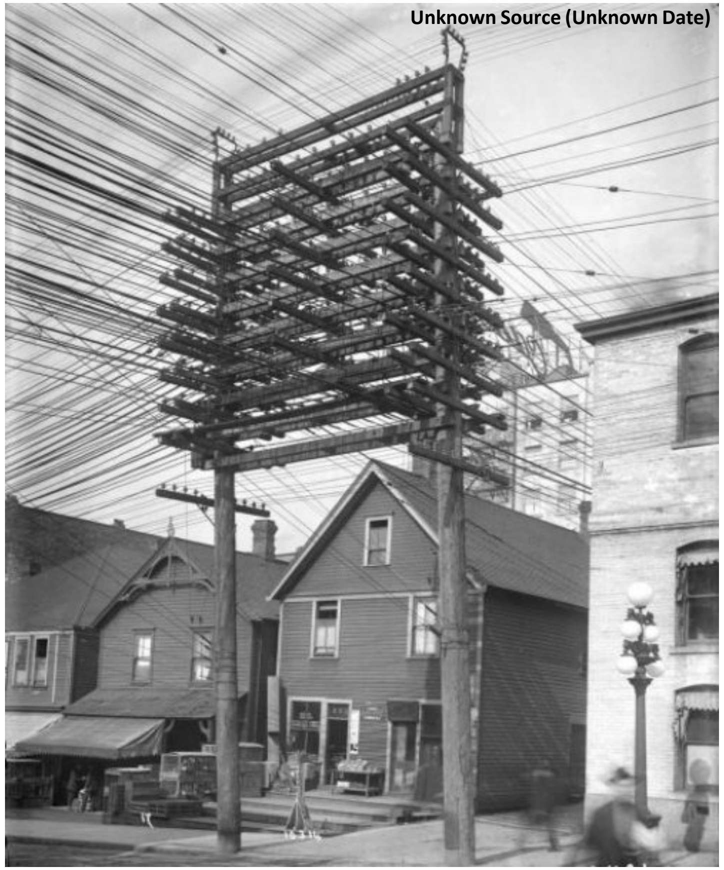
- A Monte-Carlo simulation was conducted by sampling all of the key input assumptions from uniform distributions—bounded by the minimum and maximum values reported earlier— simultaneously

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

Overall conclusion

- 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 resiliency and reliability** (e.g., grid hardening activities)

Thank you



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Appendix

Estimating 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 for IOUs operating in Texas

Step 2
- Randomly 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 through 2050 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 benefits from less frequent outages

Step 1

- Apply econometric model (*i.e., LBNL 2015 reliability trends report*) to estimate the total number of Texas IOU outages—under the status quo—from now until 2050

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

Estimating 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

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

Conversion-related morbidity and mortality costs

Step 1
- Collect information on total number of IOU 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 IOU 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 IOU 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

Key assumptions: Texas IOUs

		Range			Impact Category				
#	Sensitivity/ scenario analysis	Minimum value (10^{th} %)	Base case value (50^{th} %)	Maximum value (90^{th} %)	Lifecycle assessment (cost)	Avoided outages (benefit)	Aesthetics (benefit)	Health and safety (cost)	Ecosystem restoration (cost)
1	Alternative replacement cost of undergrounding T&D lines ($ per mile)	$71,400 (dist.) $336,000 (trans.)	$357,000 (dist.) $1,680,000 (trans.)	$642,600 (dist.) $3,024,000 (trans.)	*	*			
2	Alternative values of lost load for each customer class ($ per event)	$0.5 (residential) $87 (other) $1,843.4 (C&I)	$2.7 (residential) $435 (other) $9,217 (C&I)	$4.9 (residential) $783 (other) $16,590.6 (C&I)		*			
3	Alternative discount rates (%)	2%	10%	18%	*	*	*	*	*
4	Alternative aesthetic-related property loss factors (% of property value)	2.5%	12.5%	22.5%			*		
5	Alternative incidence rates for accidents and fatalities (per 100,000 employees)	420 (non-fatal) 3 (fatal)	2,100 (non-fatal) 15 (fatal)	3,780 (non-fatal) 27 (fatal)				*	
6	Alternative accident costs and VSL ($ per accident/$ per life)	$26,131.6 $1,380,000 (VSL)	$130,658 $6,900,000 (VSL)	$235,184.4 $12,420,000 (VSL)				*	
7	Alternative conservation easement prices ($/acre)	$600	$3,000	$5,400					*
8	Alternative lifespan assumptions for overhead T&D infrastructure (years)	45	60	75	*	*	*	*	*
9	Share of underground line miles impact on reliability	-0.0002	-0.001	-0.0018		*			
10	Number of customers per line mile	15	75.0	135		*			
11	Annual O&M cost expressed as % of replacement cost: underground T&D lines	1% (trans.) 0.1% (dist.)	5% (trans.) 0.5% (dist.)	9% (trans.) 0.9% (dist.)	*				

Key assumptions: Cordova Electric Coop.

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				*	

Targeted Undergrounding Benefit-Cost Analysis in Michigan

MPSC Case U-21388:
Undergrounding Workshop

Luke Dennin, Ph.D.

U.S. Department of Energy Fellow
Michigan Public Service Commission

September 19, 2025

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Does strategic undergrounding make sense?

- **Conventional wisdom suggests that undergrounding is cost prohibitive**

- **However, the electricity sector is shifting**
  1. Extreme weather is increasing in frequency and intensity
  2. Electrification is growing

- **Previous work suggests undergrounding may be cost effective in specific circumstances (Larsen, 2016)**

- **This work conducts circuit-level benefit-cost analysis (BCA) of overhead-to-underground conversions across Consumers Energy's (CE's) service territory, evaluating a targeted approach**

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Agenda for the Talk

1. **Notes on BCA and this study's research design**
2. **Reliability projections and improvements from undergrounding**
3. **Average outcome and value stream review**
4. **Detailed findings**
   - Circuit-level outcomes
   - Uncertainty analysis
   - Portfolio analysis
5. **Conclusions**

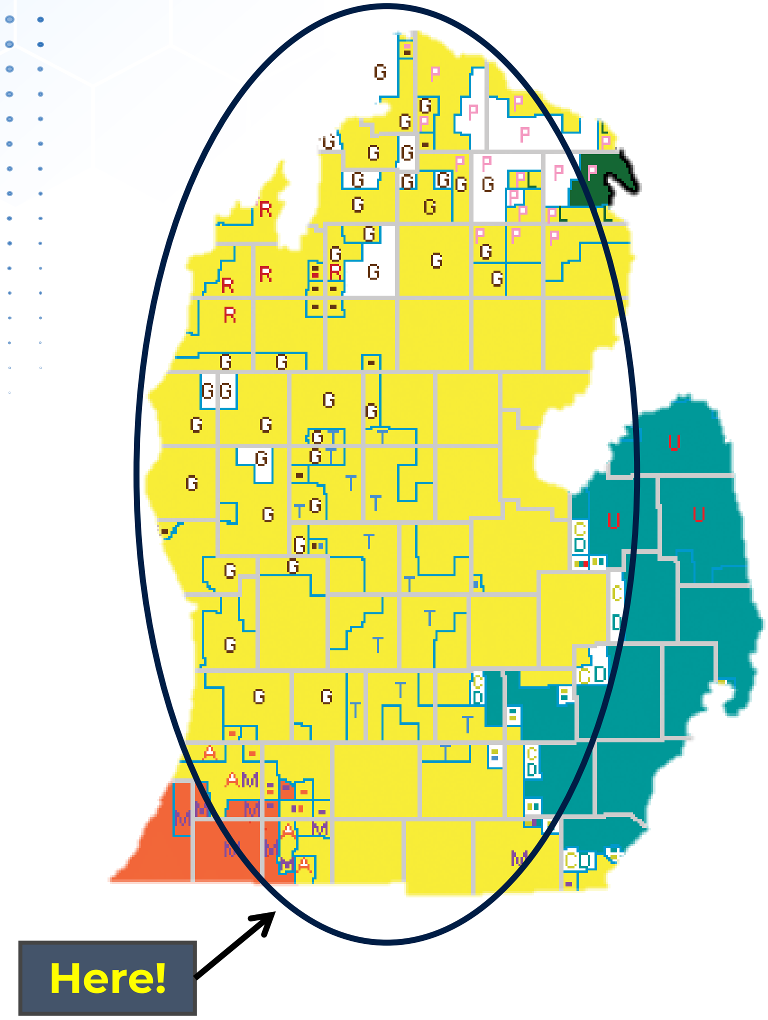
1. Notes on BCA and this study's research design

BCA is a decision-making framework that quantitatively weighs pros and cons

Benefits + **Costs** = **Net Value**

1. **BCA provides an "apples-to-apples" comparison by transforming impacts into comparable units being $**
2. **Attributing $ values to project components is difficult and uncertain**
3. **Anything not explicitly included is implicitly given a zero $ value**
4. **BCA is one of several decision-making considerations**
   - We may choose not move forward with a project yielding net benefits
   - We may choose to move forward with a project yielding net costs
   - Other considerations: Affordability, equity, risk aversion, decision-maker preferences

Notes on this study's research and analysis design



Component Selection

- One-mile single-phase lateral projects
- Undergrounding vs. rebuilding overhead
- Circuit-level impact assessment

Lifecycle Net Present Value

- Analysis timespan of 50 years—2024 to 2074
- Social discount rate of 3%

Utility Data + External Data

- Utility system characteristics and costs
- Extreme weather projections
- Economic information, trends, and models

Systematic Approach to Uncertainty

- Monte Carlo simulations
- Sensitivity analysis

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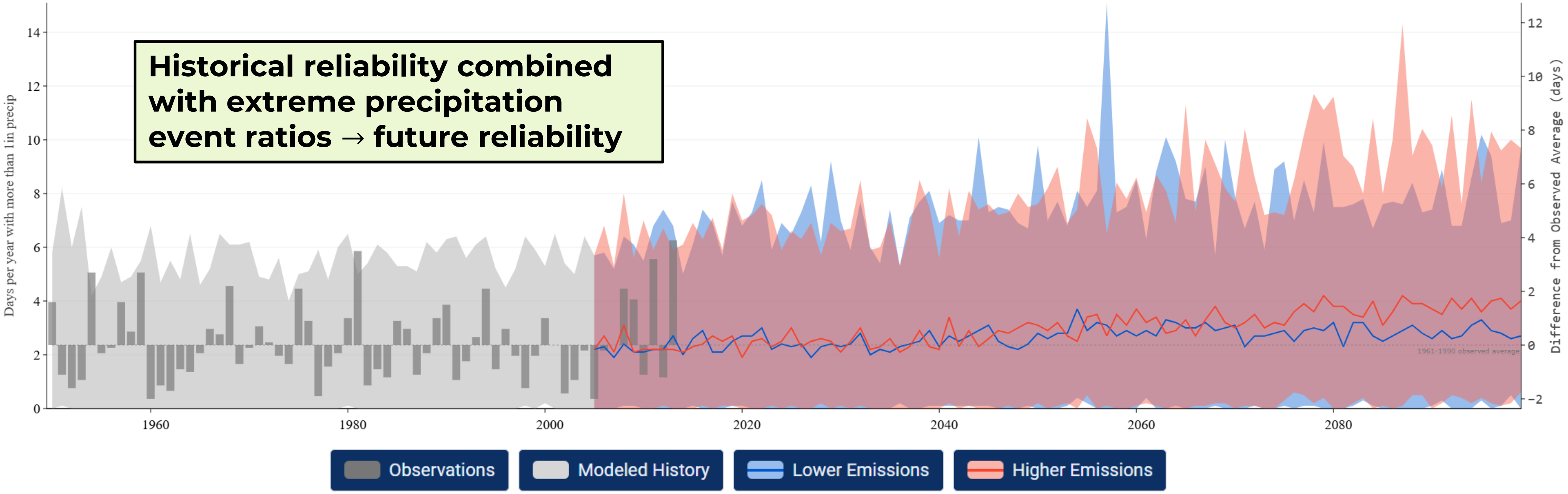
2. Reliability projections and improvements from undergrounding

Extreme weather projections from NOAA's Climate Explorer guide future reliability metric estimates

Source: https://crt-climate-explorer.nemac.org/



Historical reliability combined with extreme precipitation event ratios → future reliability

What are the reliability improvements from undergrounding under different outage conditions?

- **Approach:** Regression analysis of reliability metrics vs. underground line share.

- **Data:** >1,900 circuits, 5 years, 3 outage conditions + an all-condition model:
  - Blue Sky: <1% of customers out
  - Gray Sky: <10% of customers out
  - Catastrophic: >10% of customers out

- **Objective:** Assess effect of undergrounding on SAIFI and SAIDI, controlling for other variables (e.g., tree density, customer counts).

Beta coefficients informing reliability impacts

Condition	SAIFI	SAIDI
All Condition	-4.87E-03***	-8.02E-03***
Blue Sky	-2.48E-03*	-5.61E-04
Gray Sky	-6.51E-03**	-9.24E-03***
Catastrophic	-7.36-03**	-8.51E-03***

Note: *** p < 0.01; ** p < 0.05; * p < 0.10; ‘ ’ p ≥ 0.10

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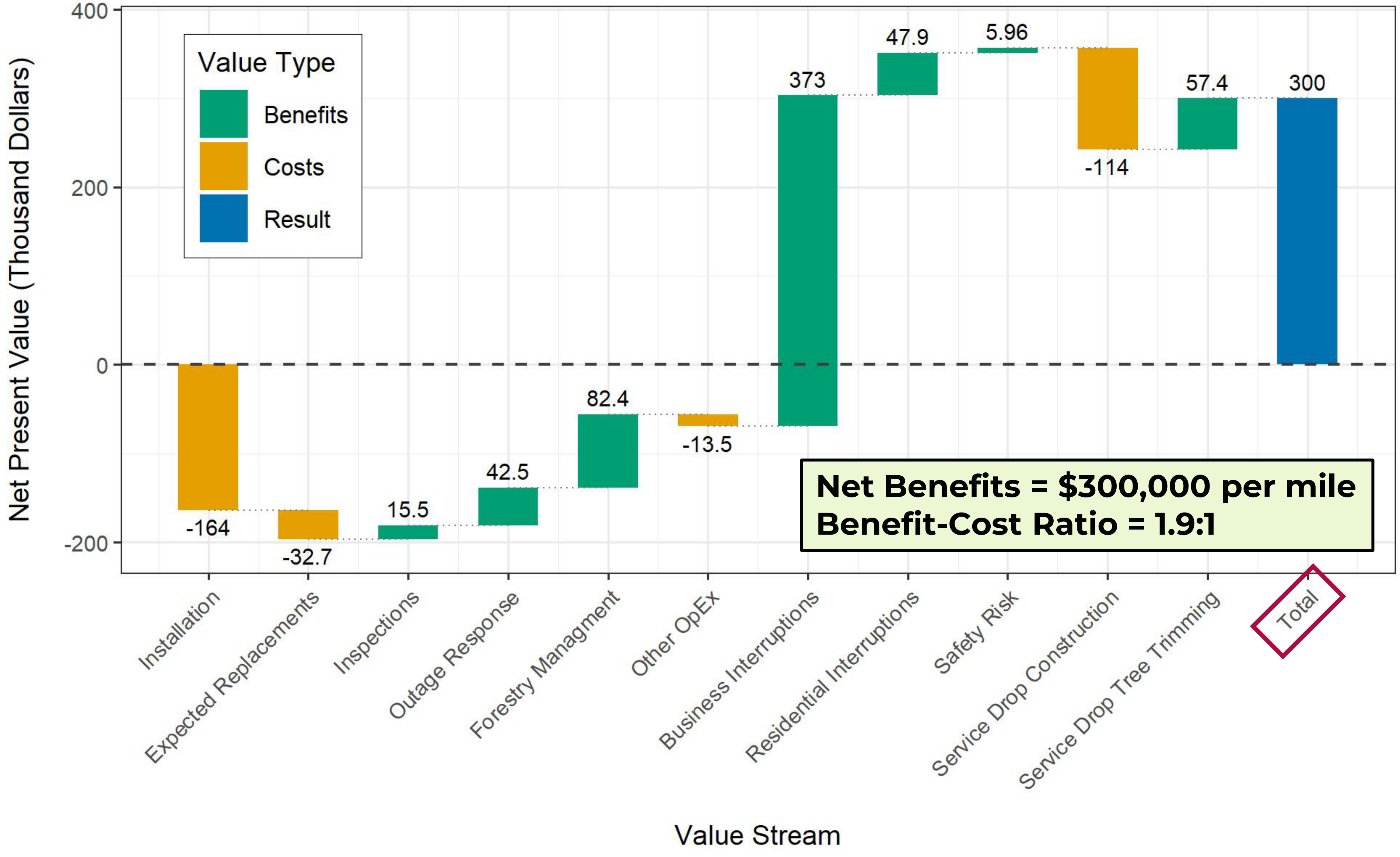
3. Average outcome and value stream review



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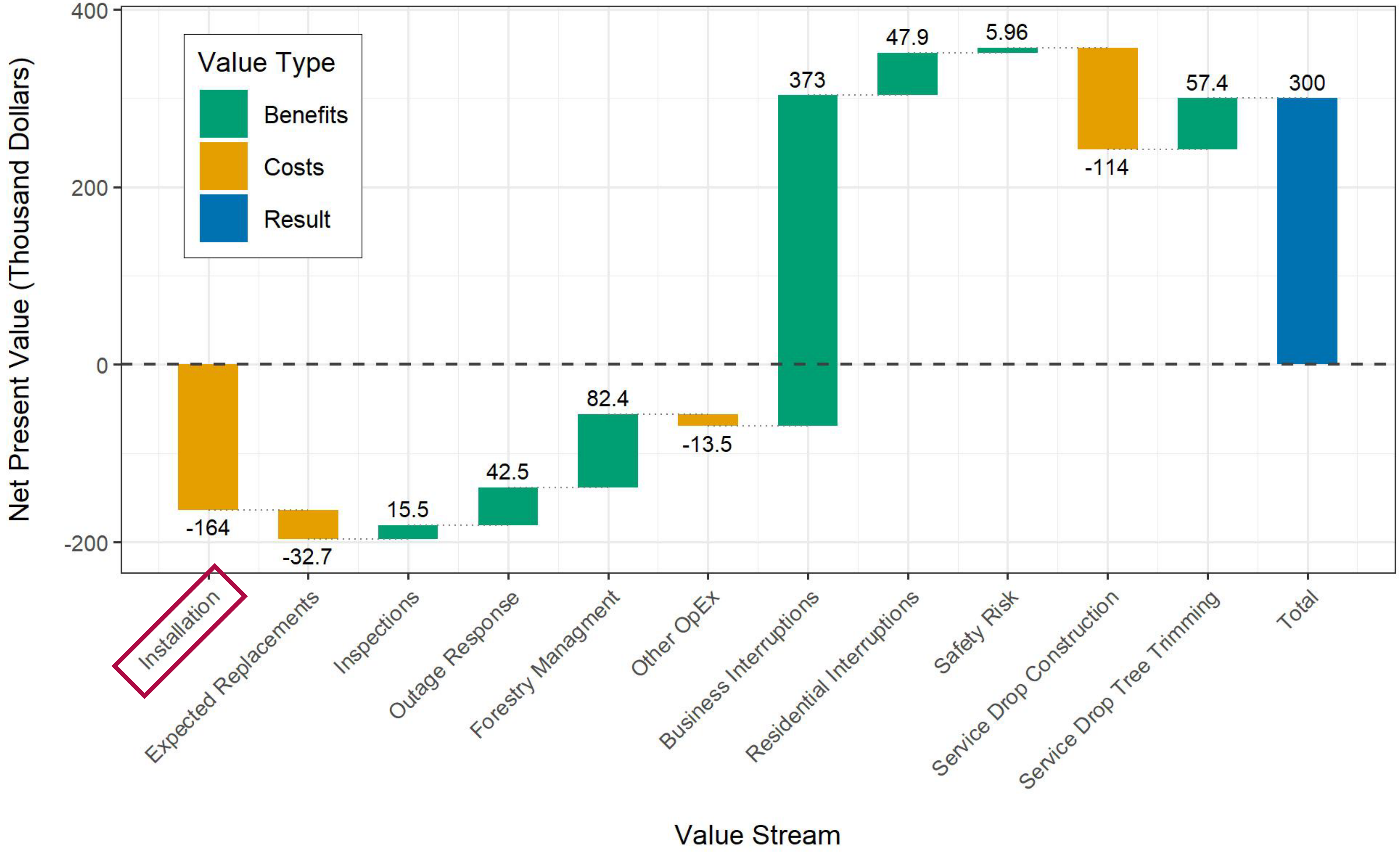

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Installation costs are informed by EPRI's Undergrounding Cost Study and Industry Scan

EPRI | ELECTRIC POWER RESEARCH INSTITUTE

*****Underground conversions are about 2.5x as expensive as overhead**

Single-phase lateral installation costs

Project Scope	Area Type	Installation CapEx (Thousand $ per Mile)						
		Overhead	Underground New Build			Underground Conversion		
			Estimate	Difference vs. OH		Estimate	Difference vs. OH	
Services Excluded	Urban	131	275	+144	2.10x	329	+198	2.51x
	Suburban	103	208	+105	2.02x	250	+147	2.43x
	Rural	83.9	180	+96.5	2.15x	216	+133	2.58x
Services Included	Urban	214	449	235	2.10x	539	+325	2.51x
	Suburban	168	341	172	2.02x	409	+240	2.43x
	Rural	137	295	158	2.15x	354	+217	2.58x

***Source*:** Derived from Tripolitis et al. (2015) – Link

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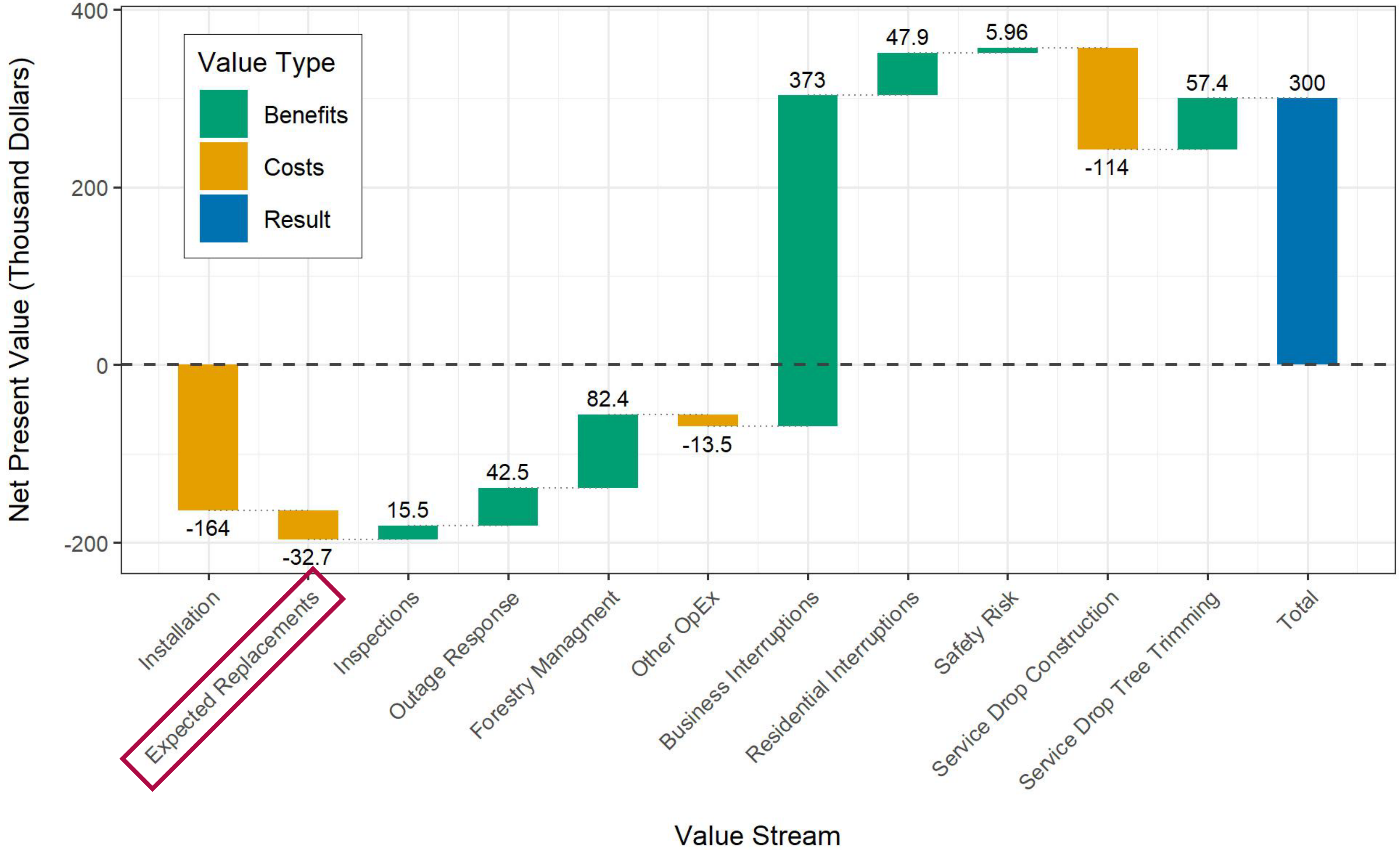

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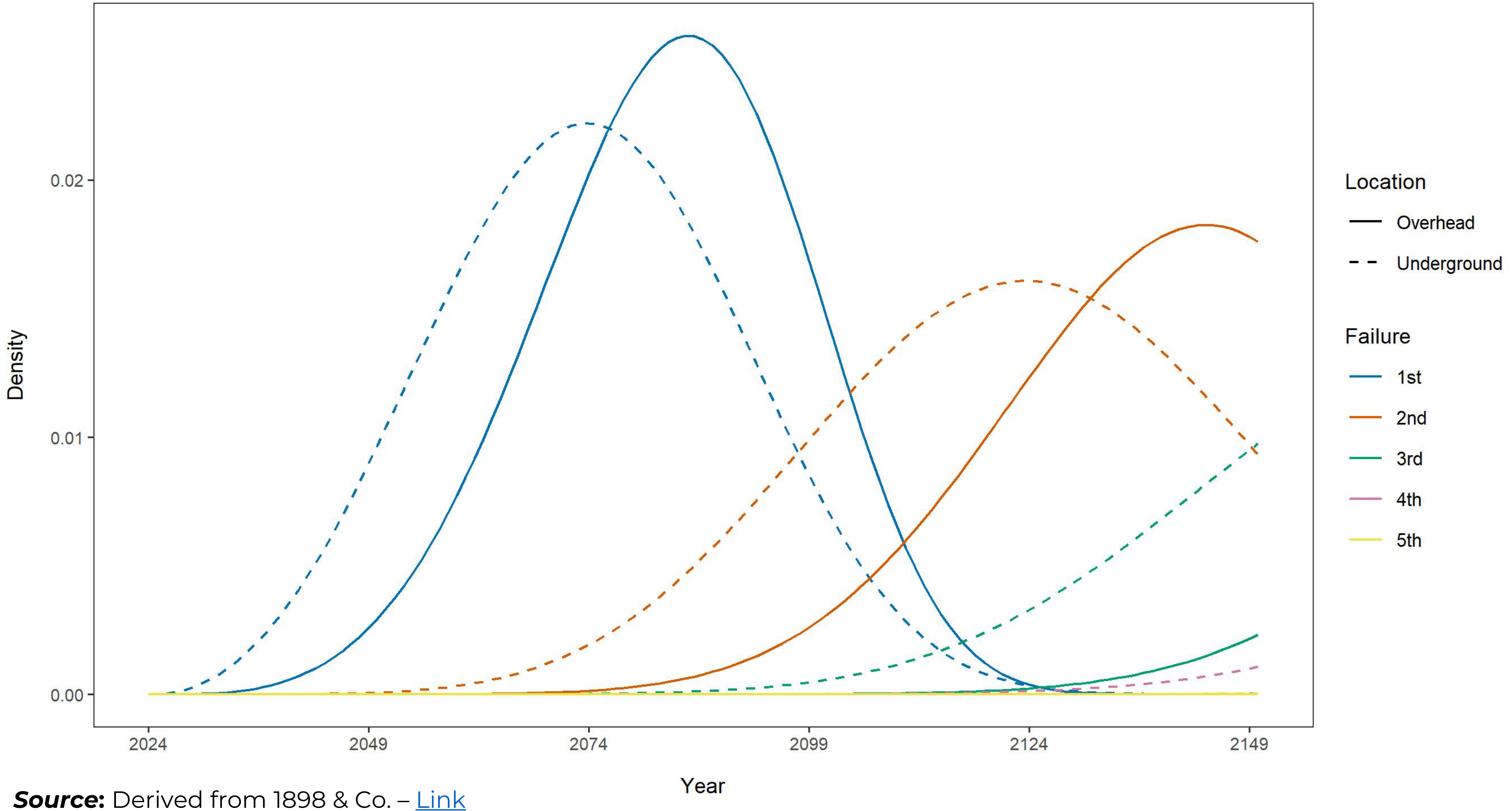
Failure probabilities are informed by 1898 & Co.'s undergrounding BCA for DTE Electric



Source: Derived from 1898 & Co. – Link

*****Underground is expected to fail earlier than overhead**

- Modeled via expected values of successive failures

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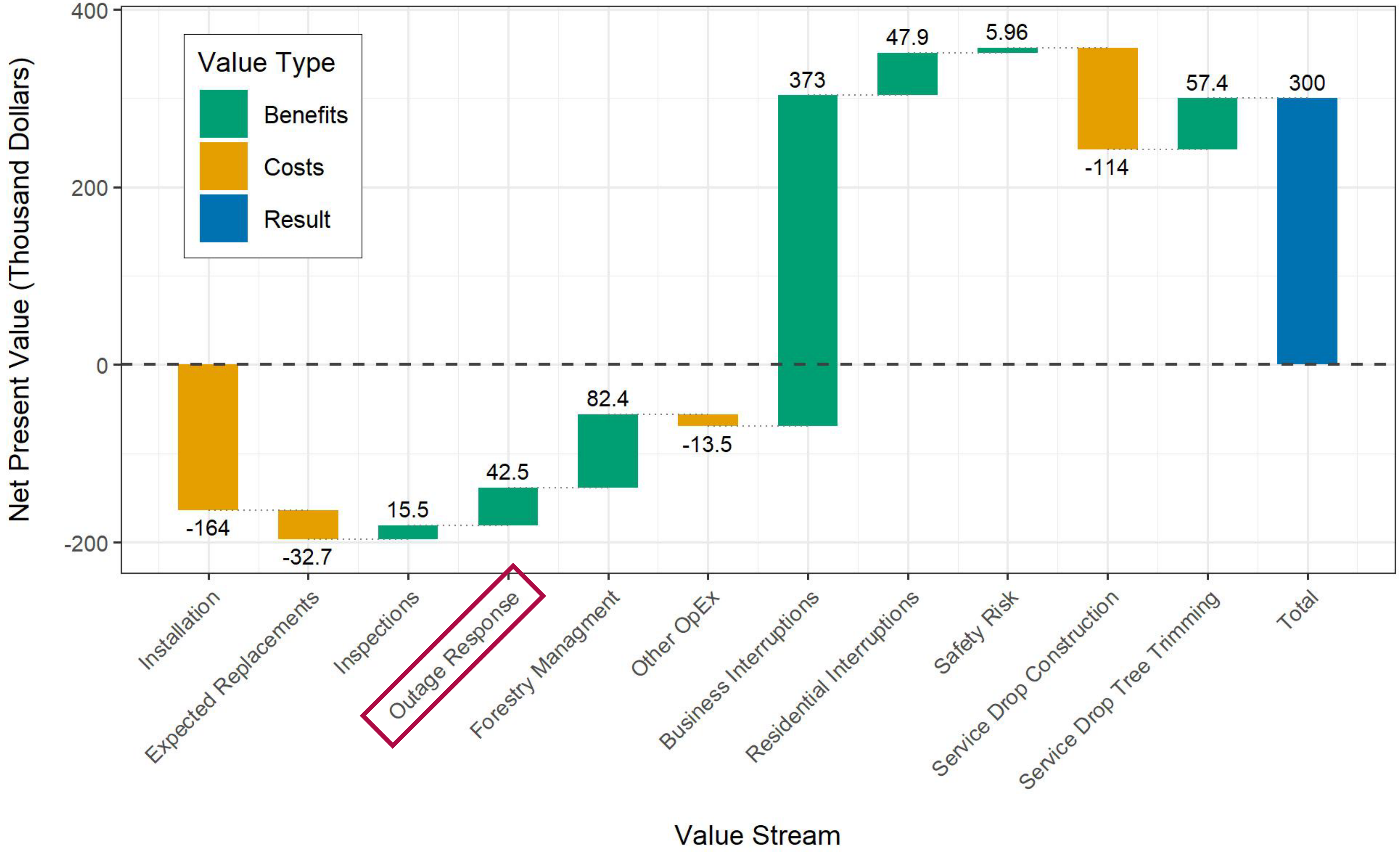
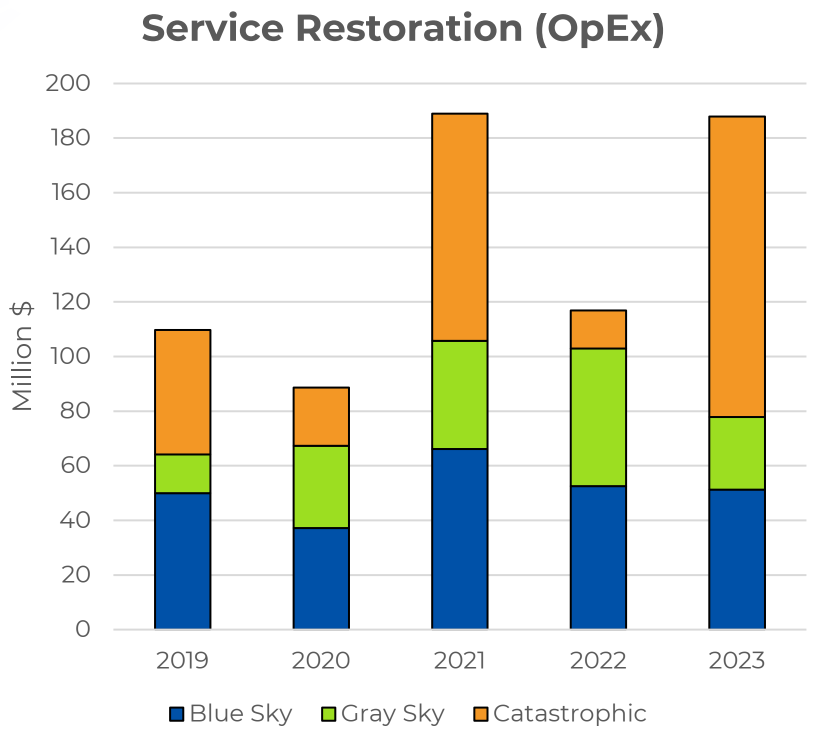
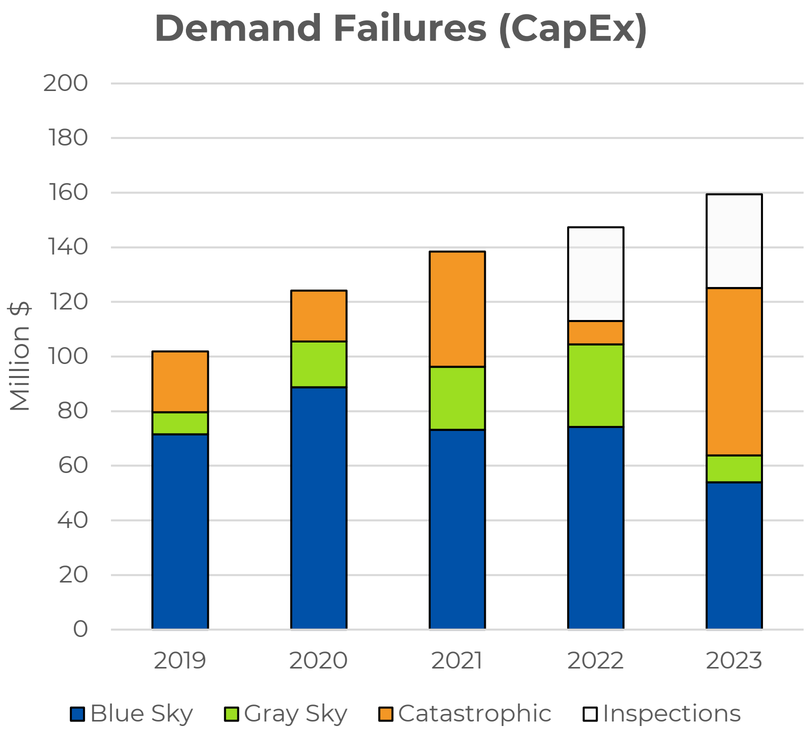

Value Type
Benefits
Costs
Result
Net Present Value (Thousand Dollars)
400
200
0
-200
-164
-32.7
15.5
42.5
82.4
-13.5
373
47.9
5.96
-114
57.4
300
Installation
Expected Replacements
Inspections
Outage Response
Forestry Managment
Other OpEx
Business Interruptions
Residential Interruptions
Safety Risk
Service Drop Construction
Service Drop Tree Trimming
Total
Value Stream

Outage response is modeled using historical spend from two programs and reliability metric projections





$ per customer minute interrupted (CMI) & $ per customer interruption (CI)

1. Unit costs per program (2) and outage condition (3)
2. Compute costs with future reliability data for both UG and OH scenarios
3. Average between CMI approach and CI approach

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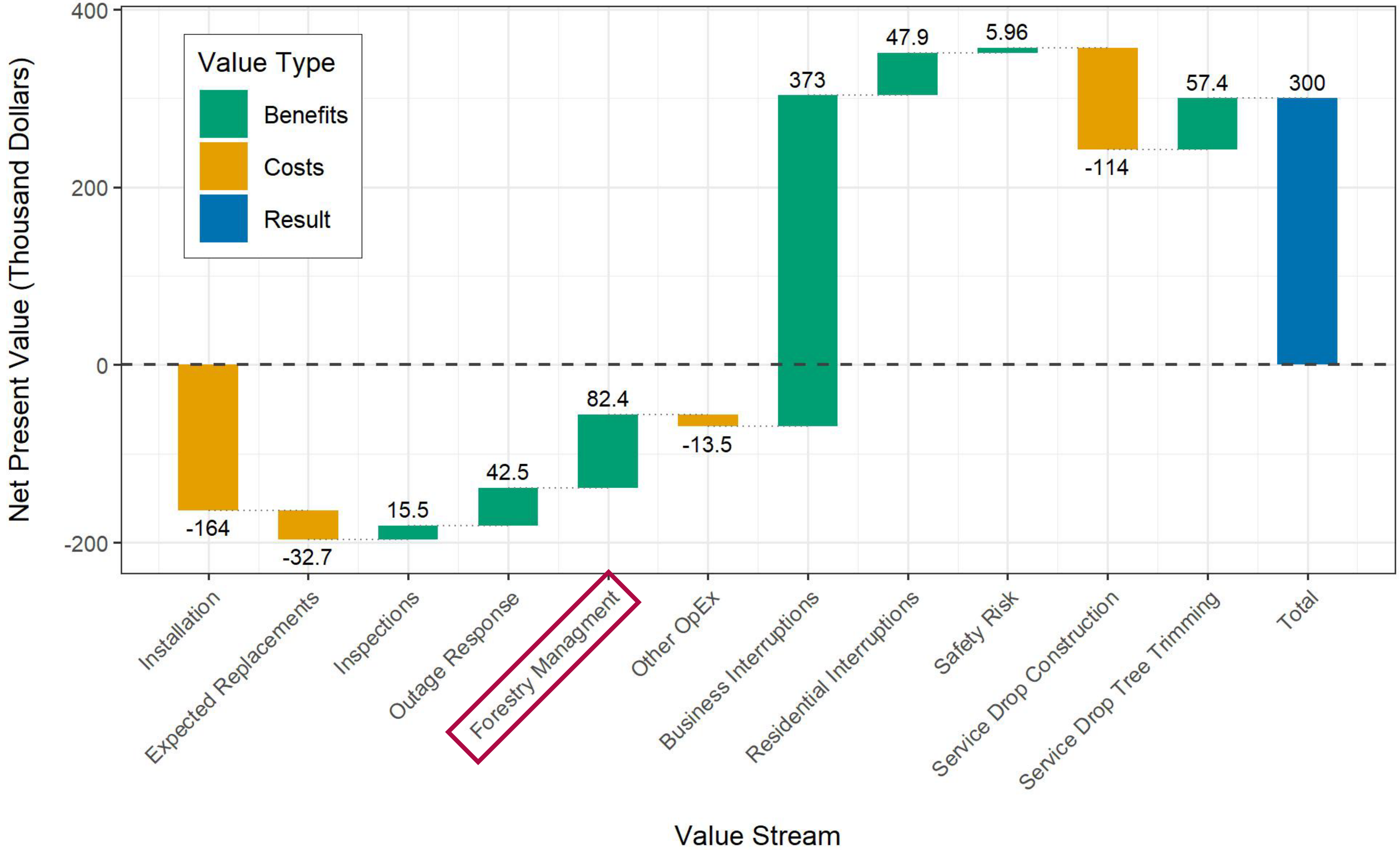
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Value Stream

Undergrounding avoids forestry management costs aligning with the 5-year effective cycle goal

Forestry management unit costs

Area Type	Infrastructure Location	Full System		5-Year Effective Cycle		Unit Costs	
		Overhead Miles	Trees	Annual Miles Trimmed	Annual Trees Trimmed	Per Mile	Per Tree
Urban	Backlot	1,881	178,399	375	35,107	$23,825	$222
	Frontlot	10,305	884,878	2,071	176,119	$14,267	$133
Rural	Backlot	7,451	830,129	1,578	175,498	$18,974	$177
	Frontlot	31,908	3,663,067	6,840	782,537	$14,267	$133
Total		51,545	5,556,473	10,864	1,169,261	$15,280	$142

$ per mile & per tree

1. Unit costs per area type (2) and infrastructure location (2)
2. Compute costs per effective (i.e., annualized using voltage cycles) mile and effective tree
3. Average between mile approach and tree approach

*** *Also, consider reliability benefits of the new 5-year effective cycle*

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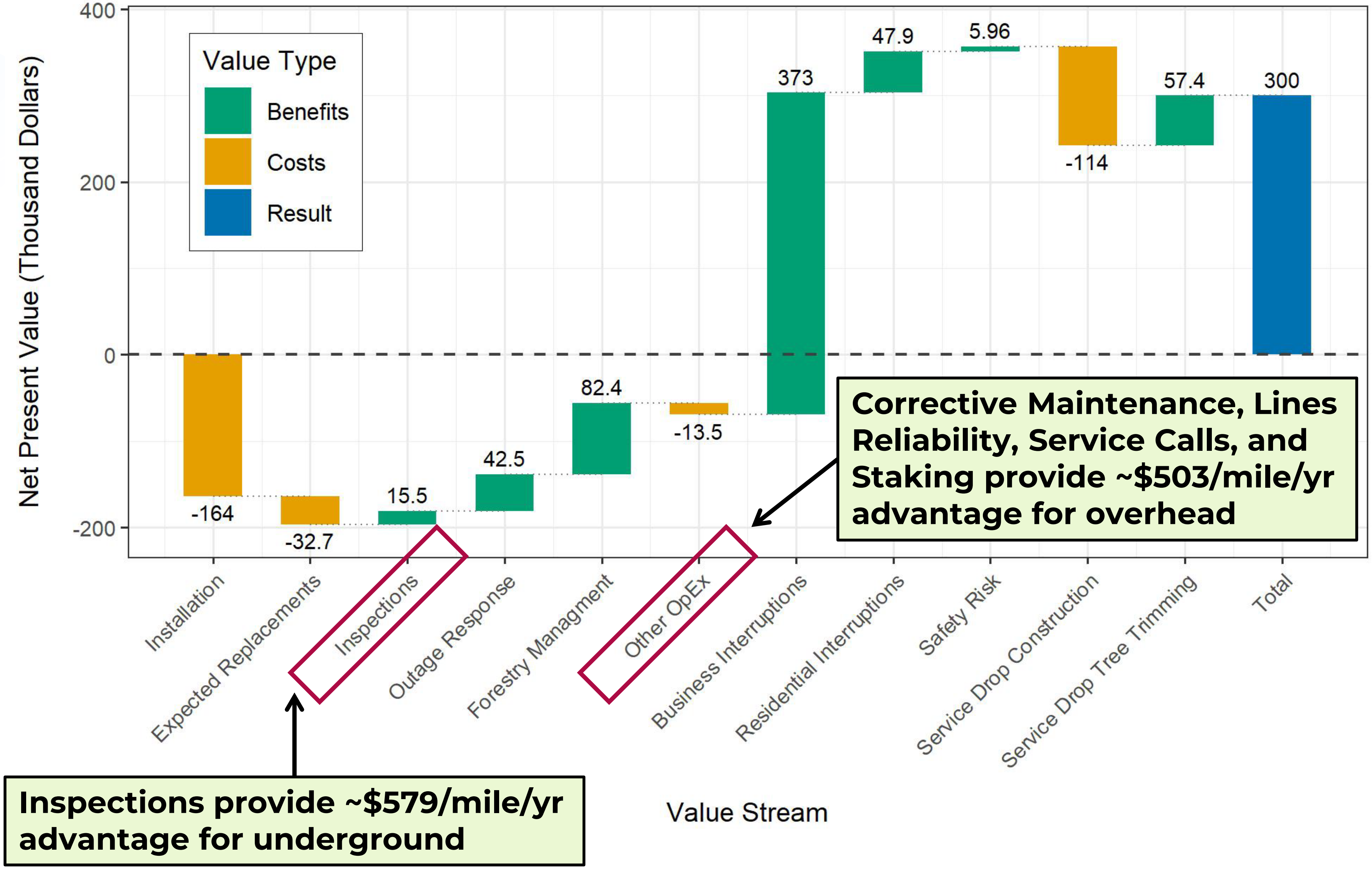
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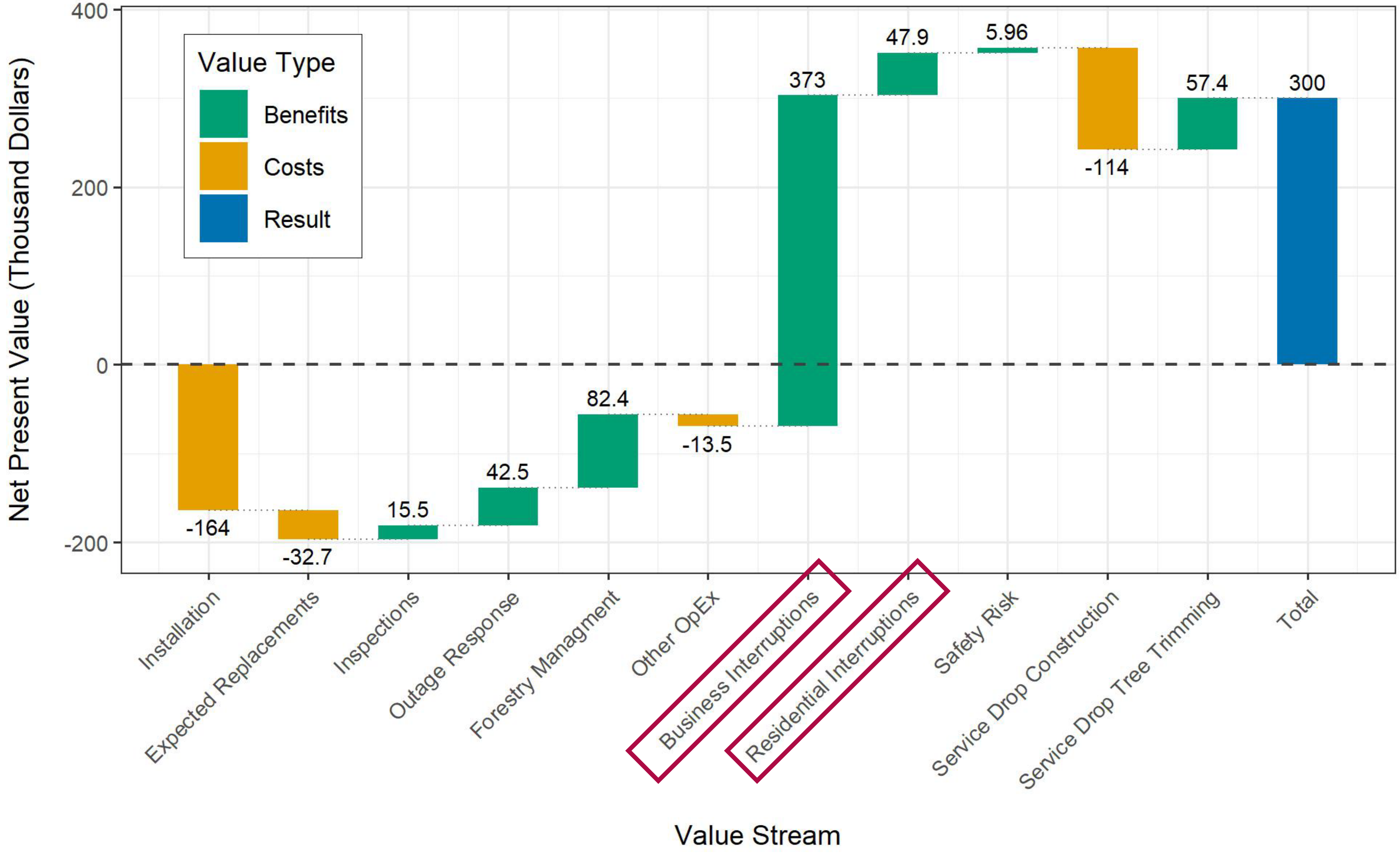
Total
Value Stream
Corrective Maintenance, Lines Reliability, Service Calls, and Staking provide ~$503/mile/yr advantage for overhead
Inspections provide ~$579/mile/yr advantage for underground



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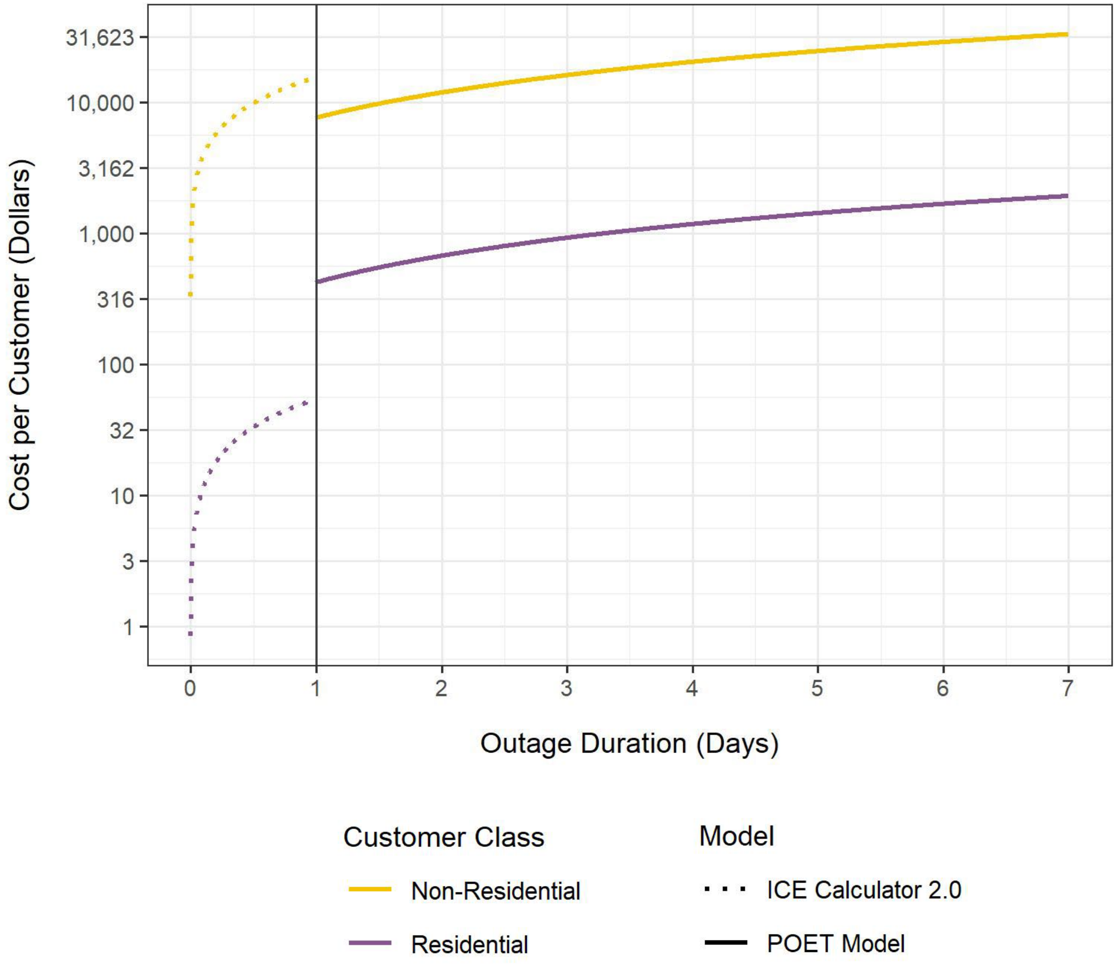
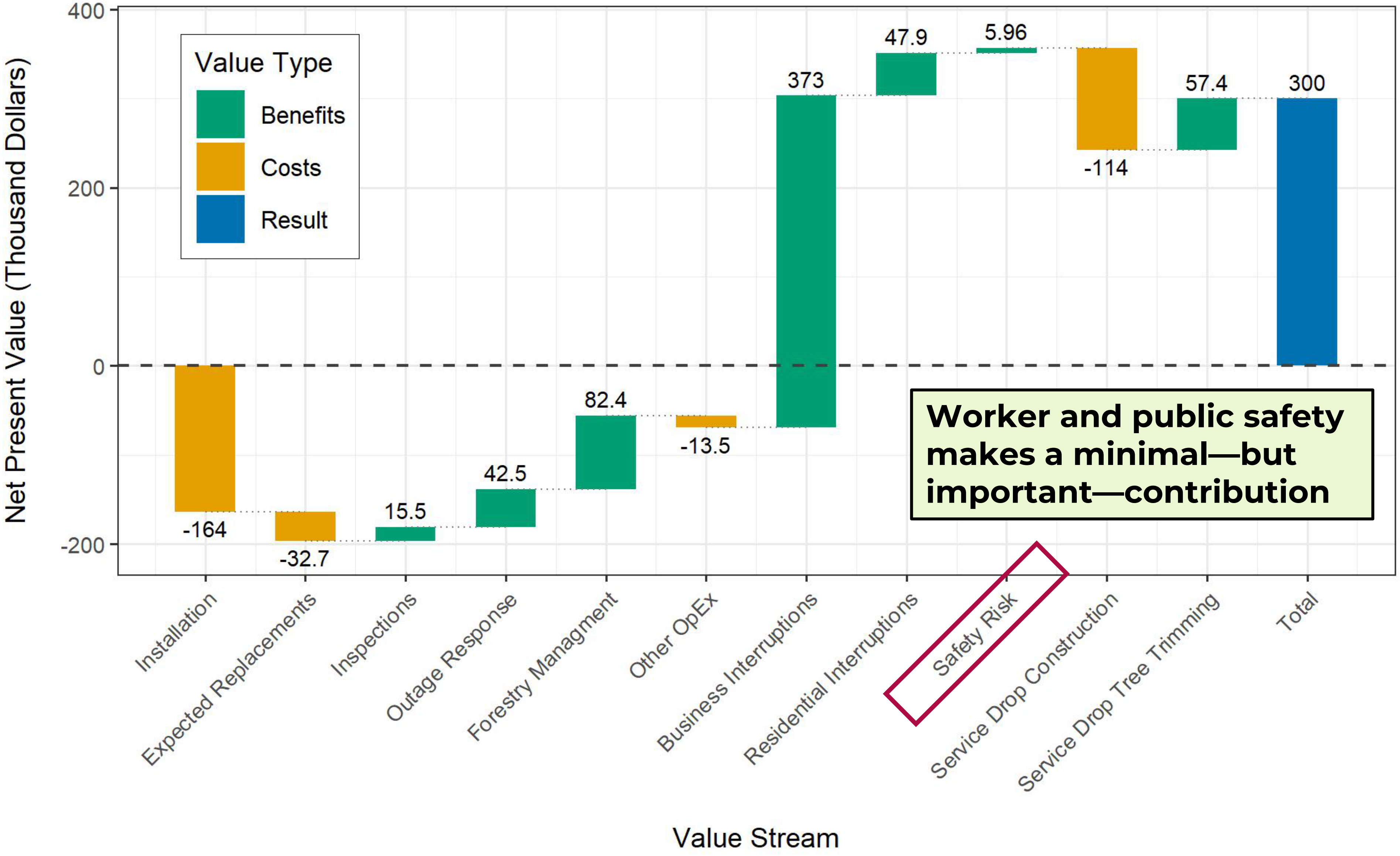
Interruption costs are modeled using valuation tools and reliability metric projections

- **Interruption Cost Estimate (ICE) Calculator 2.0** – Link
  - **Reliability** context; short-duration, minimally inconvenient events
  - Michigan-specific estimates
  - Applicable through 24 hours

- **Power Outage Economic Tool (POET) Model** – Link
  - **Resilience** context; widespread long-duration events
  - Prototype characterizes ComEd in Illinois—adapted here for Michigan
  - Applicable past 24 hours



Source: Derived from Larsen et al. (2025) and Larsen et al. (2024)



Worker and public safety makes a minimal—but important—contribution

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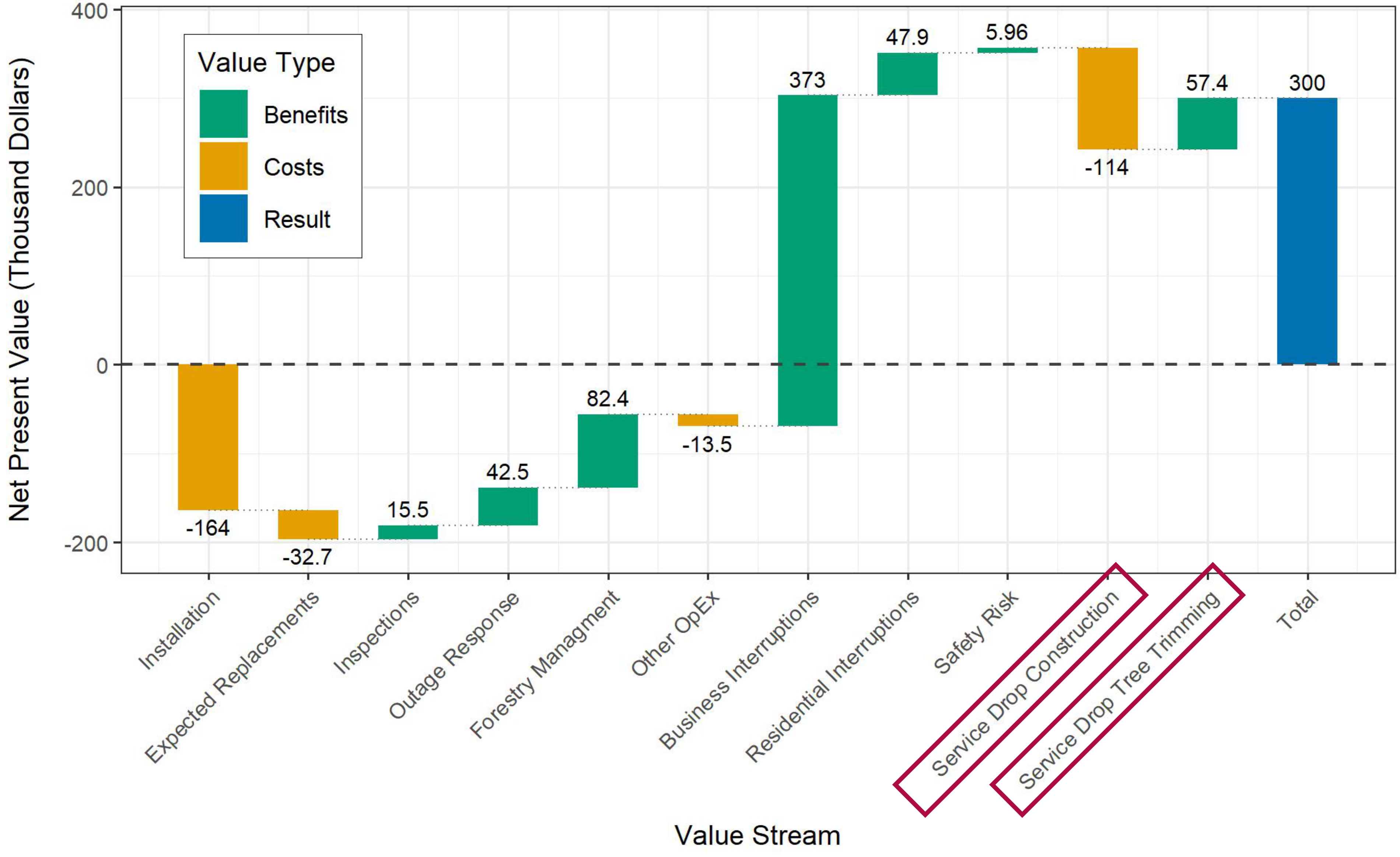
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Business Interruptions
Residential Interruptions
Safety Risk
Service Drop Construction
Service Drop Tree Trimming
Total
Value Stream

Service drops are a unique value stream because they can be optional and subject to cost sharing

- **Service drop installation**
  - At a ~$2,100 per customer premium (Tripolitis et al., 2015), undergrounding services increases total installation costs by more than 50% for the average circuit
  - Installing riser polls is an option to avoid these costs
  - Cost sharing may shift this from a utility expense to a customer expense
  - Importantly, associated benefits are entirely customer specific
- **Service drop tree trimming**
  - Tree trimming savings (~$300 every 6 years) go to customers, not the utility

Two tests: Primary Societal Cost Test (SCT) and secondary Utility Cost Test (UCT)

Primary SCT

- Installation
- Expected Replacements
- Inspections
- Outage Response
- Forestry Management
- Other OpEx
- Business Interruptions
- Residential Interruptions
- Safety Risk
- Service Drop Construction
- Service Drop Tree Trimming

Net Benefits = $300,000 per mile
Benefit-Cost Ratio = 1.9:1

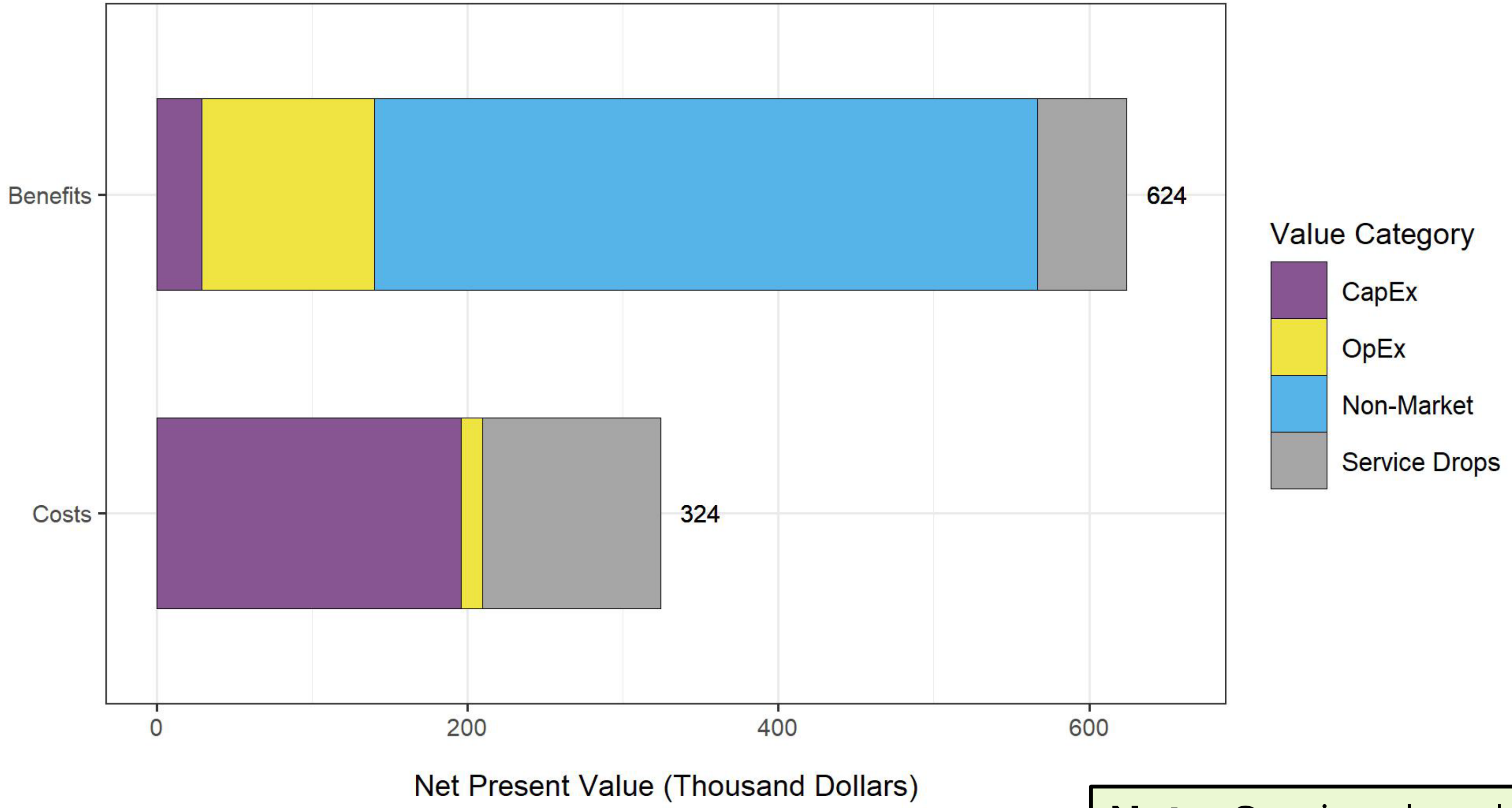
Secondary UCT

- Installation
- Expected Replacements
- Inspections
- Outage Response
- Forestry Management
- Other OpEx
- Business Interruptions
- Residential Interruptions
- Safety Risk
- Service Drop Construction
- Service Drop Tree Trimming

Net Benefits = -$69,300 per mile
Benefit-Cost Ratio = 0.7:1

4. Detailed findings

Benefits are primarily non-market values and OpEx while costs are primarily CapEx



Note: Service drop benefits are tree trimming (OpEx) while service drop costs are construction (CapEx)

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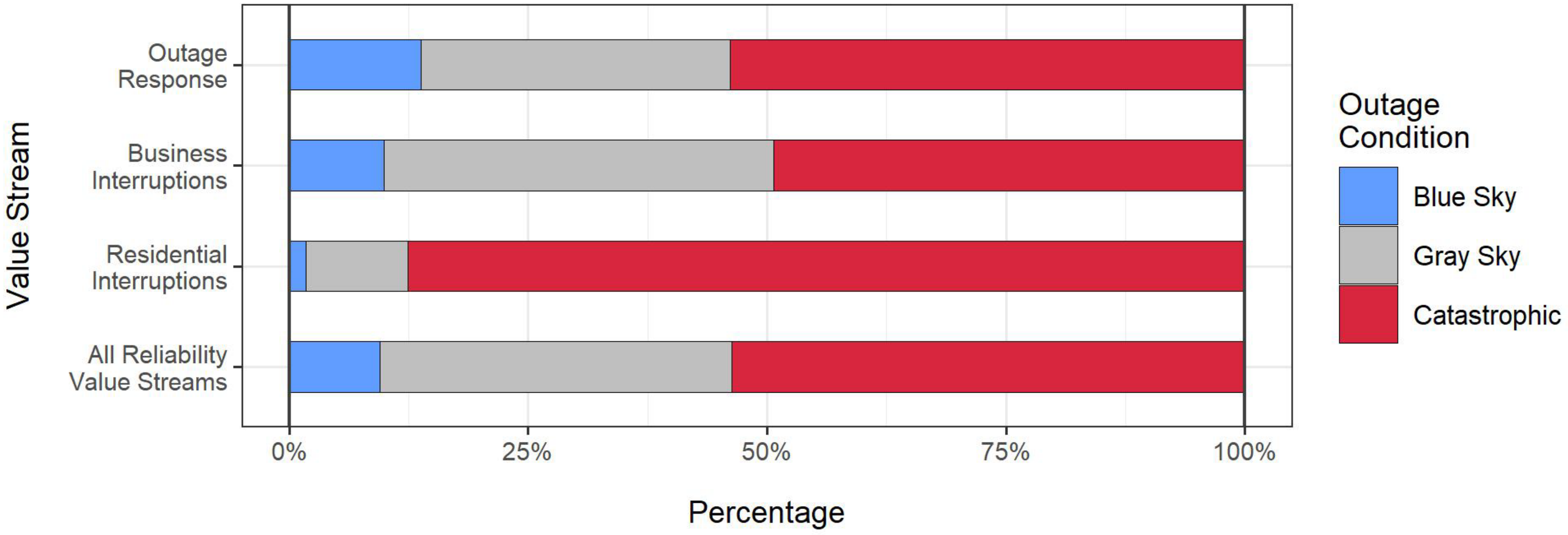
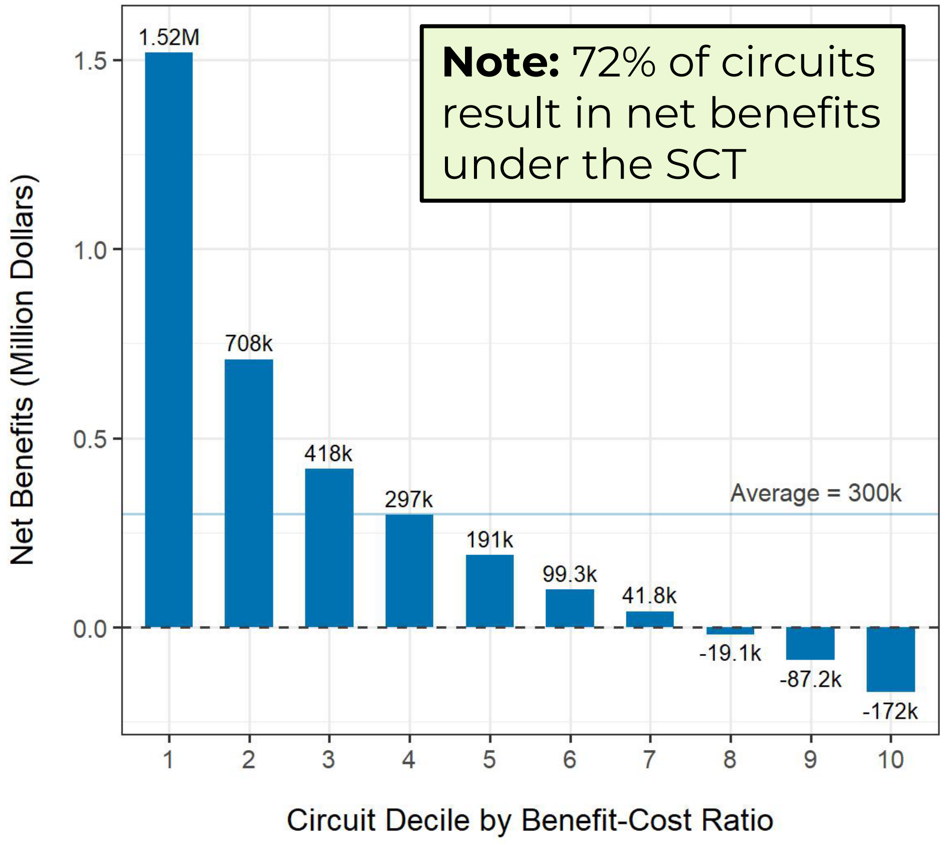
Benefits are dominated by reliability and resilience improvements during storms

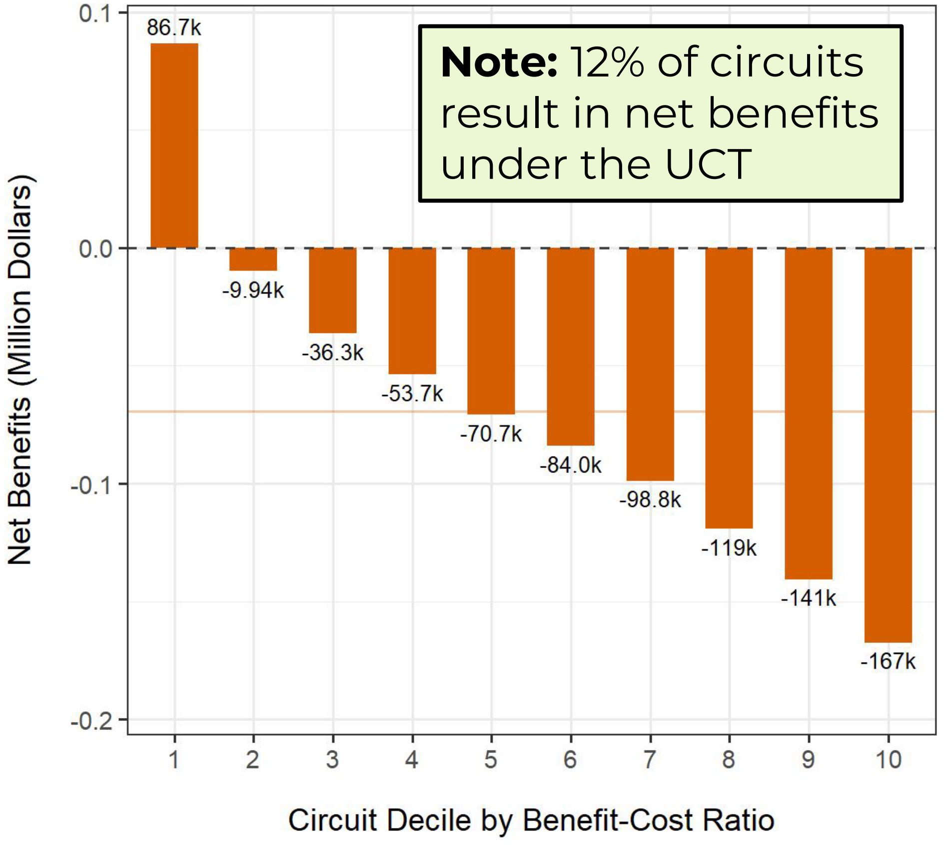
Note: 74% of benefits are tied to reliability and resilience improvements



The 10% most SCT cost-effective circuits yield net benefits of over $1.5 million per mile



Primary SCT



Secondary UCT

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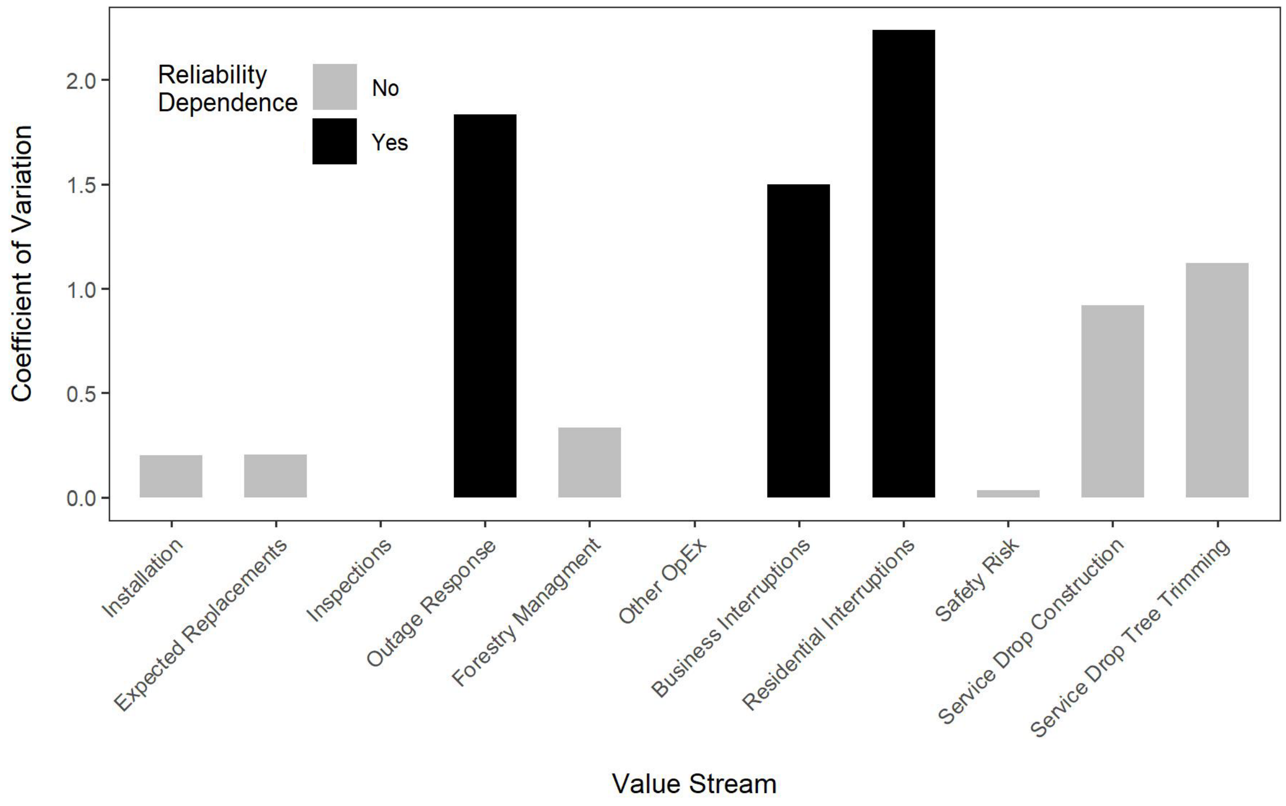
Circuit variation is dominated by the reliability value streams, particularly business interruptions

- Among **value streams**, business interruption costs account for over 80% of the variation among circuits

- Among **circuit characteristics** gray sky and catastrophic SAIFI explain 35% of the variation
  - Customer density explains another 15% of variation
  - No other variable explains more than 2% of variation



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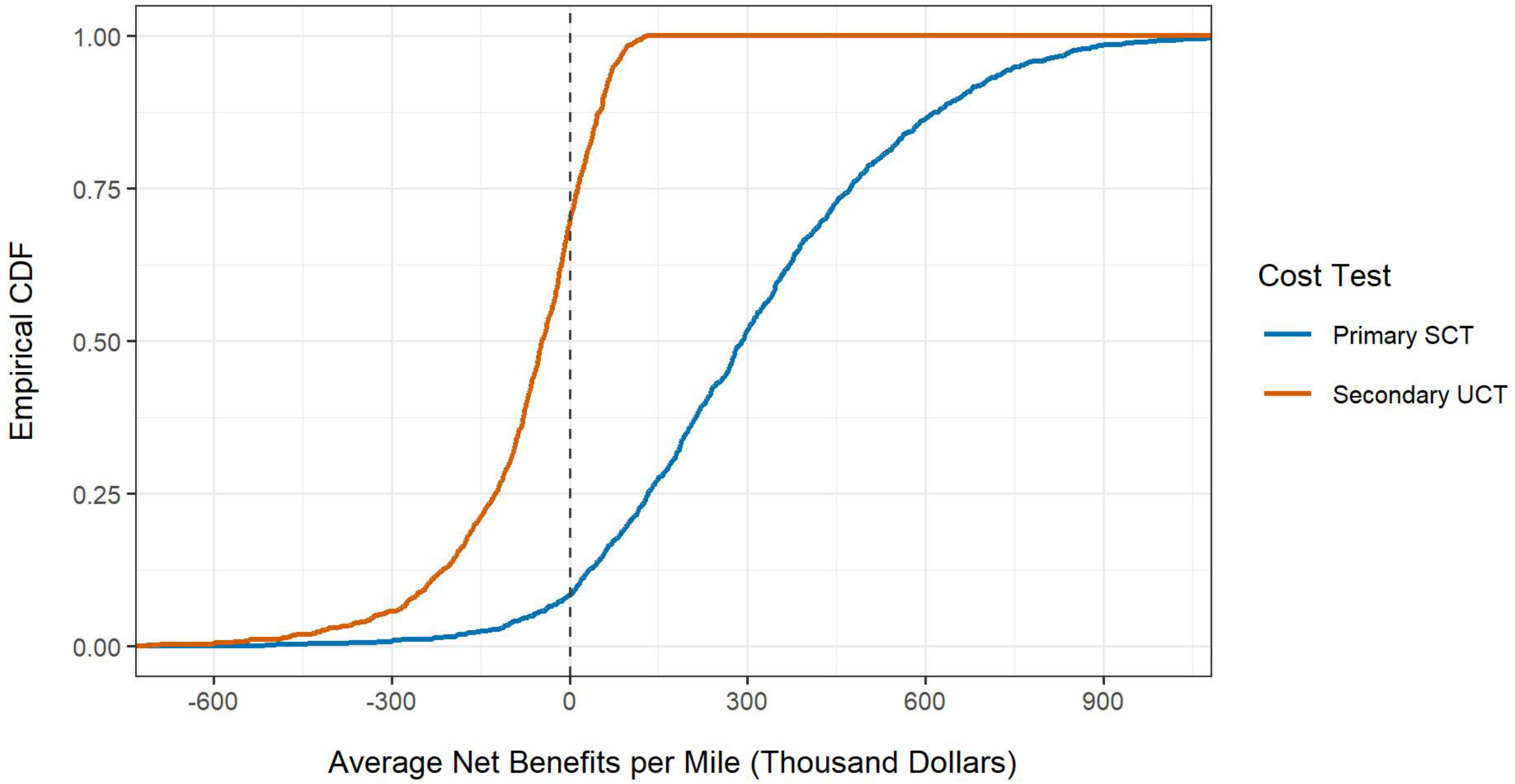
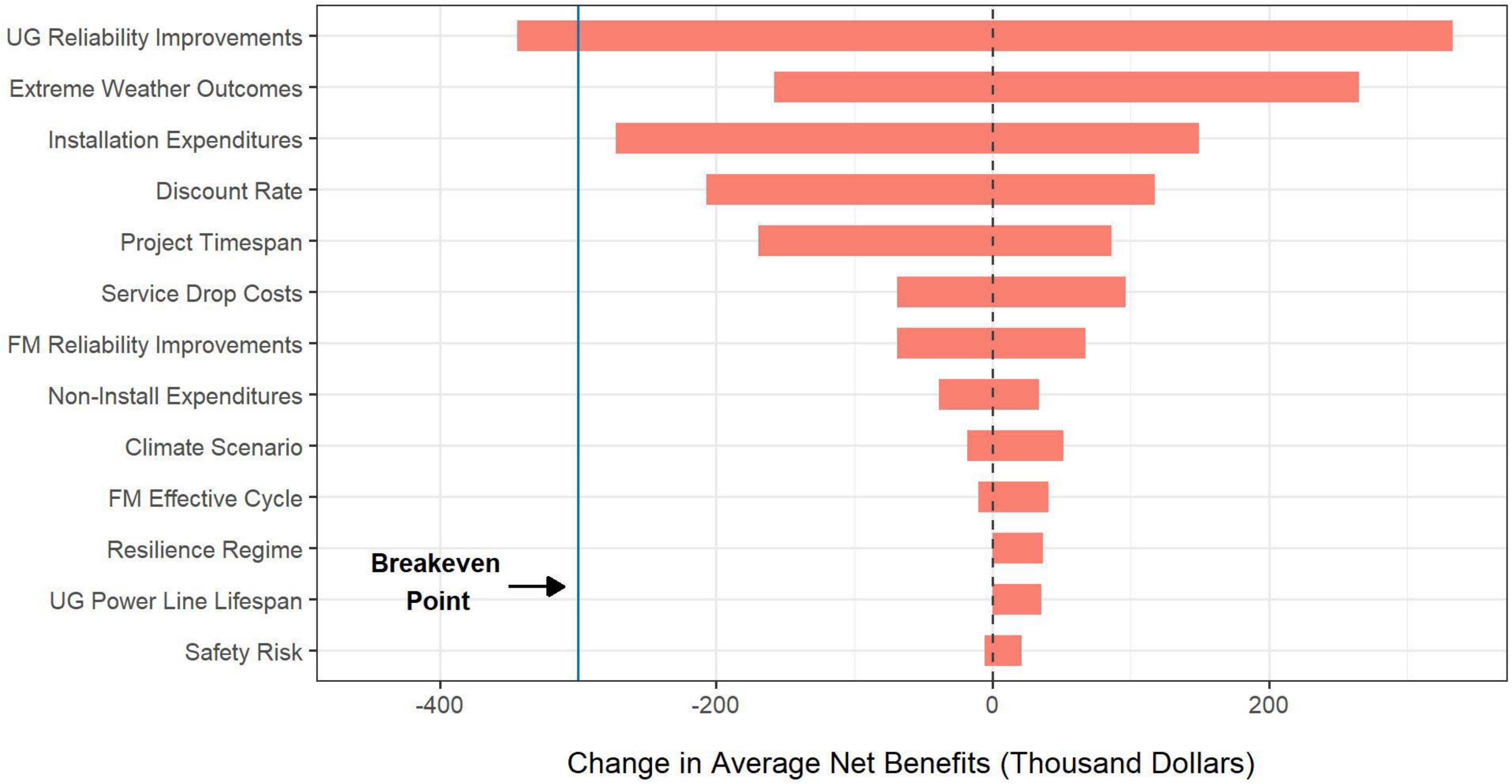
Average net benefits per mile are positive in 92% of uncertainty simulations under the primary SCT



Note: Average net benefits per mile are positive in 31% of uncertainty simulations under the secondary UCT

Results are most sensitive to reliability gains, extreme weather outcomes, and installation costs



Note: UG = Underground; FM = Forestry Management

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Selecting projects optimally yields a major advantage for cost-effectiveness

35-Mile Portfolio (35 Unique Circuits)		Benefits (Million $)	Costs (Million $)	Net Benefits		Benefit-Cost Ratio
				Total (Million $)	Per Mile (Thousand $)	
1	Highest BCR: SCT	111 (13.3)	13.2 (6.98)	98.3 (6.33)	2,810 (181)	8.45 (1.91)
2	Highest BCR: UCT	115 (16.2)	17.4 (7.54)	97.5 (8.64)	2,790 (247)	6.61 (2.15)
3	Random	19.0 (4.94)	10.0 (7.06)	8.98 (-2.12)	256 (-60.7)	1.89 (0.70)
4	Highest Storm SAIFI	80.5 (11.6)	10.8 (6.59)	69.7 (5.05)	1,990 (144)	7.47 (1.77)
5	Highest Customer Density	81.4 (11.8)	26.7 (8.81)	54.8 (2.97)	1,560 (85.0)	3.05 (1.34)

Note: First value characterizes SCT; second value in parentheses characterizes UCT

Key Takeaways:

- Choosing projects based on modeled outcomes can yields net benefits 10x those of a random portfolio
- Sacrificing some SCT net benefits to maximize UCT net benefits still yields strong outcomes
- Prioritizing based on historical storm SAIFI is the strongest proxy variable approach, but net benefits are still 29% lower than when optimizing via modeled outcomes

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5. Conclusions

So, does strategic undergrounding make sense? This study's results suggest it does

- Converting overhead lines to underground is economically viable for the CE service territory, with average **net benefits of $300,000 per mile and a BCR of 1.9**
- The most cost-effective projects are found in areas with high storm-related outages and dense customer bases, with the **top 10% of circuits yielding net benefits of $1.5 million per mile and a BCR of 5.3**
  - A targeted 35-mile portfolio could achieve net benefits of $98 million at a BCR of 8.5
- While this study suggests undergrounding is a sound strategy, its **cost-effectiveness is highly dependent on context**, and the framework used here should consider unique conditions if adapted by other utilities
- There are several **limitations**, including the model's circuit-level resolution, its simplification of infrastructure age, and its inability to quantify all potential benefits and costs, like **aesthetic benefits and wildfire risk reduction**

Thank you! Questions?

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U.S. Department of Energy Fellow (Energy Innovator Fellowship)

Washington, D.C.

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How to Manage Risk on a Budget

Tools and frameworks for addressing safety, affordability, and equity

9/19/25

Eric Borden
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eborden@synapse-energy.com

Synapse Energy Economics

- Founded in 1996 by CEO Bruce Biewald
- Leader for public interest and government clients in providing rigorous analysis of the electric power and natural gas sectors
- Staff of 40+ includes experts in energy, economic, and environmental topics

Agenda

- Overall framework for how to address affordability in the context of safety investments
- Risk in context
  - Example: Minnesota state and utility wildfire risk in context
- Examining options to address risk in cost-efficient manner for wildfire expenditures in California
  - Example 1: Southern California Edison
  - Example 2: San Diego Gas and Electric

Overall Framework for Assessing Safety and Affordability

Three key elements:

1) Robust benefit-cost analysis (BCA) based on granular risk modeling. Inputs and outputs can be utilized to a) *prioritize investment* from highest to lowest risk areas/infrastructure, and b) *assess tradeoffs,* if any, between safety and affordability.

2) Recognition that ratepayers have finite resources. The goal should be to achieve <u>the maximum amount of risk reduction for each ratepayer dollar spent</u>, ideally within an overall budget constraint that also considers other priorities and expenditures.
   - This can be done by evaluating risk in context and all options to address risk (e.g. undergrounding vs. alternatives) to examine benefits and costs.
   - The examples to follow from Minnesota and California provide illustrations of this.

3) Equity issues should be considered and/or incorporated into the BCA. For example, vulnerable communities may not be adequately represented in a typical BCA.

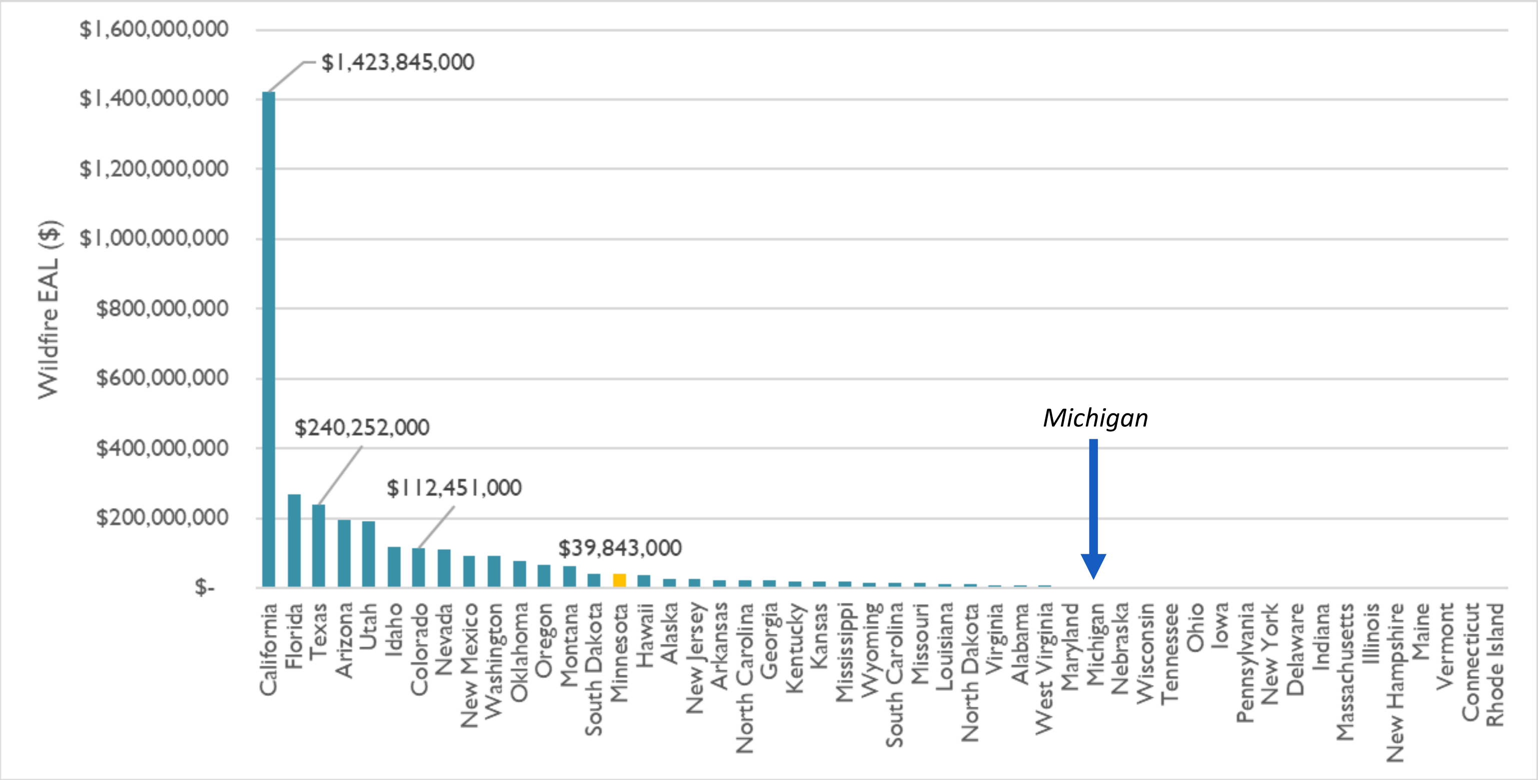
Putting Risk in Context to Maximize Benefits and Minimize Costs

Wildfire risk in Minnesota compared to other states

Minnesota's wildfire risk is modest compared to other states.

- Fourteen states have higher wildfire risk than Minnesota in terms of Expected Annual Loss (EAL), FEMA's calculation of risk.
- California has around 36 times more wildfire risk than Minnesota and 272 times more wildfire risk as Michigan

Wildfire Risk by State ($ 2022)

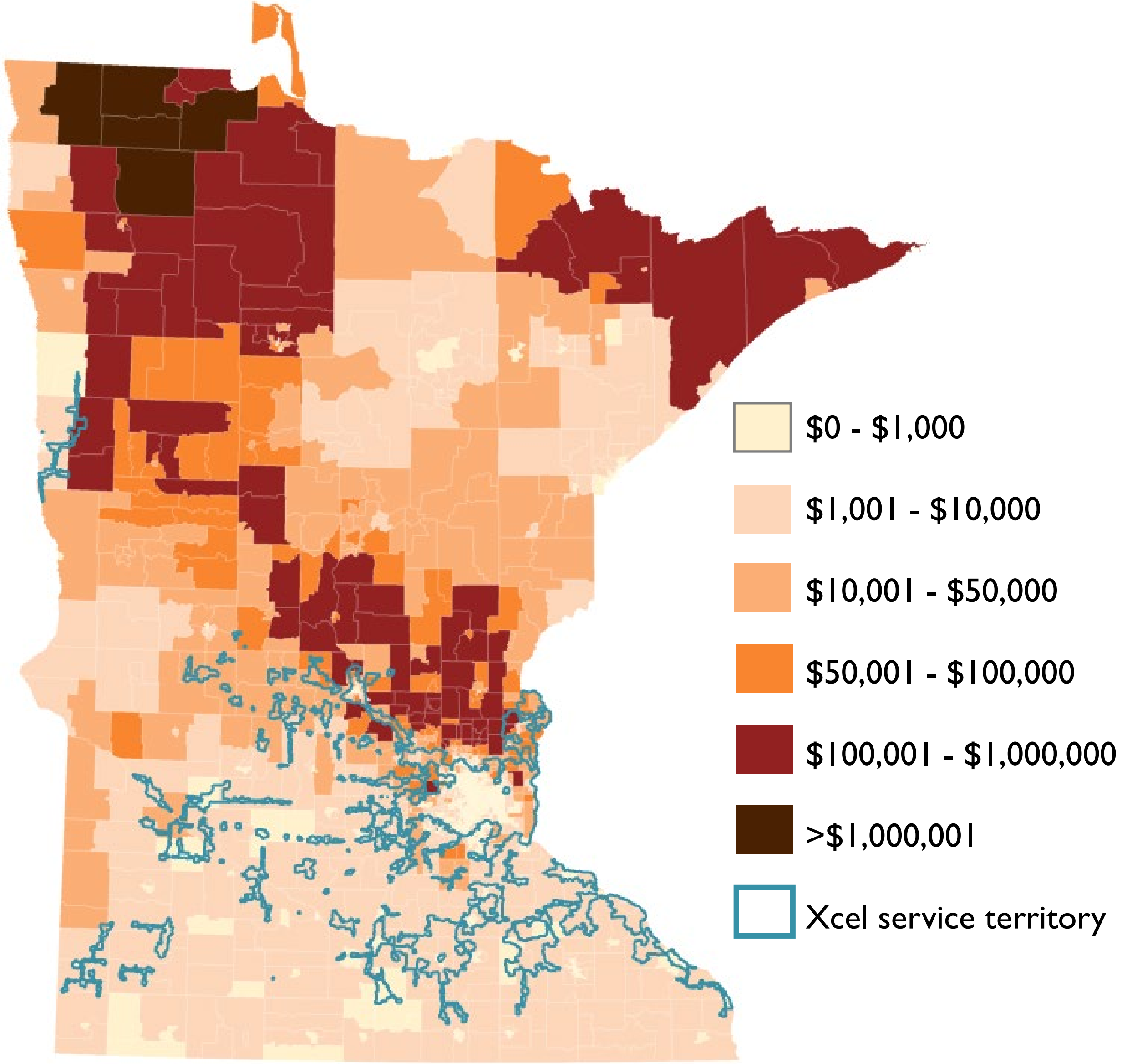


Source: FEMA, 2025. Data Resources. Available at Data Resources | National Risk Index

Wildfire Risk in Minnesota and Xcel MN Territory

State and societal risks should be addressed holistically

- Risk varies significantly across Minnesota.
- Other parts of the state contain most of the wildfire risk.

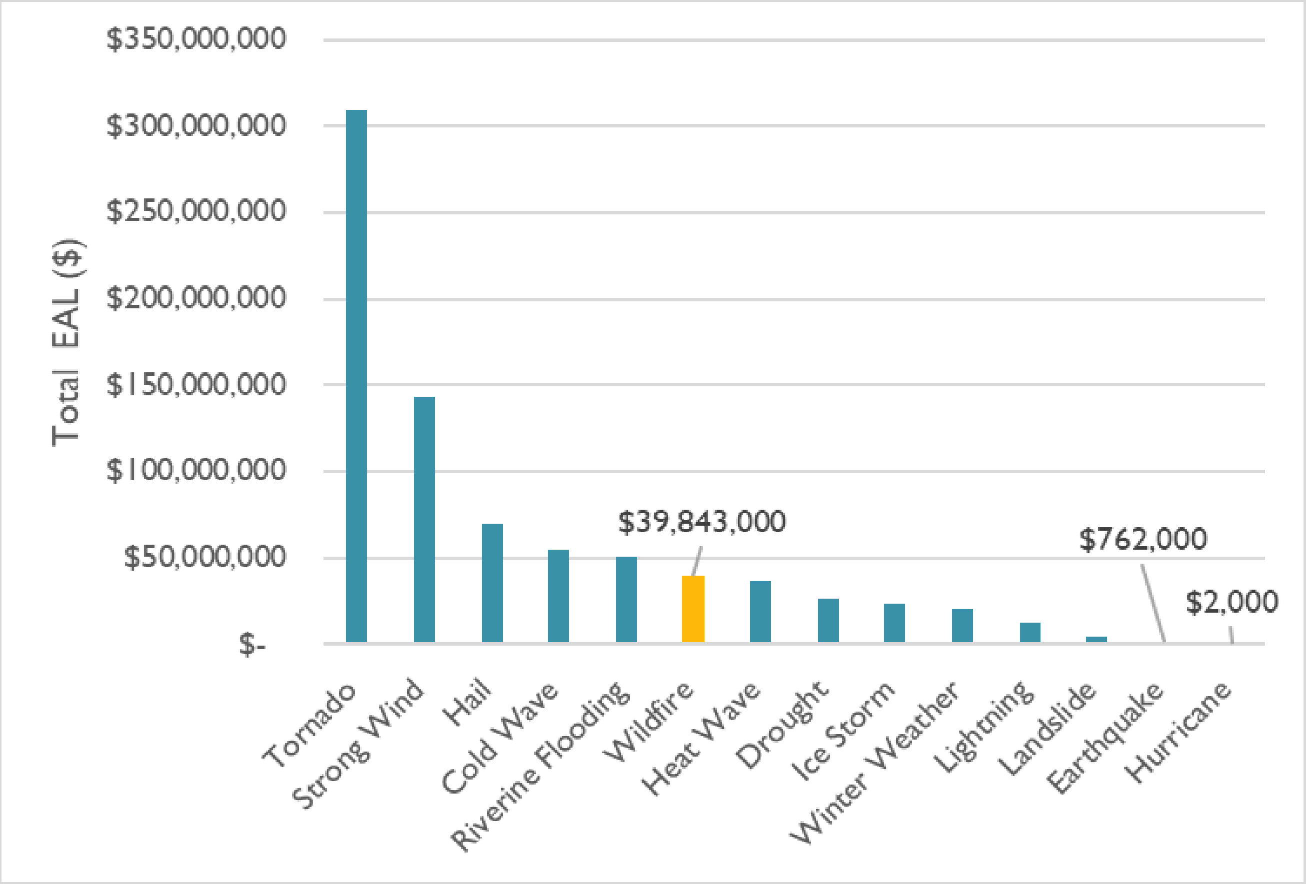


Wildfire risk in Minnesota compared to other risks

Wildfire is not the top risk in Minnesota.

- Ratepayers have finite resources to address a multitude of priorities.
- Risk data from FEMA indicates that wildfire is the sixth most pressing risk facing Minnesota.
- It likely that wildfire is not Xcel MN's top risk, either.

Risk by Hazard in Minnesota (2022 $)

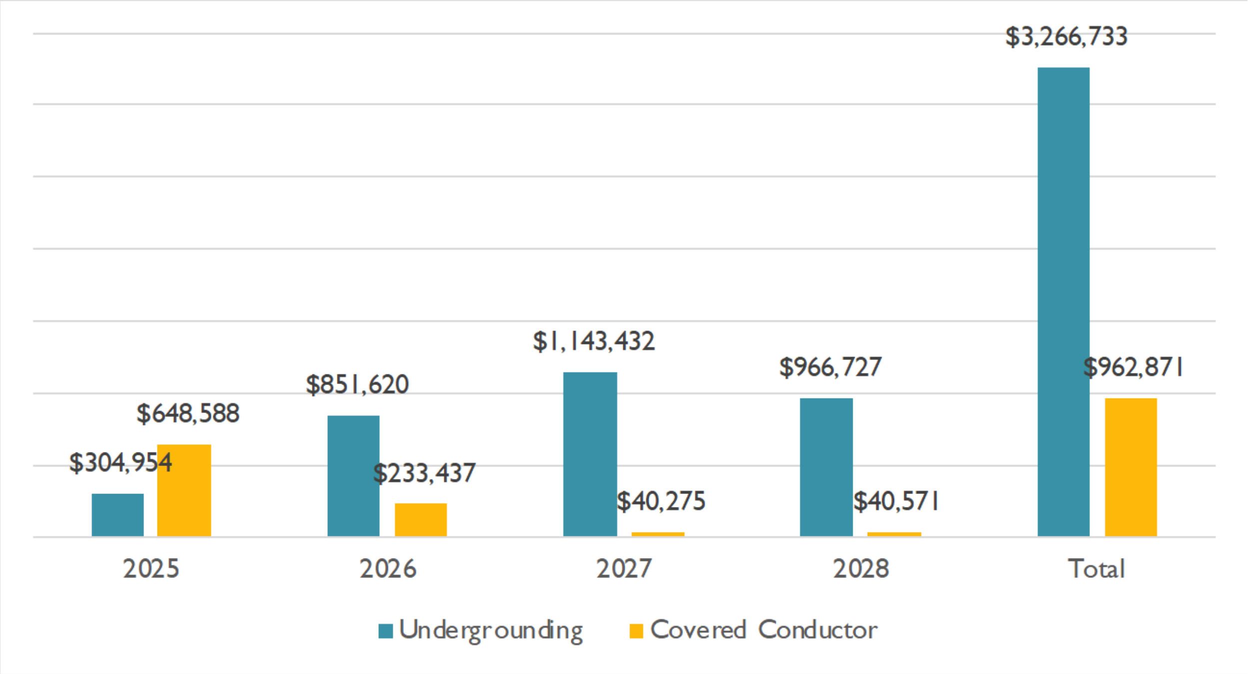


Source: FEMA, 2025. Data Resources. Available at [Data Resources | National Risk Index]

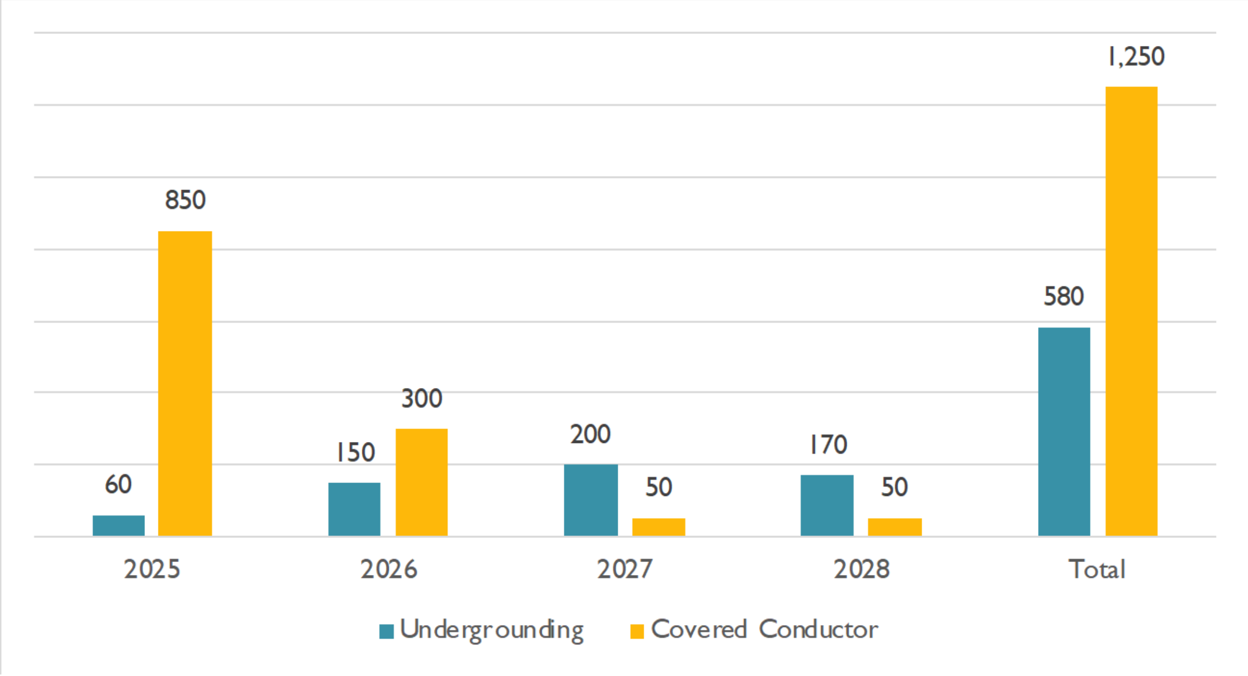
Undergrounding and Affordability in California

Example: Southern California Edison (SCE) Background

SCE Forecast Grid Hardening Costs ($ Thousands)



SCE Forecast Grid Hardening Overhead Miles



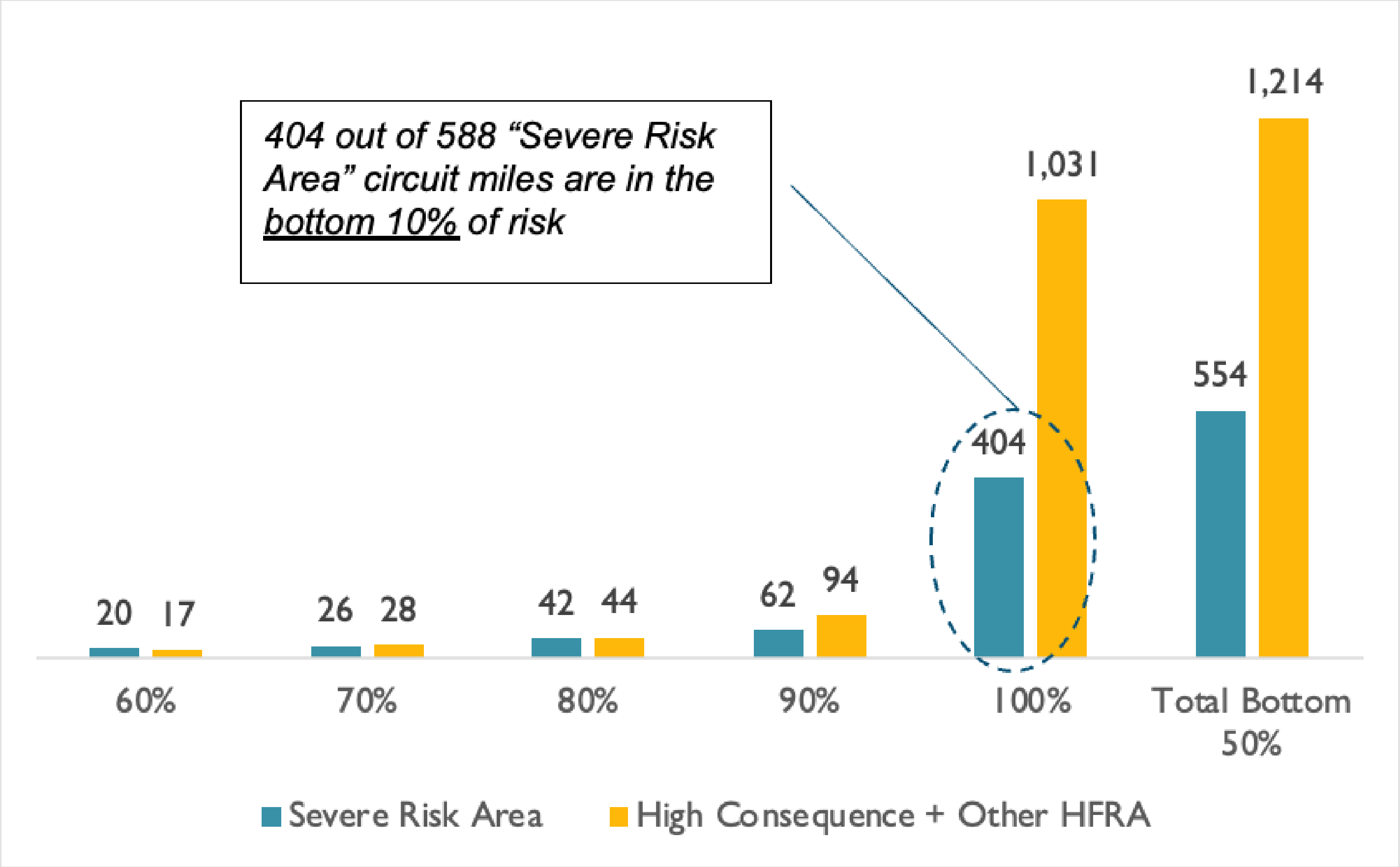
- SCE proposed to underground overhead miles in “Severe Risk Areas” (SCE’s term).
- These criteria were qualitative – we found most or all of them were already captured in SCE’s quantitative risk modeling or did not necessarily lead to the conclusion that undergrounding is always the best alternative.

Example: Southern California Edison (SCE) Analysis of SCE Proposal

Nearly 70 percent of proposed underground miles are in the bottom 10 percent of risk

- The x-axis shows circuit miles which according to SCE's risk model results, are in the bottom 50 percent of risk in its service territory when ranked from highest to lowest risk

Circuit Miles in Bottom 50 Percent of Risk



Example: Southern California Edison (SCE) Analysis of Prior Risk Reduction

Billions of ratepayer dollars spent on covered conductor, plus line settings to shut off power, reduced risk by nearly 75 percent before the rate case

- SCE had already achieved a large amount of risk reduction through deployment of covered conductor throughout its high fire risk area and line settings that shut off power more quickly during extreme weather conditions.

- This means subsequent investment is expected to be less cost-effective. If SCE deployed its mitigations from highest to lowest risk, it is also addressing less risky portions of the service territory.

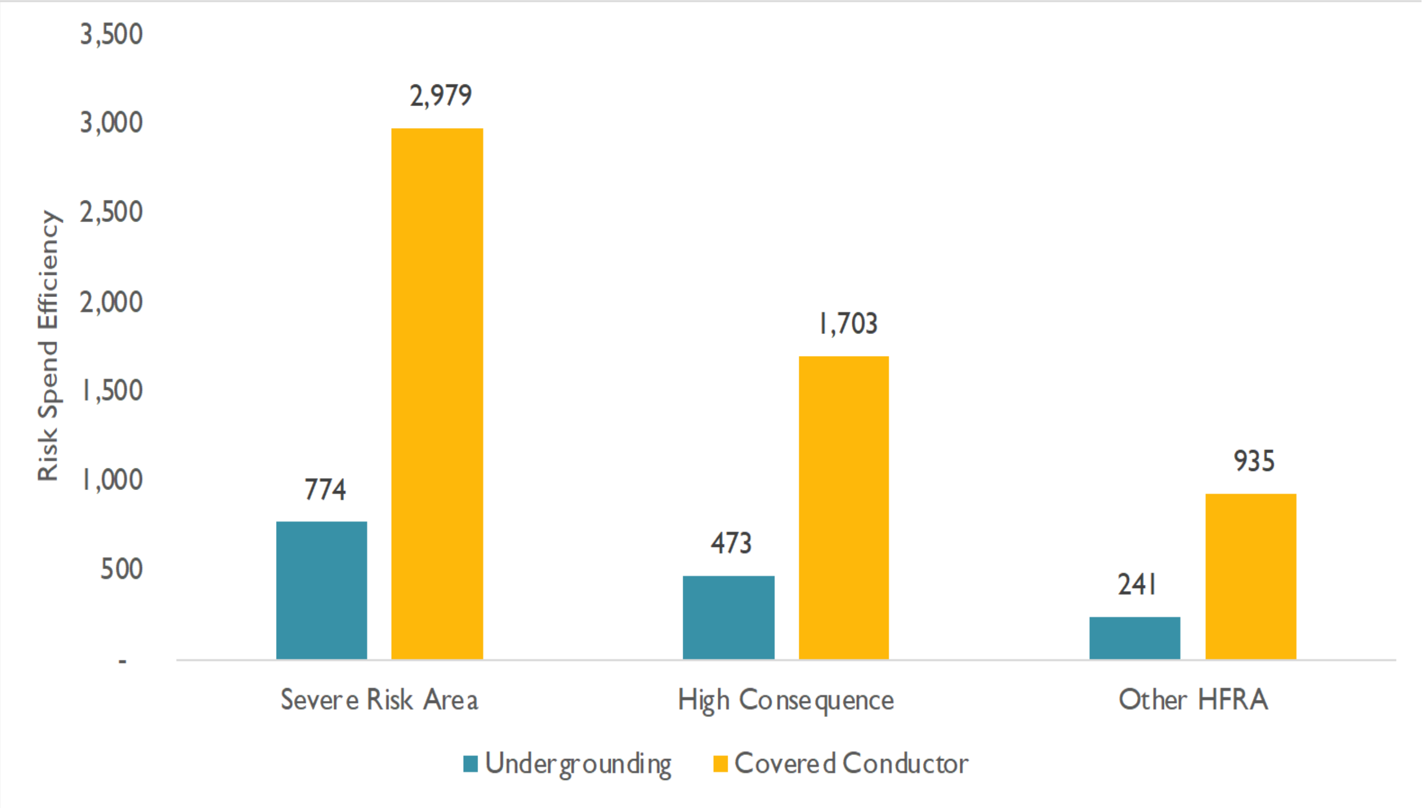
Wildfire Risk Remaining After Grid Hardening and Fast Curve Settings (2018-2024)

Example: Southern California Edison (SCE) Analysis of Cost-effectiveness

Covered conductor is significantly more cost-effective than undergrounding

- Covered conductor is significantly more cost-effective than undergrounding, meaning each dollar of expenditures achieves more risk reduction relative to undergrounding.
- However, undergrounding provides higher absolute benefits (risk reduction) when comparing alternatives for the same project.

Cost-effectiveness of Undergrounding vs. Covered Conductor

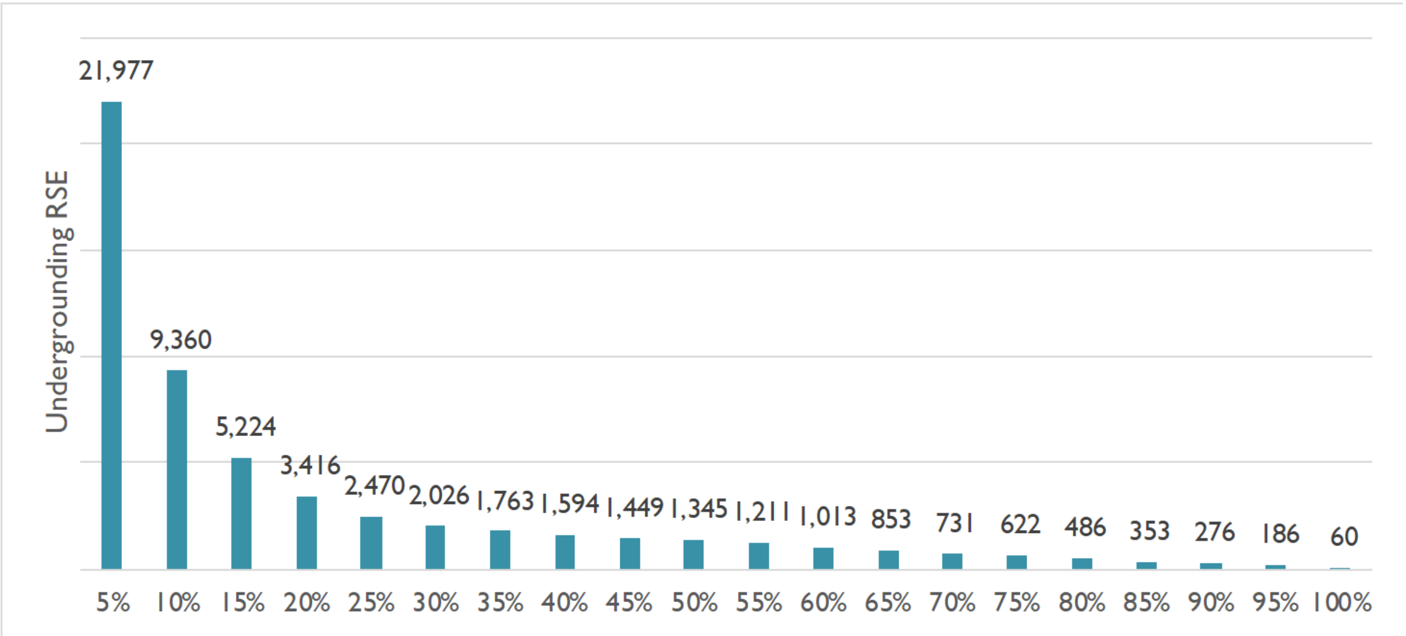


Example: Southern California Edison (SCE) Analysis of Undergrounding Cost-effectiveness

Undergrounding cost-effectiveness has diminishing returns as projects address lower-risk areas

- We examined risk concentration, risk per mile, and cost-effectiveness for undergrounding across remaining miles in SCE's service territory.
- We noted that risk reduction from undergrounding expenditures significantly decrease once the top 50 percent of risk is reached.
- Based on this, we took a very cautious approach by recommending this top 50 percent be undergrounded, equivalent to 177 miles.

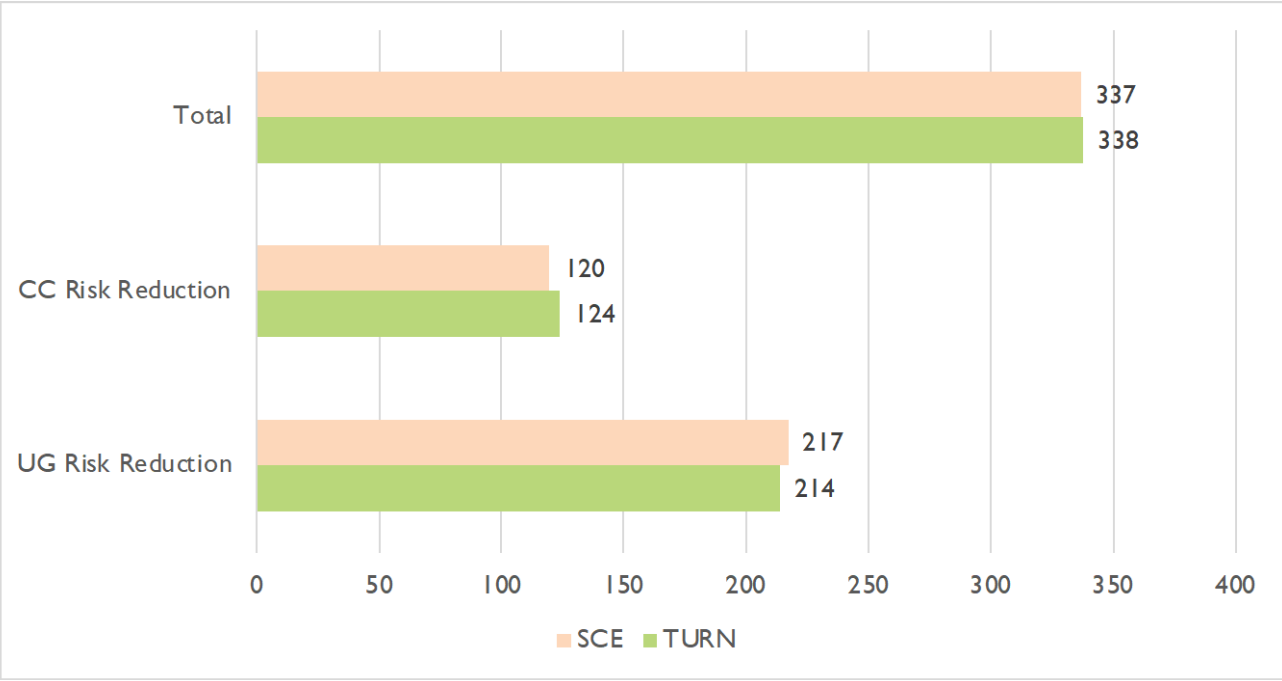
Cost-effectiveness of Undergrounding



Example: Southern California Edison (SCE) Synapse/TURN Proposal

- We proposed significantly less undergrounding than SCE (177 vs. 580 miles) but more miles of covered conductor (1,651 vs. 1,250).
- By focusing on only the highest risk circuits, we dramatically reduce risk.
- The risk reduction of these proposals is equal, and would save ratepayers **$2 billion**.

Risk Reduction of Grid Hardening Proposals



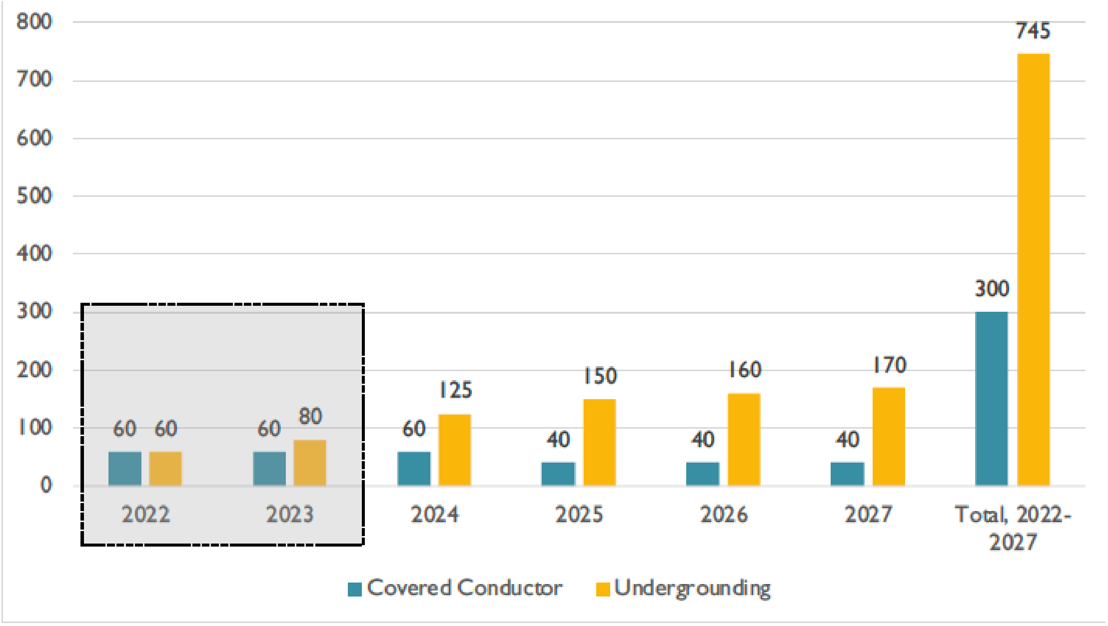
Mileage and Costs of Grid Hardening ($ thousands)

	Undergrounding				
	2025	2026	2027	2028	Total / Weighted Average
TURN Miles	44	44	44	44	177
SCE Miles	60	150	200	170	580
Unit Cost	*$ 5,083*	*$ 5,677*	*$ 5,717*	*$ 5,687*	*$ 5,632*
TURN Budget	$ 224,903	$ 251,227	$ 252,984	$ 251,633	$ 980,746
SCE Budget	$ 304,954	$ 851,620	$ 1,143,432	$ 966,727	$ 3,266,733
TURN-SCE	**$ (80,051)**	**$ (600,392)**	**$ (890,448)**	**$ (715,095)**	**$ (2,285,986)**

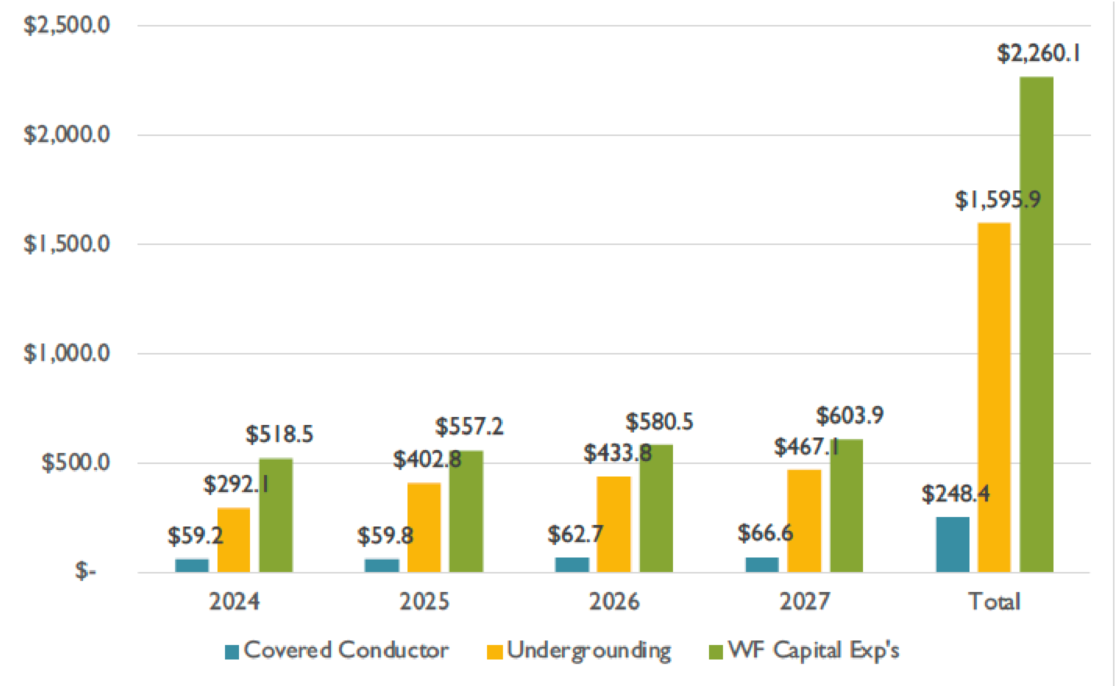
	Covered Conductor				
	2025	2026	2027	2028	Total / Weighted Average
TURN Miles	413	413	413	413	1,651
SCE Miles	850	300	50	50	1,250
Unit Cost	*$ 763*	*$ 778*	*$ 805*	*$ 812*	*$ 770*
TURN Budget	$ 314,921	$ 320,902	$ 332,373	$ 335,247	$ 1,303,442
SCE Budget	$ 648,666	$ 233,289	$ 40,271	$ 40,620	$ 962,845
TURN-SCE	**$ (333,745)**	**$ 87,613**	**$ 292,101**	**$ 294,627**	**$ 340,597**

Example: San Diego Gas and Electric (SDG&E) SDG&E Proposal

Covered Conductor vs. Undergrounding Miles



Covered conductor, Undergrounding, and Total Wildfire Expenditures ($2021, million)

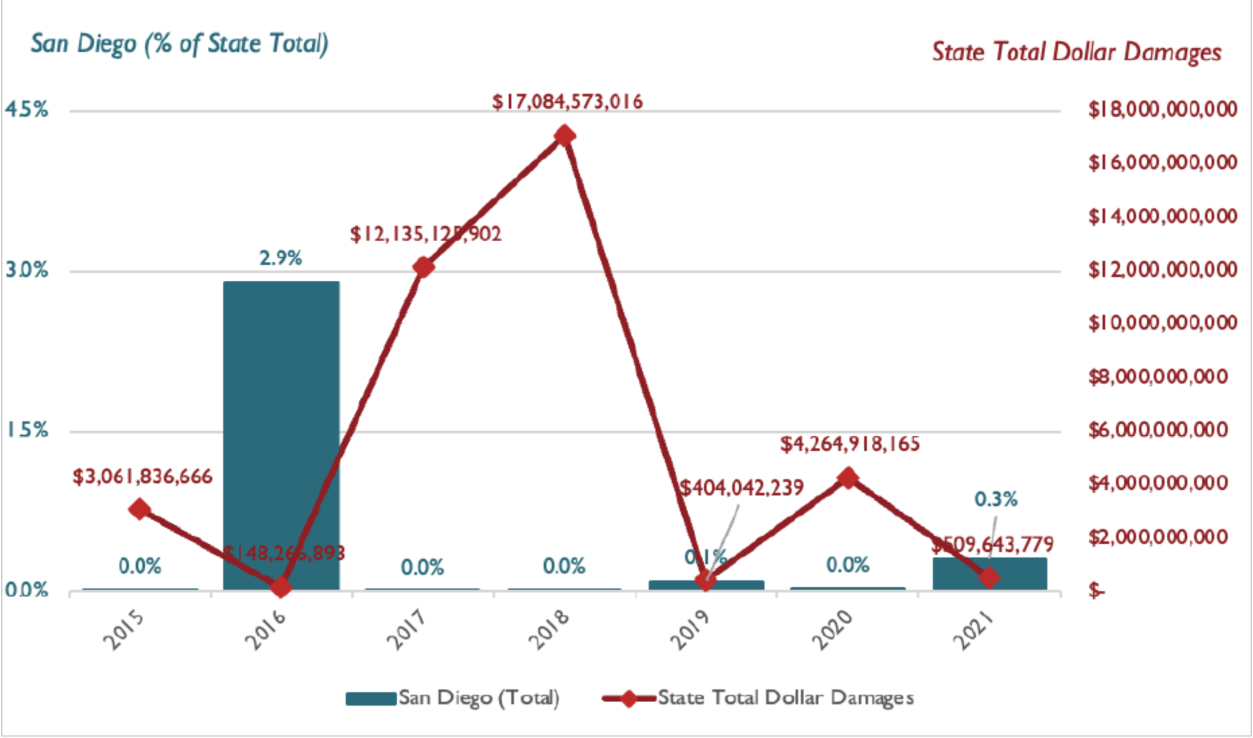


Example: San Diego Gas and Electric (SDG&E) Analysis – Risk Relative to Other California IOUs

Using San Diego County as a proxy, <u>unadjusted for utility-specific risk</u>, San Diego accounted for a maximum of 3.3% of acres burned in CA and 2.9% of damages from 2015-2021

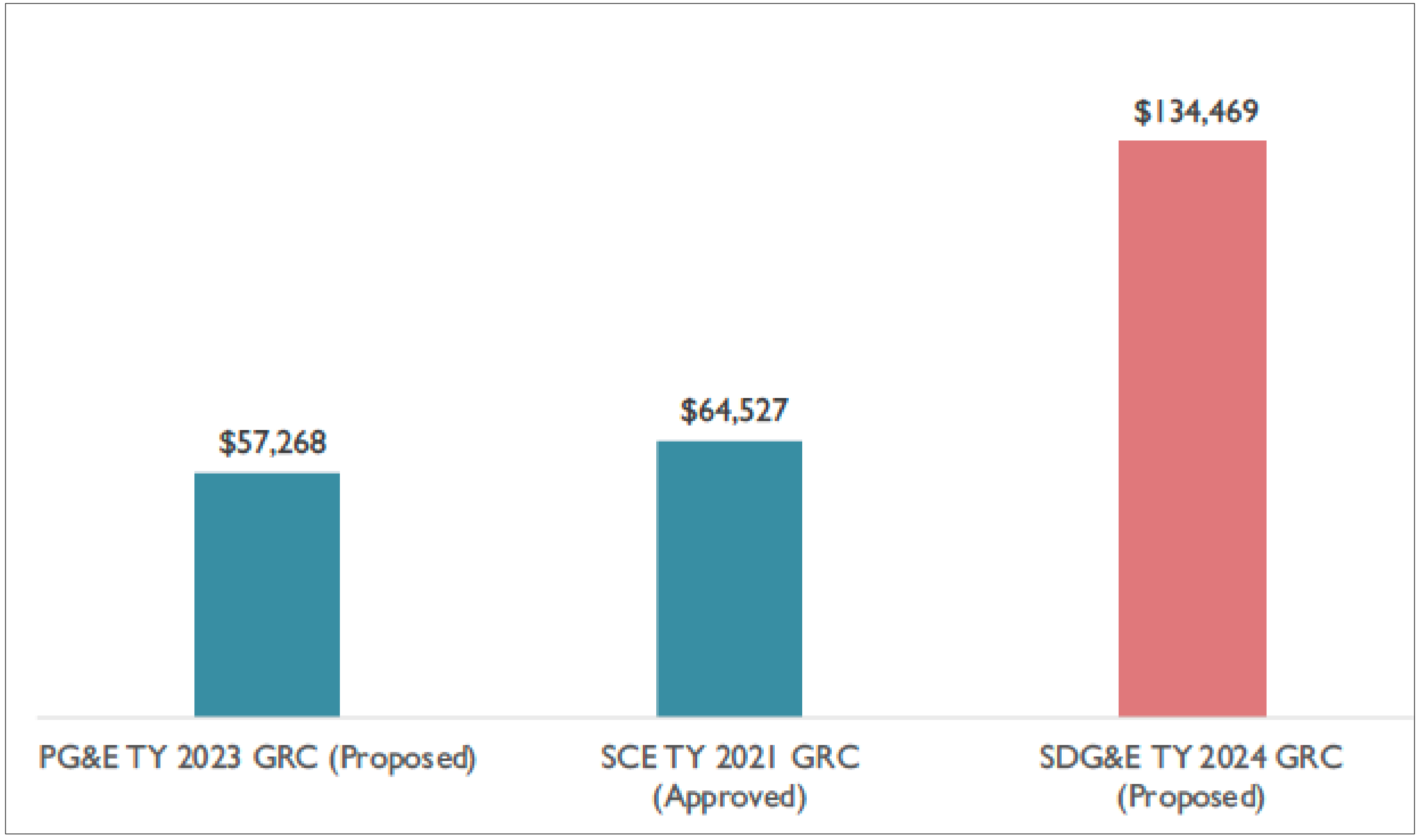
San Diego County, Percentage of Acres Burned 2015-2021

San Diego County, Percentage of Dollar Damages 2015-2021



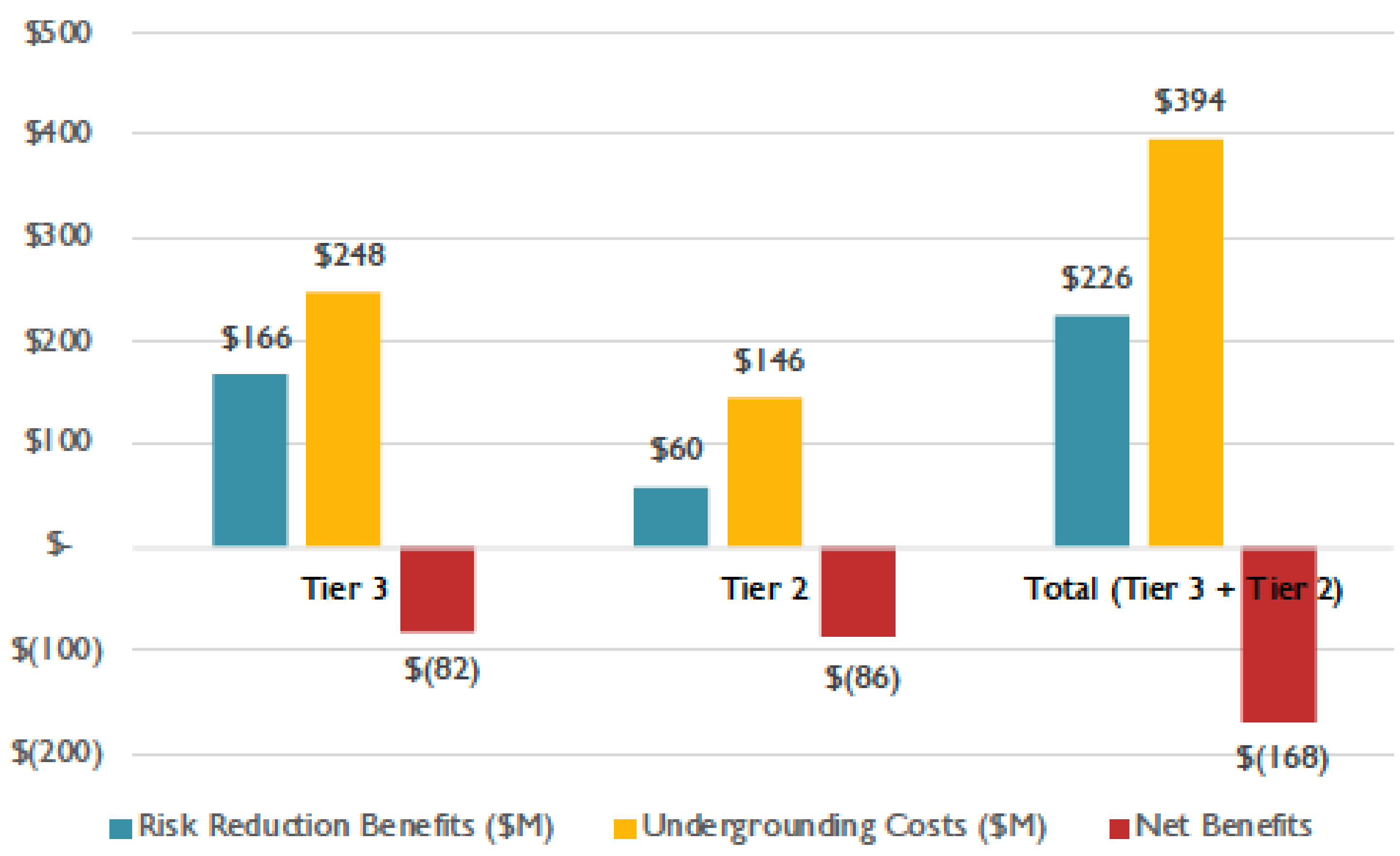
Example: San Diego Gas and Electric (SDG&E) Analysis – Risk Relative to Other California IOUs

Average Annual Undergrounding and Covered Conductor Cost per HFTD Overhead Mile ($2021)



Example: San Diego Gas and Electric (SDG&E) Analysis – Benefits vs. Costs of SDG&E Proposal

Undergrounding Risk Reduction versus Costs



Example: San Diego Gas and Electric (SDG&E) Synapse/TURN Proposal

- We proposed 465 less undergrounding miles and 260 more covered conductor miles than SDG&E.
- This achieves 78% of the risk reduction benefits for 35 percent of the costs.
- With Public Safety Power Shutoffs (PSPS), wildfire risk is reduced to near-zero, but this worsens reliability.
  - Undergrounding is by far the least cost-effective way to mitigate PSPS risk.
- Our proposal was adopted by the CPUC.

Incorporating Equity Considerations

- Equity starts with affordability due to the regressive nature of energy costs.
- Equity also considers disparate impacts on vulnerable populations.
  - The costs for undergrounding projects are socialized across all customers, but undergrounding for reliability inherently benefits a small subset of these customers.
  - For example, is we use Value of Lost Load (VOLL) as the basis for reliability benefits, predominately commercial and industrial customers may be targeted for these projects. Similarly, if wealthy households tend to use more energy, the analysis may indicate solutions that benefit these households while not adequately considering impacts on vulnerable populations.
    - This issue can be addressed directly in the BCA or qualitatively outside of the BCA.

Reliability example: weighting and "tranches" to help prioritize vulnerable populations

- Extreme: Public Safety Partners; Provides Emergency Services
- Significant: Life Support customers or Medical Baseline customers who are low income
- Elevated: All other Medical Baseline, all other critical customer designations
- Regular: Regular customer

Line No.	Tranche	Exposure (%)	Safety Risk Value ($M)	Reliability Risk Value ($M)	Financial Risk Value ($M)	Aggregated Risk Value ($M)	Risk (%)
1	Regular	77%	19.4	1,577.0	25.9	1,622.4	44%
2	Elevated	18%	12.2	990.0	16.3	1,018.5	28%
3	Significant	5%	9.1	736.9	12.1	758.1	21%
4	Extreme	0%	3.1	248.7	4.1	255.8	7%
5	Total	100%	43.8	3,552.6	58.3	3,654.7	100%

Source: PG&E 2024 RAMP filing, online: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/reports/2024-ramp-application-pge051524.pdf.

Questions?

Sources

- Federal Emergency Management Agency (FEMA), 2025. Data Resources. Available at Data Resources | National Risk Index.
- **California Public Utilities Commission (A.23-05-010):** Direct Testimony of Eric Borden addressing Southern California Edison's Test Year 2025 General Rate Case Wildfire Grid Hardening Investments. On behalf of the Utility Reform Network. February 29, 2024.
- **California Public Utilities Commission (A.22-05-016):** Prepared Testimony Addressing San Diego Gas and Electric's Test Year 2024 Wildfire Mitigation Hardening Measures and Related Wildfire Risk Modeling Issues for The Utility Reform Network. March 27, 2023.
- PG&E 2024 RAMP filing, online: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/reports/2024-ramp-application-pge051524.pdf.

Undergrounding Technical Conference| September 19, 2025

Michigan Public Service Commission

CITIZENS RESEARCH COUNCIL OF MICHIGAN

Potential to Improve Grid Resilience through Policy Solutions that Enable Undergrounding Power Lines

- Founded 1916
- Statewide, non-partisan, private not-for-profit
- Promotes sound policy for state and local governments through factual research – accurate, independent, and objective
- Relies on charitable donations from foundations, businesses, and individuals

Eric Paul Dennis, PE

- BSE, Civil Engineering, Michigan State University, 2006
- MSE, Environmental Engineering, University of Michigan, 2010
- MS, Urban and Regional Planning, University of Michigan, 2012
- Michigan-licensed PE since 2012
- Joined CRC in January 2022 as Research Associate of Infrastructure Policy

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QUALITY OF LIFE

Michigan power outages: Thousands could remain without service for days

by Janelle D. James
February 23, 2023

- *Winter storm dumps heavy ice in lower Michigan and at least 5 inches of snow in upper Michigan*
- *More than 700,000 people are without power,*
- *Power is expected to be restored for most by Sunday*

mLIVE Michigan

NEWS

'Catastrophic' damage: Thousands of miles of powerlines smothered in ice after Northern Michigan storm

Updated: Apr. 01, 2025, 1:59 p.m. | Published: Apr. 01, 2025, 1:22 p.m.

More than 40,000 GLE customers are without power today. Consumers Energy reports more than 90,000 without power; however, some of that is in southern Michigan where there was a devastating wind storm over the weekend.

"There is no such thing as a 'natural disaster.'"

2023 Public Comments:

Page

STATE OF MICHIGAN

MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of:

Town Hall to take public comment on
outages from recent winter storms.

/

PUBLIC HEARING

13800 Ford Road, Dearborn, Michigan

Monday, March 20, 2023, 5:30 p.m.

PANEL: DAN SCRIPPS
MPSC Commissioner

TREMAINE L. PHILLIPS
MPSC Commissioner

KATHERINE PERETICK
MPSC Commissioner

RECORDED BY: Anna Burns, CER 9214
Certified Electronic Recorder
Network Reporting Corporation
Firm Registration Number 8151
1-800-632-2720

- Outages up to 14 days
- Lost food
- Lost medicine (insulin)
- Lost wages
- Dark, cold homes
- No water for customers with wells
- Struggles with home care patients, children, pets
- Oxygen, heart monitors, CPAP machines, etc.
- Motels booked or closed
- Poor communication by utility
- Closed businesses
- Extended school closures
- Imposed hardship, crisis, struggle to survive
- Service loss stipend is insufficient, insulting

"They've torn up my street. They've taken out all the trees. … They're redoing the street, and yet they are not burying the power lines.

One of the complaints is that it's all the infrastructure they have to work around. It's all torn up! They replaced the water lines. They're replacing the sidewalk today.

Why in the heck are they not out there burying the power lines?"

~ Onsted (Lenawee Co.) resident and home care nurse

CITIZENS RESEARCH COUNCIL OF MICHIGAN

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GET INVOLVED

RESEARCH DETROIT BUREAU PODCAST BLOG EVENTS ABOUT CONTACT

MARCH 29, 2023

Undergrounding Electrical Lines is an Option to Prevent Power Outages, but State Policy is Needed to Better Enable the Practice

https://crcmich.org/dennis_digonce_underground_prevent_power_outages

- Stand-alone projects to underground lines cost 3-10 times as much as updating or 'hardening' projects.
- Additional costs would be passed on to ratepayers, or taxpayers if done at direction of government.
- No formal framework to underground utilities within 'dig-once' projects.
- Socioeconomic costs imposed by power outages are not typically considered in benefit:cost analyses guiding investments.
- MPSC regulatory authority is limited.

"My street is all torn up! They're redoing the street. They've taken out all the trees. They replaced the water lines. They're replacing the sidewalk today.

Why in the heck are they not out there burying the power lines?"

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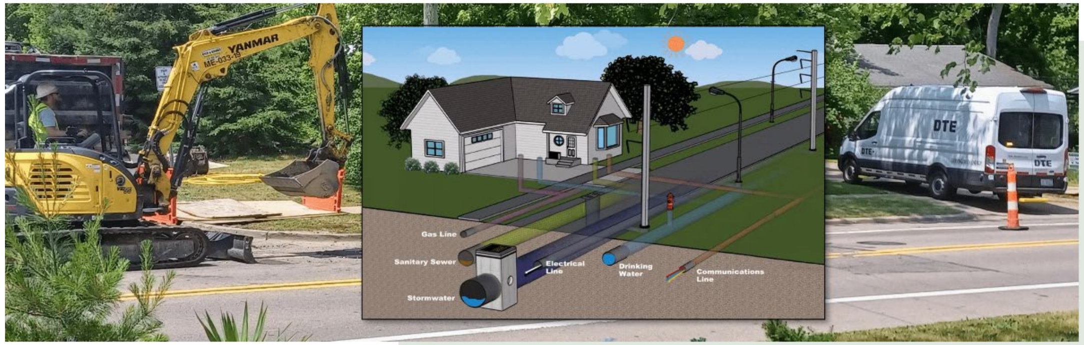
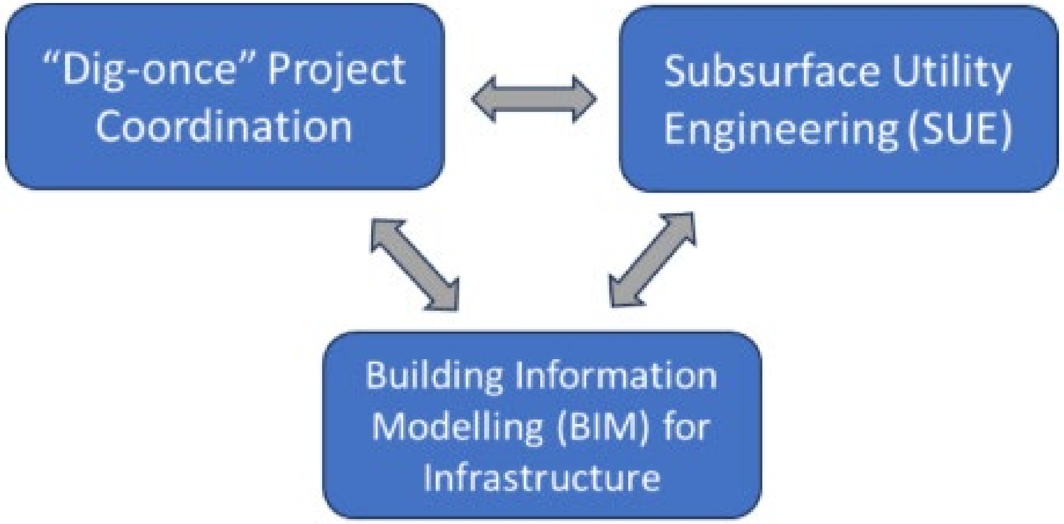


JUNE 21, 2023

Legislative Direction is Needed to Facilitate Infrastructure Coordination

- Infrastructure management in Michigan is largely uncoordinated between various infrastructure owners who must share common right-of-ways. This imposes cost inefficiencies for all agencies, which are passed-on to the public as taxpayers and utility ratepayers.
- The cost burden of all types of infrastructure could be reduced if the various agencies were to pool resources for multi-agency construction projects, share quality data on the location of their assets, and adopt a shared long-term vision for right-of-way management.
- Michigan should pursue statutory options that will enable and support infrastructure owners and operators to more efficiently coordinate towards common objectives in the public interest.

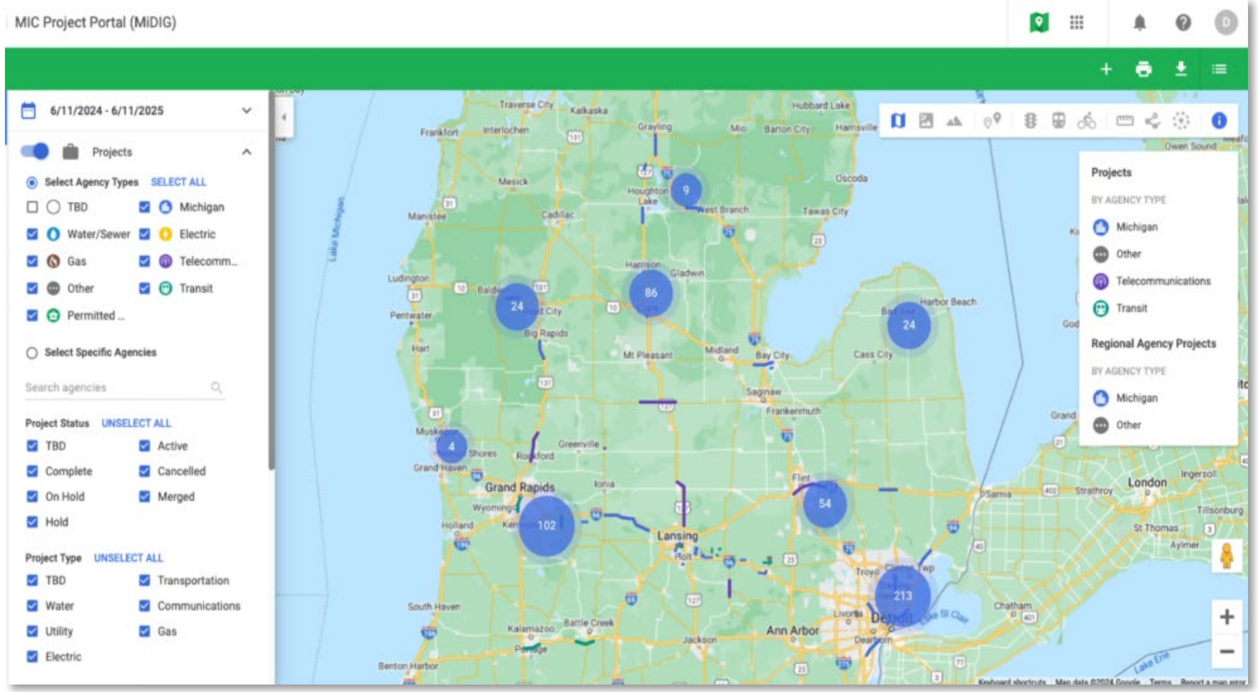


https://crcmich.org/legislative-direction-is-needed-to-facilitate-infrastructure-coordination

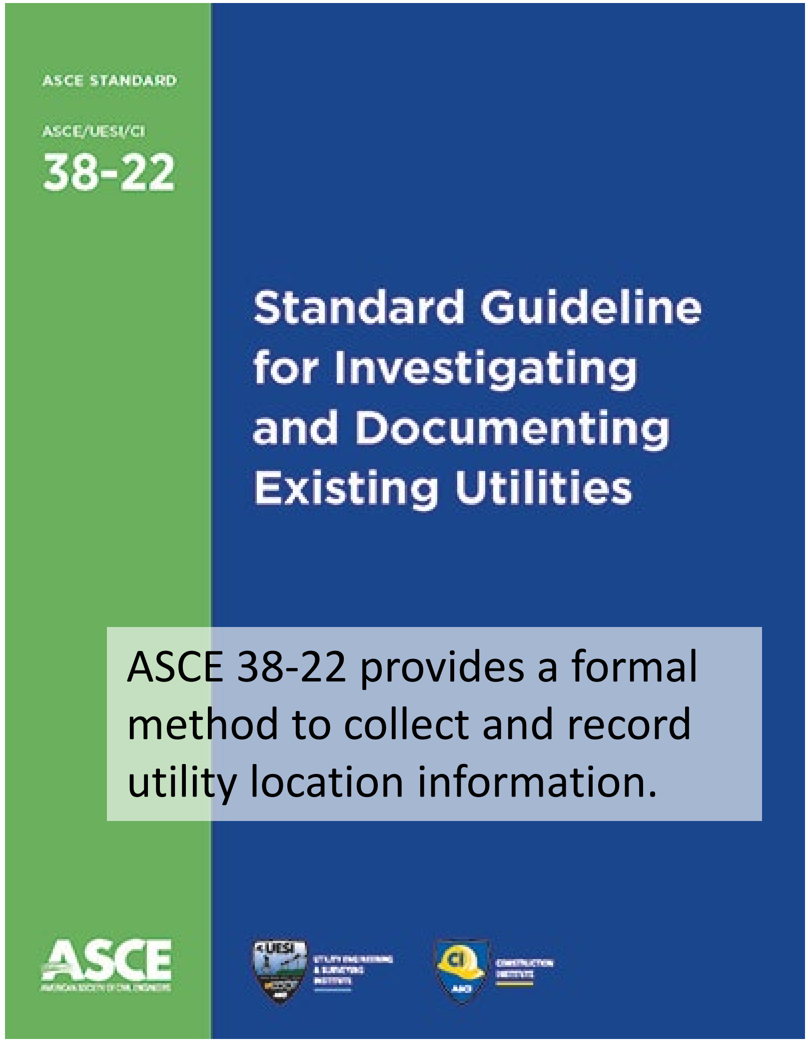
Dig-once Legislation (Near-term)

- Rationalize existing dig-once initiatives across the state to **avoid duplicative efforts** and encourage participation. … ✓(?)
- **Establish a regulatory role for state-level infrastructure coordination** and management of the dig-once platform. Provide the infrastructure coordinator with sufficient resources and authority to identify dig-once projects that are not proposed through voluntary efforts, adjudicate disagreements between ROW users, and allocate funding as appropriate.
- Provide **dedicated dig-once project funding** to public agencies and utilities to enable compliance with participation requirements. (The benefits of dig-once coordination will accrue to the general public, Thus the costs of coordination should not be borne solely by project budgets.)
- Provide the infrastructure coordinator with **enforcement mechanisms** to ensure earnest participation in the program from all required entities.
- Recognize that while short-term benefits are achievable through a dedicated dig-once platform, the long-term vision should better enable life-cycle management of all infrastructure. **Task State Infrastructure Coordinator with evolving the platform**.

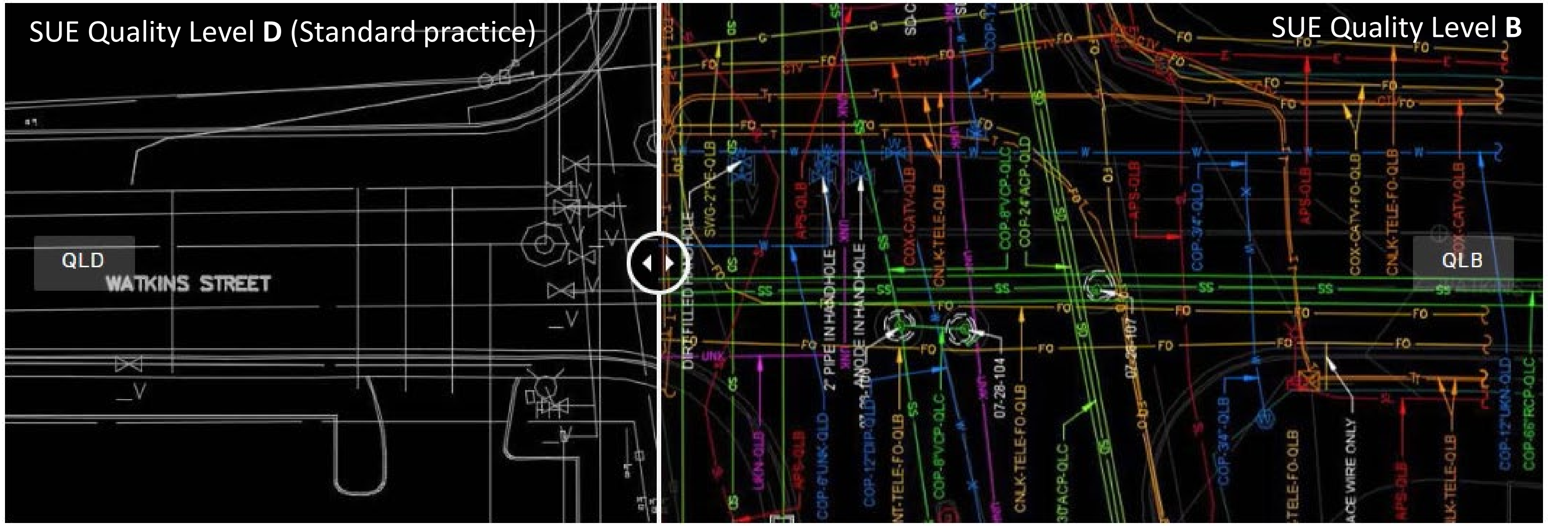
Michigan Infrastructure Council



Subsurface Utility Engineering (SUE)



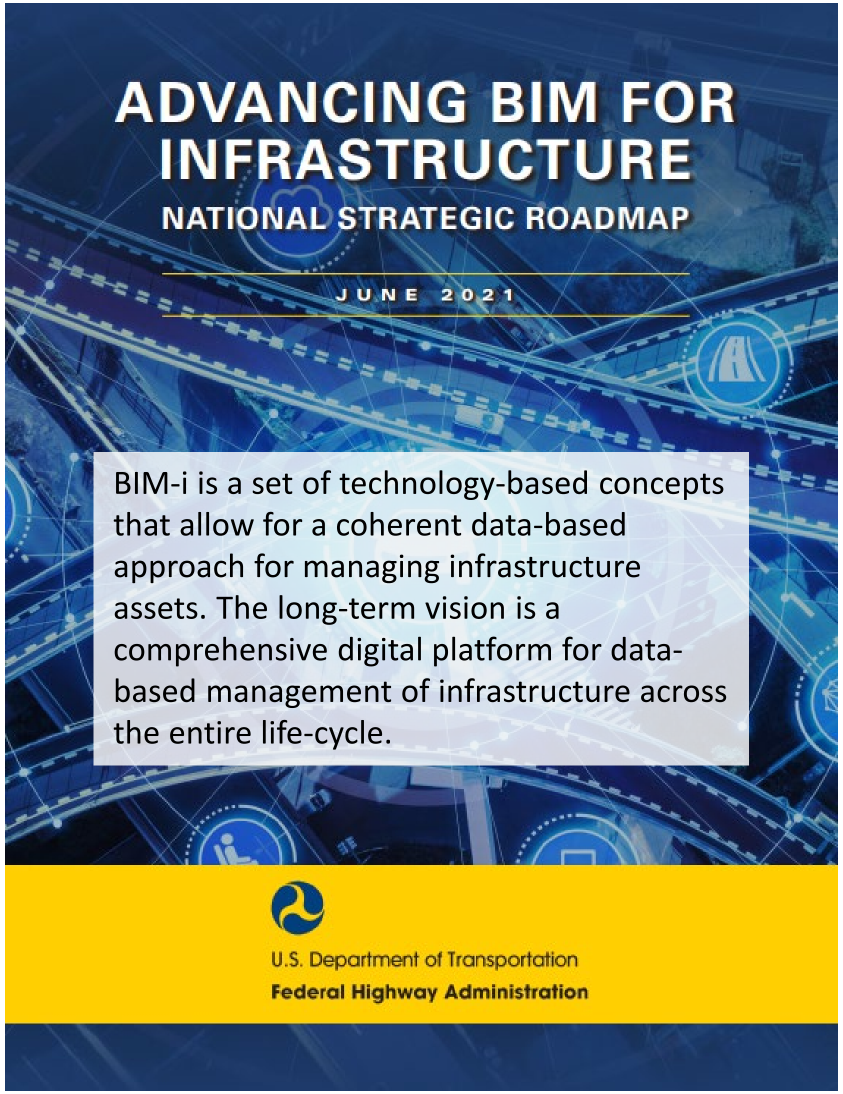
ASCE 38-22 provides a formal method to collect and record utility location information.



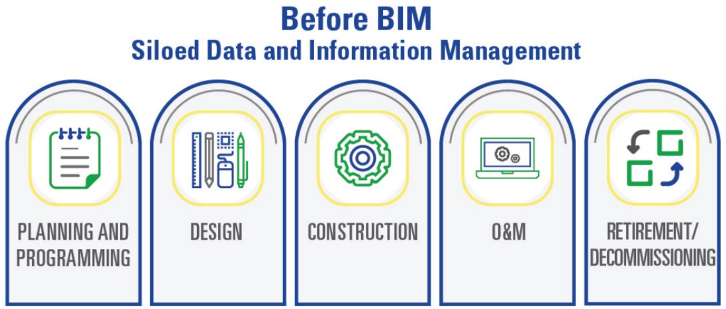
SUE Legislation (Medium-term)

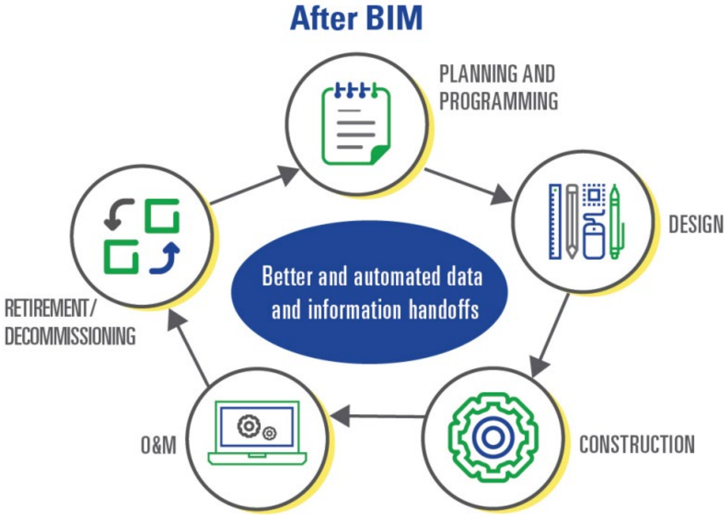
- **Require the use** of ASCE 38-22-complaint SUE for all public projects that meet certain requirements (e.g., a project cost threshold).
- **Establish a statewide platform** for SUE document sharing.
- **Provide a funding mechanism** to subsidize SUE efforts, along with regulatory authority to distribute funds and ensure compliance of deliverables.

Building Information Modelling for Infrastructure (BIM-i)



BIM-i is a set of technology-based concepts that allow for a coherent data-based approach for managing infrastructure assets. The long-term vision is a comprehensive digital platform for data-based management of infrastructure across the entire life-cycle.





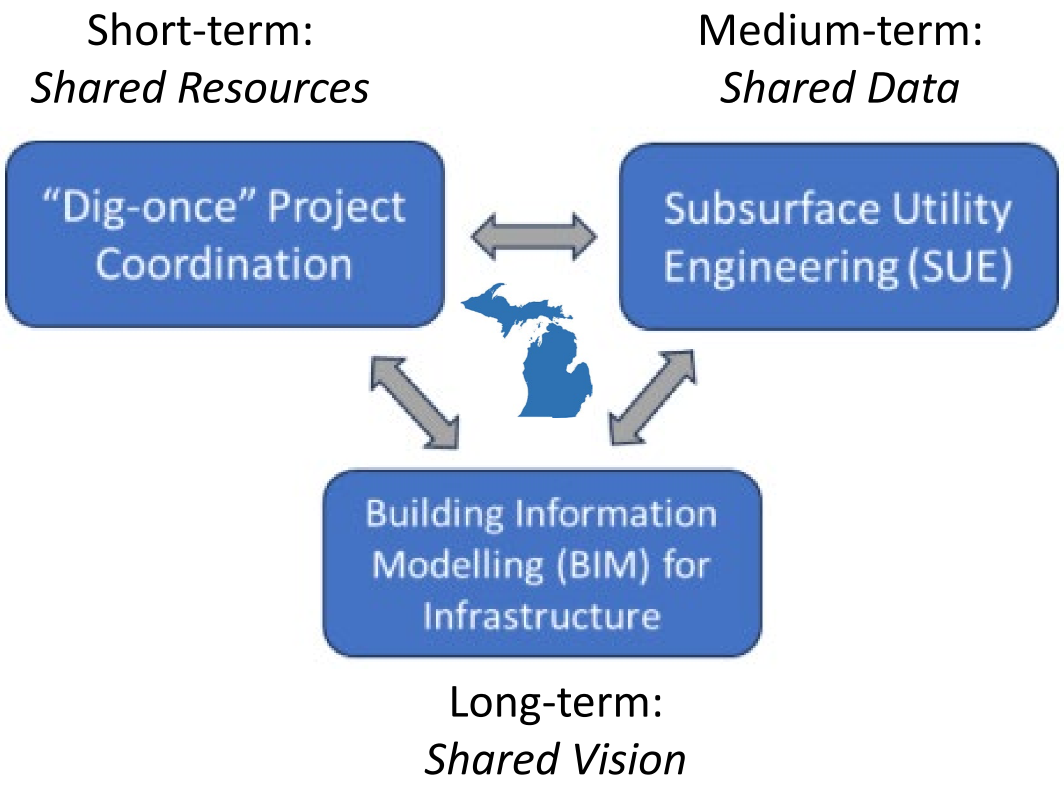
O&M: Operations and Maintenance, which includes Asset Management

BIM-i Legislation (Long-term)

Initial legislative efforts must be unobtrusive and deliberate. Specifically, the legislature should establish a statement of principles that Michigan wishes to pursue a statewide BIM for infrastructure strategy and create a commission or working group to study the issue and report back with recommendations. Ideally this would be coordinated through a new State Office of Infrastructure Coordination.

Long-term goal is to establish a shared vision for infrastructure design and life-cycle management within the public right-of-way.

https://crcmich.org/legislative-direction-is-needed-to-facilitate-infrastructure-coordination



Possibilities for Progress without Legislation

MPSC has some limited ability to encourage undergrounding when it makes sense.

- Review Benefit:Cost Analyses
    - Consider benefits of risk mitigation of catastrophic outages, including socioeconomic factors
    - Update underground/overhead reliability data, life-cycle costs
    - Update climate assumptions, including tree growth rates due to longer growing season and establishment of rapidly-growing invasive species
    - Reconsider “aesthetic benefits” (2007 report)
- “Nudge” utilities to cooperate with local governments with dig-once projects.
    - Share data on depreciated costs of existing facilities, expected service life, circuit priority
    - Revise Mich Admin Code Rule 460 to allow for undergrounding during replacement of circuits
    - Establish undergrounding fund for cost-sharing (?)

“The Commission should consider amending [Rule 460.517] so that it allows burying…where overhead distribution and service lines are due for replacement. We are very rational actors in Farmington. We just want the opportunity to understand the cost-benefit of burial when the time comes.”

~ *Joe LaRussa, Mayor of Farmington*

“My street is all torn up! They’re redoing the street. They’ve taken out all the trees. They replaced the water lines. They’re replacing the sidewalk today.

Why in the heck are they not out there burying the power lines?”

If you find value this work, please consider a tax-deductible donation:
CRCmich.org

CITIZENS RESEARCH COUNCIL OF MICHIGAN

Eric Paul Dennis, PE
epdennis@crcmich.org

System Modernization & Reliability Project

Steven Herbel – Wisconsin Public Service

Agenda

- Background on the Project
  - The Problem
  - The Goals
- Execution of the Project
  - Strategy
  - Problems
  - Solutions
- Completion of the Project
  - Reliability Results
  - Lessons Learned

Background for SMRP

Background for SMRP

- Wisconsin Public Service (WPS)
  - 453,000 electric customers
  - 18 Wisconsin Counties (11,000 sq miles)
- The Problem
  - 71% of the service area is medium to high-density forest
  - Need for reliability improvement when compared to industry benchmarks and other Midwest utilities
  - Challenge to maintain vegetation clearances and deal with hazard trees
  - Aging overhead lines

Background for SMRP

- Additional Background
  - Project began in 2014
  - Almost half of customers surveyed indicated they valued and were willing to pay for improvements through increased electric rates
  - Advancements in underground cable installation and testing techniques

Background for SMRP

- The Goals
  - Install 1000 miles of underground to replace overhead lines
    - Additional 1000 miles was added as Phase 2 of project
  - Deploy distribution automation (DA) equipment on 400 miles of existing three-phase mainline
  - Improve reliability (reduced SAIDI)
    - “Improved performance at a reasonable cost”
  - Reduce O&M expenses

Distribution Automation

Execution of the Project

- Project work started two years before construction
- Extensive coordination with:
  - U.S. Army Corps of Engineers
  - State Historic Preservation Office
  - Wisconsin Department of Natural Resources
  - U.S. Fish and Wildlife Service
  - U.S. Forest Service

Execution of the Project

- Environmental inspectors were employed and dedicated to the project
  - Meet with crews, monitor, and inspect
- Techniques included plowing, boring and open cutting
- Used partial-discharge testing techniques to verify the quality of materials and workmanship
  - Terminations and splices identified as high risk areas
- Contacted over 50,000 landowners

Execution of the Project

- Issues
  - High impact mainlines are expensive to rebuild underground
  - High voltage concerns on distribution system due to the amount of underground cable installed
  - Easement refusals or unable to contact with landowners

Execution of the Project

- Solutions
  - Distribution Automation was an alternative to burying 3 phase mainline overhead lines
  - Inductors were installed as needed as part of the project
  - Mail hard copies to customers well in advance and follow up with duplicate mailings
  - Willing to cancel a project if significant issues with customer cooperation
    - Sometimes walking away from a project got cooperation in a future year

Completion of the Project

- Reliability Data
  - SMRP project area contribution to total system SAIDI
  - SAIDI numbers are calculated on a utility-wide basis, inclusive of the entire WPS customer base

	Year of Installation					
	2014	2015	2016	2017	2018	2019
Pre-SMRP average SAIDI (minutes)	22.84	21.09	21.67	22.83	18.61	23.02
Post-SMRP average annual SAIDI (minutes)	0.49	0.36	0.43	0.59	0.46	0.12
Improvement (minutes)	22.35	20.72	21.24	22.24	18.15	22.90
Improvement (%)	98%	98%	98%	97%	97%	99%

Completion of the Project

- Lessons Learned
  - "Improved performance at a reasonable cost" left behind some big reliability concerns
  - Distribution Automation does not prevent any outages, only reduces the impact at times
  - Project selection left behind some overhead in what is now mostly underground areas

GridCo Partners

Resilience Metrics & Valuation for Electric Grid Decision-Making

Presented by | Shikhar Pandey

September 19, 2025

Outline

- Need For Resilience
- IEEE Resilience Metrics
- System Resilience
- Operational Resilience
- Case Studies
- PNNL–GridCo: Valuing Resiliency

Need for Resilience

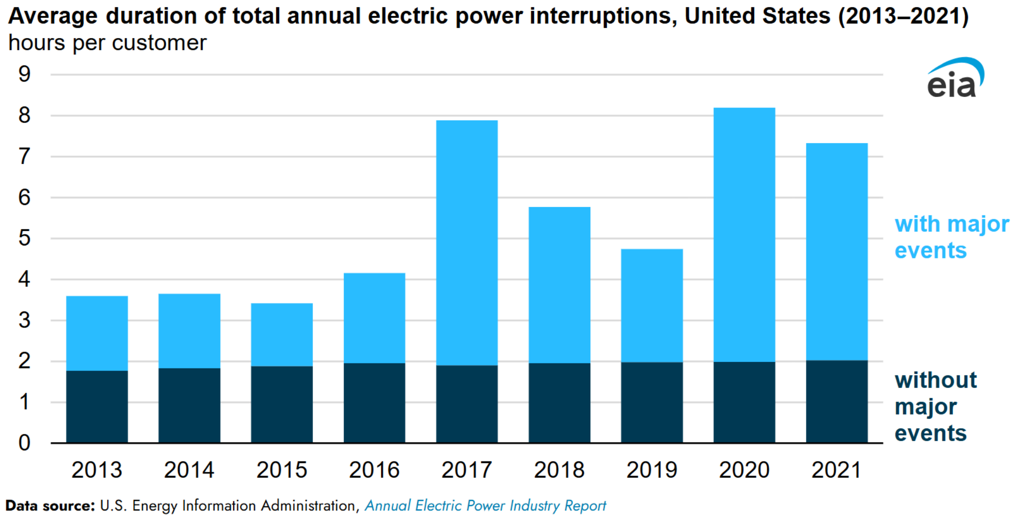
Increasing Weather Events and Damage

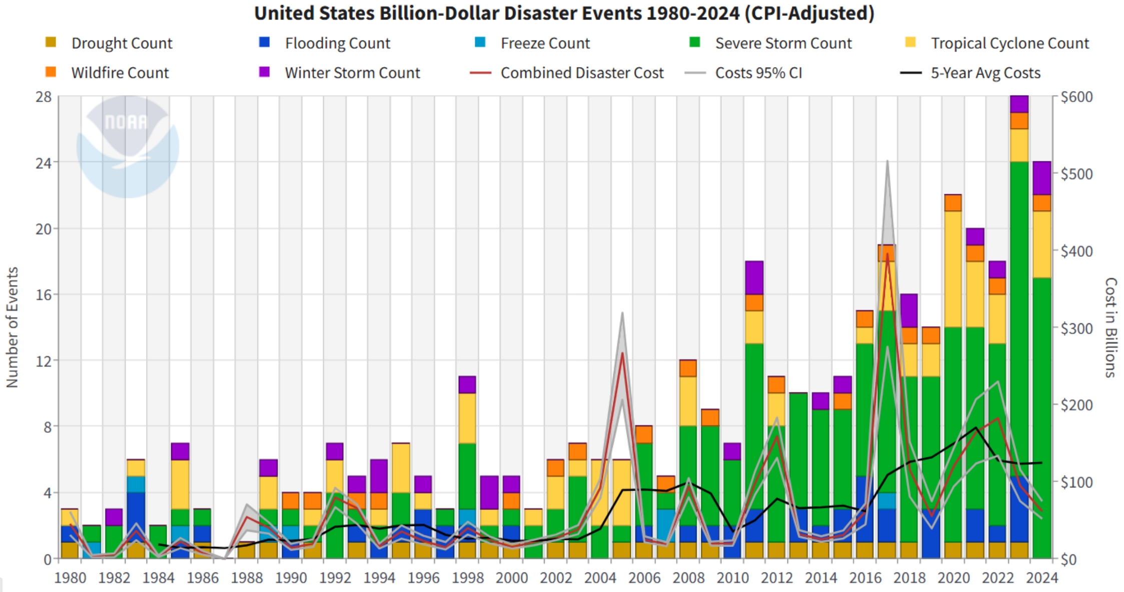
"Power outages from severe weather have roughly <u>doubled</u> over the past two decades." [1]

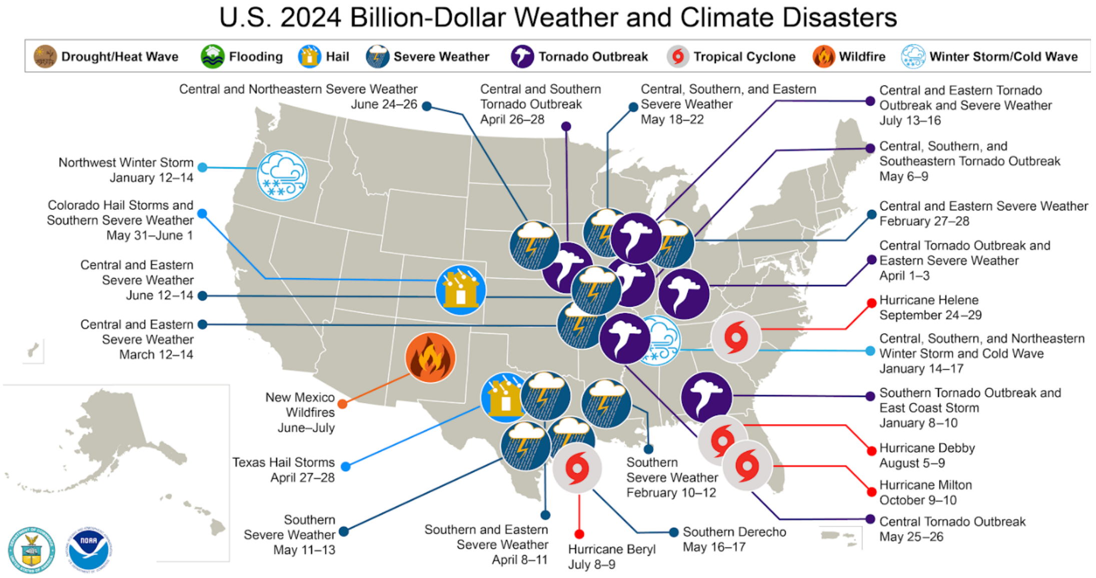
"Of all major U.S. power outages reported from 2000 to 2023, <u>83%</u> were due to weather." [2]

"The average home or business will go without power for 7 to 8 hours per year." [3]

"The 5-year average cost of major climate events increased <u>400%</u> over two decades" [4]







This map denotes the approximate location for each of the **24 separate billion-dollar weather and climate disasters that impacted the United States through October 2024.**

[1] <u>U.S. Is Facing More Power Outages Due To Extreme Weather | TIME</u> [2] <u>Surging Weather-related Power Outages | Climate Central</u>
[3] <u>U.S. electricity customers averaged seven hours of power interruptions in 2021 (EIA)</u>
[4] <u>Billion-Dollar Weather and Climate Disasters | National Centers for Environmental Information (NCEI)</u>

Storm Events – Increasing Expectations

Increased focus on Storm Events – No longer an Infrequent Outlier

Customer Expectations
- Resilient System
- Estimated Time of Restoration
- Affordability

Regulatory Requirements
- Stringent Metrics
- Performance Based Rate Making
- Storm Reporting

Industry Expectations
- Reliability Metrics
- **'New' Resiliency Metrics**
- **Distribution Resiliency Guide**

Inadequate for major events

IEEE Resiliency Metric

What is Resiliency

What is Resiliency?

FERC has proposed that resilience means the ***"ability to withstand and reduce the magnitude and/or duration of disruptive events,*** which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event."

Credit: Utility Dive Feb 2, 2018, by Kate Konschnik and Brian Murray

Proposed IEEE Definition

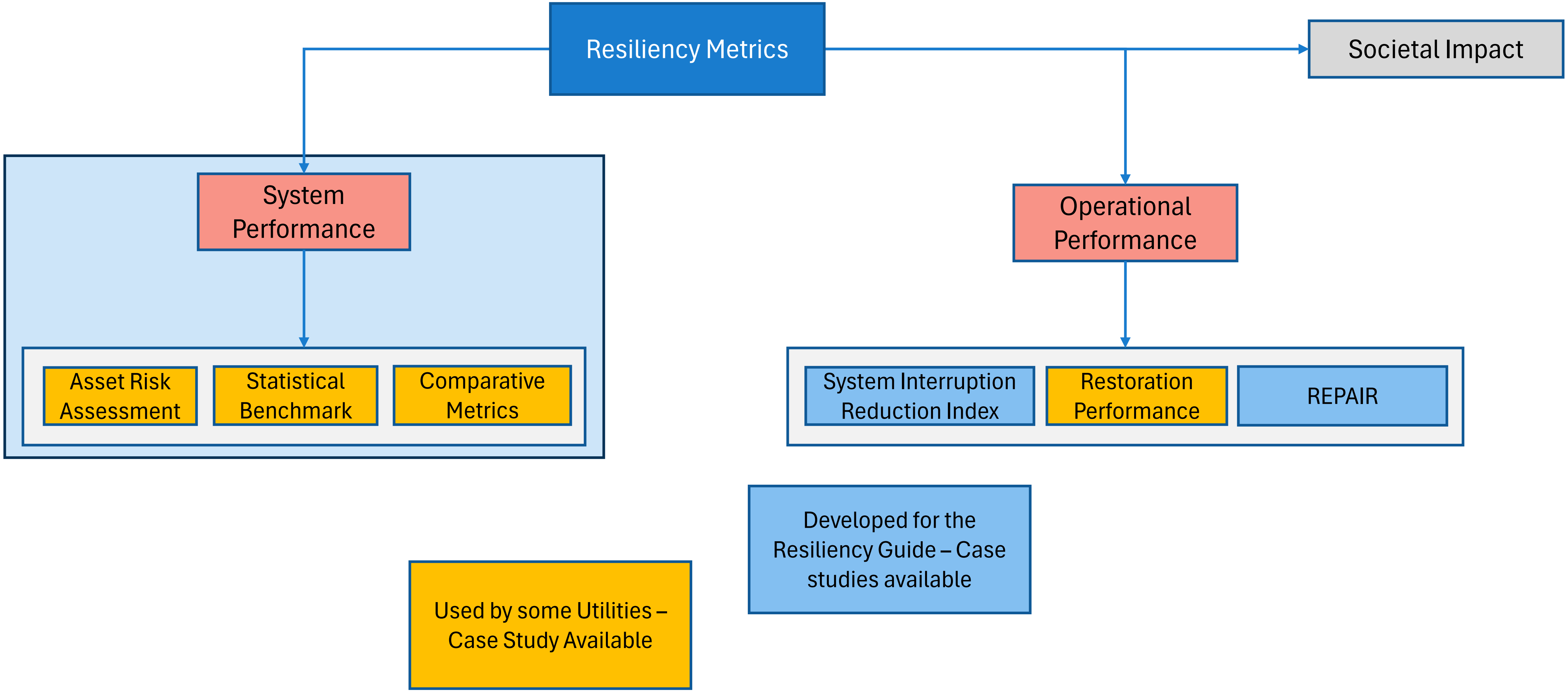
*The capability of electric power **distribution** systems to **deliver** electric energy to end-use customers by **avoiding interruptions and/or recovering this capability** following exposure to **naturally occurring high impact low frequency events.***

IEEE Distribution Resiliency Focus

Out of scope: BES, Cyber/Physical Security, Operational Events

Primary Focus: Extreme Weather Events, Natural Phenomenon

A Comprehensive Suite of Metrics



These metrics are designed by the IEEE Distribution Resiliency Taskforce. They are currently in draft and will be refined.

Assets Risk Assessment

1. **Climate Vulnerability Studies**: Utilities are assessing risks from climate hazards to understand the impact on their assets

Description	Temperature, Heat and Humidity	Flooding	Wind and Ice	Wildfire
Exposed Assets-At-Risk Properties	Thermal rating reduction, Accelerated asset degradation	Water-related equipment sensitivity, Corrosion, Soil Weakening	Wind and Ice Loading Tolerance, Vegetation Proximity	Fire-related equipment damage, Smoke on conductors, Soot accumulation over insulators, damaged insulators exhibiting high leakage currents, Vegetation Proximity

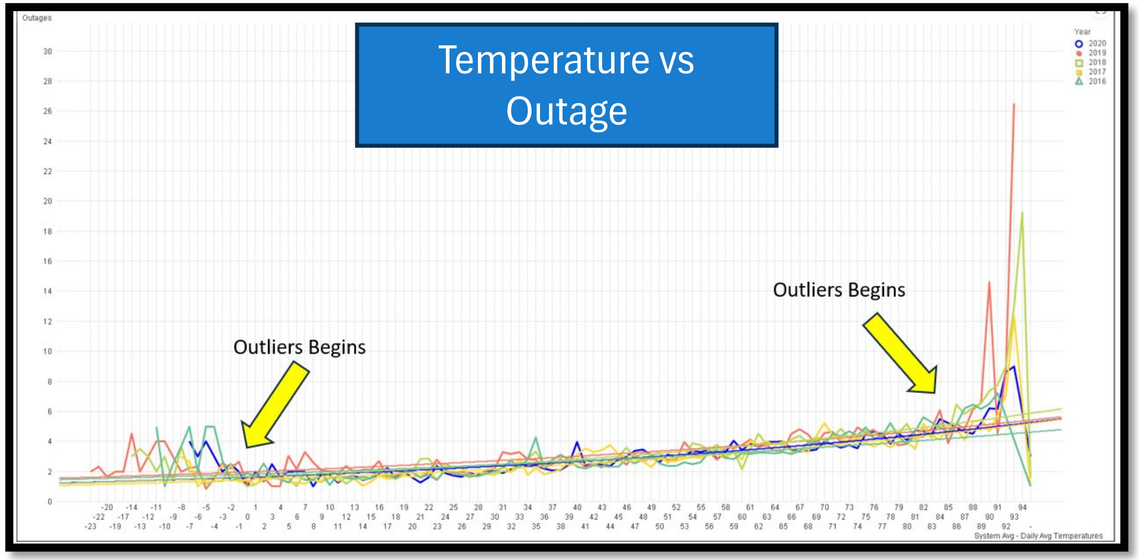
2. **Asset-Risk Assessment Metric**: Utilizes two matrices:
   - **Exposure Properties to Risk Matrix**: Identifies asset properties affected by climate change
   - **Assets-to-Exposure Matrix**: Prioritizes asset strengthening based on risk levels (medium, high, low) against climate change variables

Equipment vs Threat	Temperature, Heat and Humidity	Flooding	Wind and Ice	Wildfire
Substation	High Risk	High Risk	Low Risk	Low Risk
Overhead Equipment	Medium Risk	Low Risk	High Risk	High Risk
Underground Equipment	High Risk	Medium Risk	Low Risk	Low Risk

Statistical Benchmark: Outages on Gray Sky days

Gray Sky Day: Focuses on robustness and the ability to withstand most weather events

- We established a statistical benchmark based on weather parameters and historical outages
- This benchmark tracks the system performance (of outages) during gray sky days



Yellow

- **Average temperature** between 80 and 85 degrees
- **Average temperature** between 0 and -5 degrees
- **Average sustained wind speed** between 25 and 30 MPH
- **Average of one-hour wind gust** between 25 MPH and 30 MPH
- **Average rainfall** between 0.75" and 1"
- **Lightning stroke count** between 3,000 and 6,000

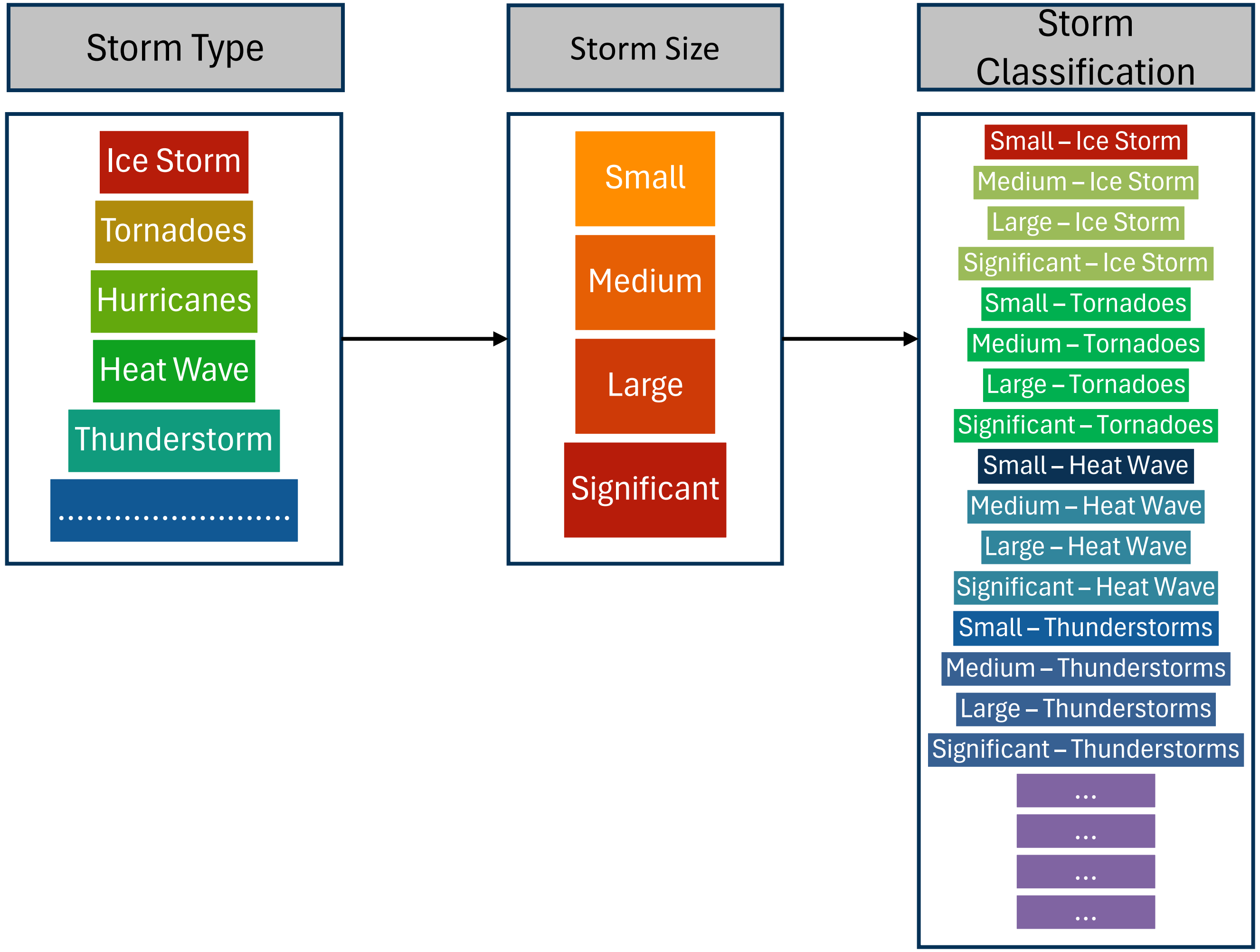
Orange

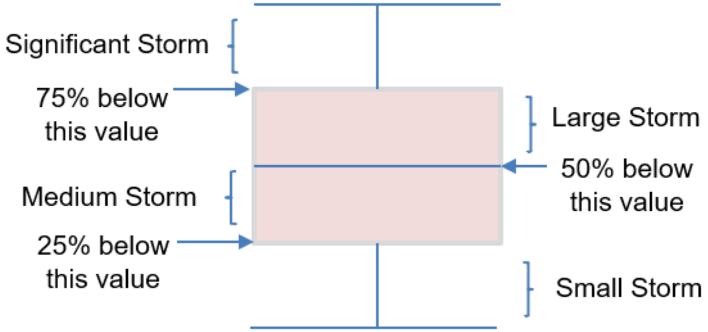
- **Average temperature** between 85 and 90 degrees
- **Average temperature** between -5 and -10 degrees
- **Average sustained wind speed** between 30 and 35 MPH
- **Average of one-hour wind gust** between 30 MPH and 35 MPH
- **Average rainfall** between 1" and 1.25"
- **Lightning stroke count** between 6,000 and 10,000

Red

- **Average temperature** greater than 90 degrees
- **Average temperature** less than -10 degrees
- **Average sustained wind speed** >= 35 MPH
- **Average of one-hour wind gust** >= 30 MPH
- **Average rainfall** greater than 1.25"
- **Lightning stroke count** greater than 10,000

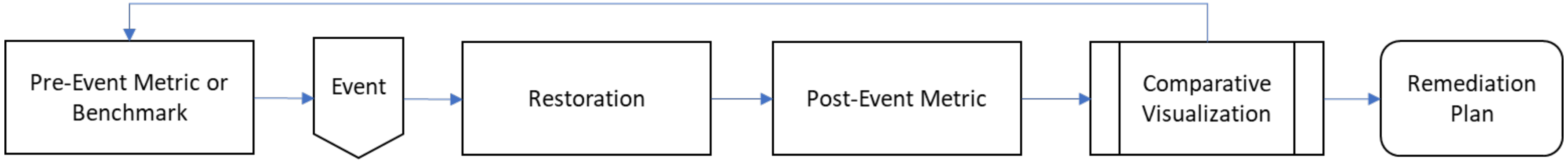
Storm Classification





It is Important to classify different storm categories to apply the metrics on.

Comparative Metrics



Metric	Attributes	Historical Benchmark	Current Event Records	Performance Assessment
Storm Strength Comparison	Wind Speed	70 mph	80 mph	Increased wind speed, correlates with longer outages
	Precipitation	2 inches	3 inches	Higher precipitation, potential cause for disruptions
Flood Comparison – Substations/Underground Equipment	Substation Outages due to Flood	5 incidents	3 incidents	Improved resilience, fewer outages
	Underground Equipment Outages due to Flood	10 incidents	12 incidents	Slight increase, review flood mitigation strategies
Square Miles Impacted/Customer Density	Square Miles Impacted	50 sq miles	60 sq miles	Larger area impacted, reassess preparedness
	Customer Density	1,000 customers/sq mile	1,200 customers/sq mile	Higher density, more significant impact
Pole Damage Comparison	Pole Damage Incidents	15 incidents	20 incidents	Increased incidents, consider reinforcement strategies
Equipment Damage Comparisons	Equipment Damage Incidents	30 incidents	52 incidents	Increased incidents, proactive maintenance strategy
Construction Person Hours to Restore Hardened vs. Non-Hardened	Construction Person Hours - Hardened	500 hours	450 hours	Improved efficiency, hardening measures effective
	Construction Person Hours - Non-Hardened	1,200 hours	1,400 hours	Increased time, need for further hardening measures
Smart Grid Performance	Smart Grid - Interruptions Avoided	300 incidents	350 incidents	Improvement, smart grid enhancing resilience
Equipment Comparison (Substation /Distribution)	Hardened Substation (Outages)	80,000	60,000	Improved performance, effective hardening measures
	Non-Hardened Substation (Outages)	86,667	125,333	Increased, monitor for further hardening
	Hardened Distribution (Outages)	106,667	155,333	Big increase, analysis needed
	Non-Hardened Distribution (Outages)	126,667	185,333	Increased vulnerability, consider reinforcement
Restoration Comparison to Prior Events	Restoration - 24 hrs	60% restored	55% restored	Slight delay, assess resource allocation
	Restoration - 48 hrs	85% restored	80% restored	Similar delay, possible need for more resources
	Restoration - 72 hrs	95% restored	92% restored	Minor delay, review efficiency
	Total Restoration Days	5 days	5.5 days	Slight increase, investigate specific challenges

Example on Comparative Metrics Application

$$\text{X-Parameter Performance Ratio (X-PR)} = \frac{\text{Incidents Avoided}}{\text{Incidents Avoided} + \text{Sustained Incidents}}$$

- Take a circuit that has 200 poles and historically experiences 20% of them being damaged during significant storms.

$$\text{Historical Pole Damage metric} = \frac{(200 - 40)}{(200 - 40) + (40)} \quad \mathbf{= 0.8}$$

- Event 1 affects 25% of the poles Event 2 affects 5% of the poles.

$$\text{Event 1 Pole Damage Metric} = \frac{(200 - 50)}{(200 - 50) + (50)} \quad \mathbf{= 0.75}$$

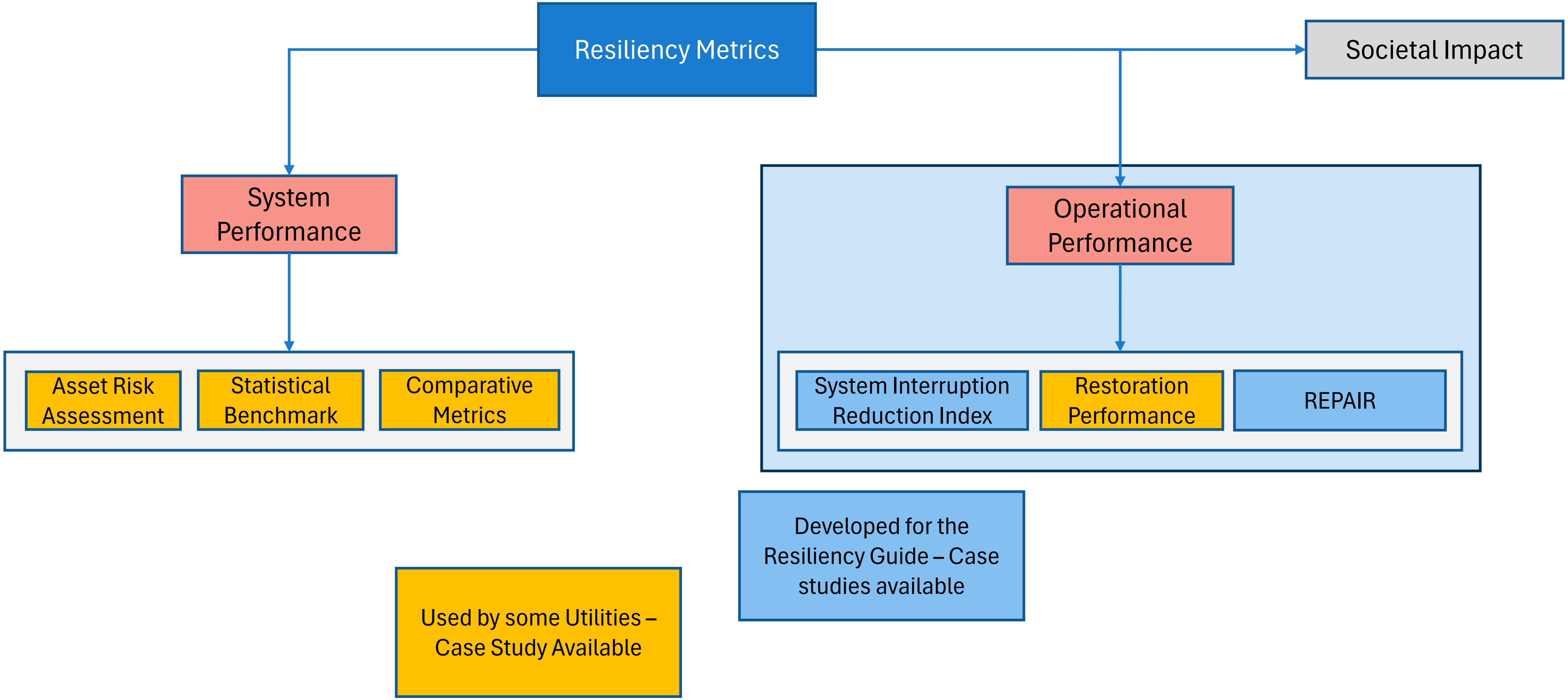
$$\text{Event 1 Pole Damage Ratio} = \frac{(0.75)}{(0.8)} \quad \mathbf{= 0.94}$$

$$\text{Event 2 Pole Damage Metric} = \frac{(200 - 10)}{(200 - 10) + (10)} \quad \mathbf{= 0.95}$$

$$\text{Event 2 Pole Damage Ratio} = \frac{(0.95)}{(0.8)} \quad \mathbf{= 1.19}$$

Ratio less than unity indicates system performance less favorable than historical; whereas the event ratio greater than unity indicates performance favorable than historical benchmark.

A Comprehensive Suite of Metrics



These metrics are designed by the IEEE Distribution Resiliency Taskforce. They are currently in draft and will be refined.

Sustained Interruption Reduction Index (SIRI)

$$\text{SIRI} = \frac{\text{Avoided Sustained Customer Interruption (CI) by Automation/Hardening}}{\text{Avoided Sustained CI by Automation/Hardening + Sustained CI}}$$

Aspect	Key Points
Perfect Resilience Scenario	Automation Performance **Ratio of 1** signifies perfect resilience, ensuring uninterrupted service and high customer satisfaction.
Factors Influencing the Ratio	**Automation Mechanisms:** Impact on outage prevention. **Sustained Outages**: Causes like equipment failure or external disruptions.
Real-World Implications	**Case Studies**: Successful automation in outage prevention. **Challenges**: Areas where automation needs improvement.
Trends Over Time	**Historical Analysis**: Trends in Automation Performance Ratio and automation strategies. **Continuous Improvement**: Informing ongoing efforts.
Comparisons with Other Metrics	**Comprehensive Resilience**: Alignment with other metrics. **Interconnected Nature**: Holistic understanding of grid resilience.
Operational Considerations	**Response Times**: Speed of detection, decision-making, and execution. **Adaptability**: Handling different disturbances.
Scalability and Adaptability	**Scalability Challenges**: For larger grid systems. **Technological Advances**: Enhancing automation systems.
Practical Applications	**Decision-Making Support**: Helps in prioritizing investments. **Customer Impact**: Improved service reliability through outage prevention.

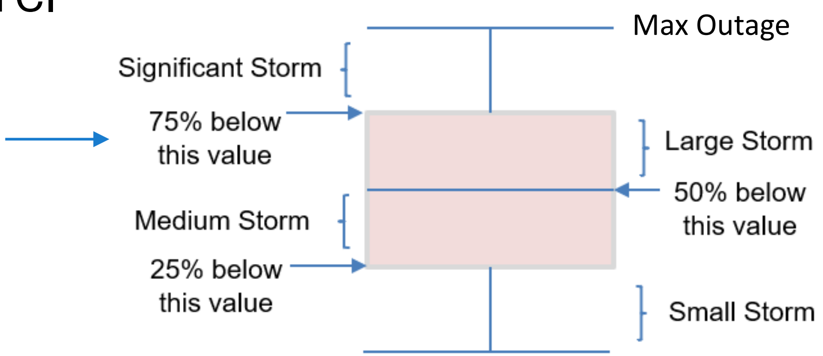
Restoration Performance

Calculation:

1) For each storm in a calendar year, calculate the ratio of customers without power for more than 12 hours and total customer interruptions (CI) including customers automatically restored (ACI) through smart switch operations (DA devices), community energy storage, and microgrids (does not include substation reclosing events – measured in %)

$$\text{Storm Event: } X = \frac{\sum \text{Customers Without Power for More than Z hours}}{\text{Avoided Sustained CI by Automation /Hardening + Sustained CI}}$$

2) Based on number of interruptions (storm outages), categorize each storm event significant, large, medium, or small



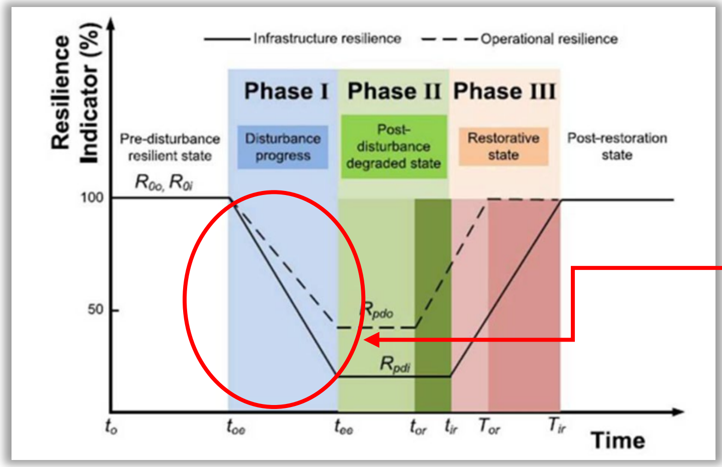
3) Determine if X is greater than or equal to the threshold value (Y) for the category

4) X<Y, storm met expectations. If X>=Y, storm did not meet expectations

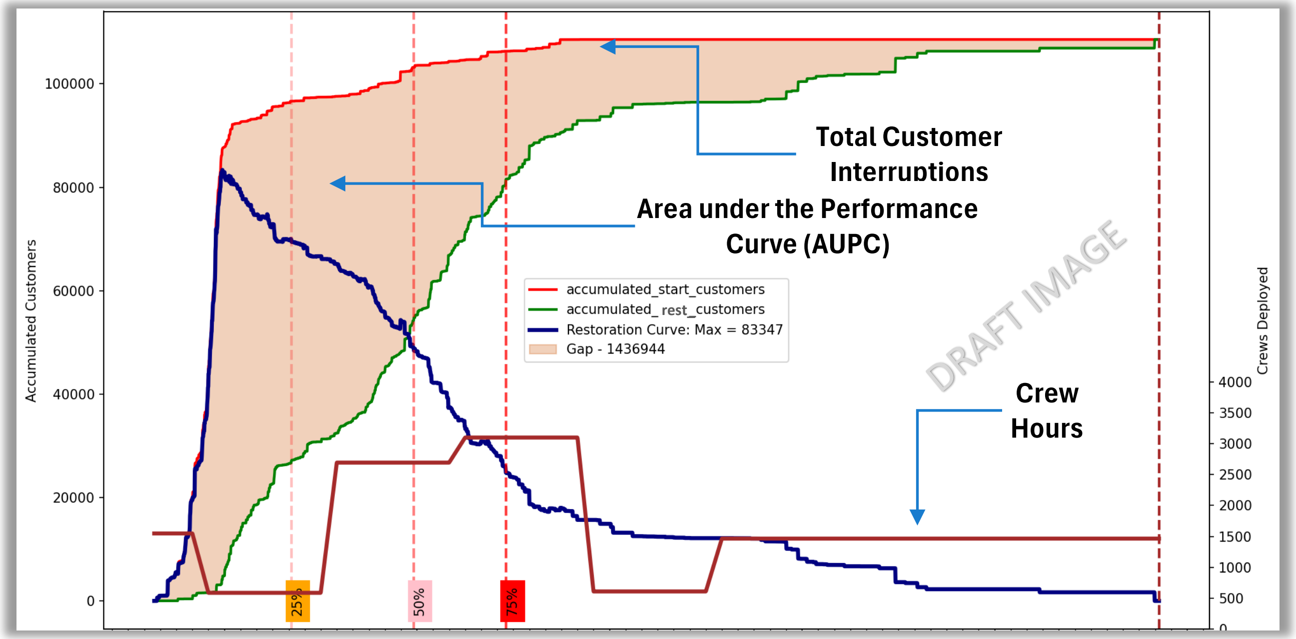
Threshold "Y" is calculated based on data analytics of small, medium, large, and significant size storm with 5 year moving average data. Details are explained in IEEE distribution resiliency guide.

REPAIR Metric

- **Total Outages** – Intensity of the storm [Non-controllable]
- **Max Customer Interruptions** – Indicator of crew efforts in curbing maximum degradation
  - **Semi-Controllable** – better human performance, lower CI.
  - But for severe events where all outages happen at the head end of the chart, there will be significant lag in start of restoration by crews
- **Area under the Restoration Curve** – Indicator tracking restoration efforts vs emerging outages. Smaller the area under the curve better restoration performance [Controllable – Better human performance, lower AUPC]
- **Crew Hours** – Total hours spent on the field by crew [Controllable – Better human performance, lower crews needed for 100% restoration]
- **Storm duration**
- **Full restore time** – Controllable but already captured by AUPC



If Customer Interruptions is the resilience indicator in this figure, then the operational resilience is enabled by restoration efforts, both automated and by crew work



Sample Calculations for 9 Storms

- Wide range – compression required – Use Log scale
- $$\text{REPAIR} = \log\left(\boxed{\frac{\text{Crew Hours}}{\text{Outages}}} \times \boxed{\frac{\text{AUPC}}{\text{CI}}}\right)$$

  Restoration Effectiveness (RE) + Area Index Resiliency (AIR)

- Insights:
  - Lower crew
  - Lower max customer interruptions
  - Lower AUPC

Outages (n)	Crew Hours	RE	AUPC	CI	AIR	REPAIR
1,536	142,172	1.97	1,135,907	176,929	0.81	2.77
1,126	49,549	1.64	370,417	107,578	0.54	2.18
1,267	42,399	1.53	282,653	128,132	0.34	1.87
216	31,866	2.17	31,786	28,724	0.04	2.21
2,588	118,405	1.66	2,221,044	208,613	1.03	2.69
850	75,411	1.95	753,380	88,923	0.93	2.88
457	30,250	1.82	91,268	49,497	0.27	2.09
347	30,816	1.95	80,027	38,053	0.32	2.27
1,129	49,443	1.64	576,270	111,156	0.72	2.36

Average	**2.37**
Standard Deviation	0.32
Range	2.05 -2.69

GridCo Partners

Case Studies

Case Study 1: Illinois

- Storm 1 and 2 are comparable in nature
- Storm 1 was hit in a lower DA Penetration area
- ACI is lower for Storm 2
- Storm 2 hit at 8 PM vs Storm 1 was at 5 PM

$$X = \frac{\sum \text{Customers Without Power for More than Z hours}}{\text{Avoided Sustained CI by Automation /Hardening + Sustained CI}}$$

$$SIRI = \frac{\text{Avoided Sustained Customer Interruption (CI) by Automation/Hardening}}{\text{Avoided Sustained CI by Automation/Hardening + Sustained CI}}$$

Description	Storm 1	Storm 2	Storm 3
Start Storm Date Time	6/26/20 16:53	6/20/21 20:18	9/7/21 13:02
End Storm Date Time	6/27/20 18:51	6/21/21 17:34	9/8/21 6:13
Sustained Outage Count	575	527	420
Sustained Cust Inter	57,504	53,156	40,946
Max Outage (Hours)	75.7	93.1	39.4
DA ACI	30537	26511	30372
X : Restored >12Hrs (w/ ACI)	4.18%	8.01%	3.67%
SIRI	35%	33%	43%
Restored ≤12Hrs	93.60%	88.00%	93.60%
Major Causes	HAIL, LIGHTNING, RAIN, WIND	RAIN, TORNADO, WIND	HAIL, LIGHTNING, RAIN, WIND

Case Study 1: Illinois

Sequential vs. Multiple Storm Waves

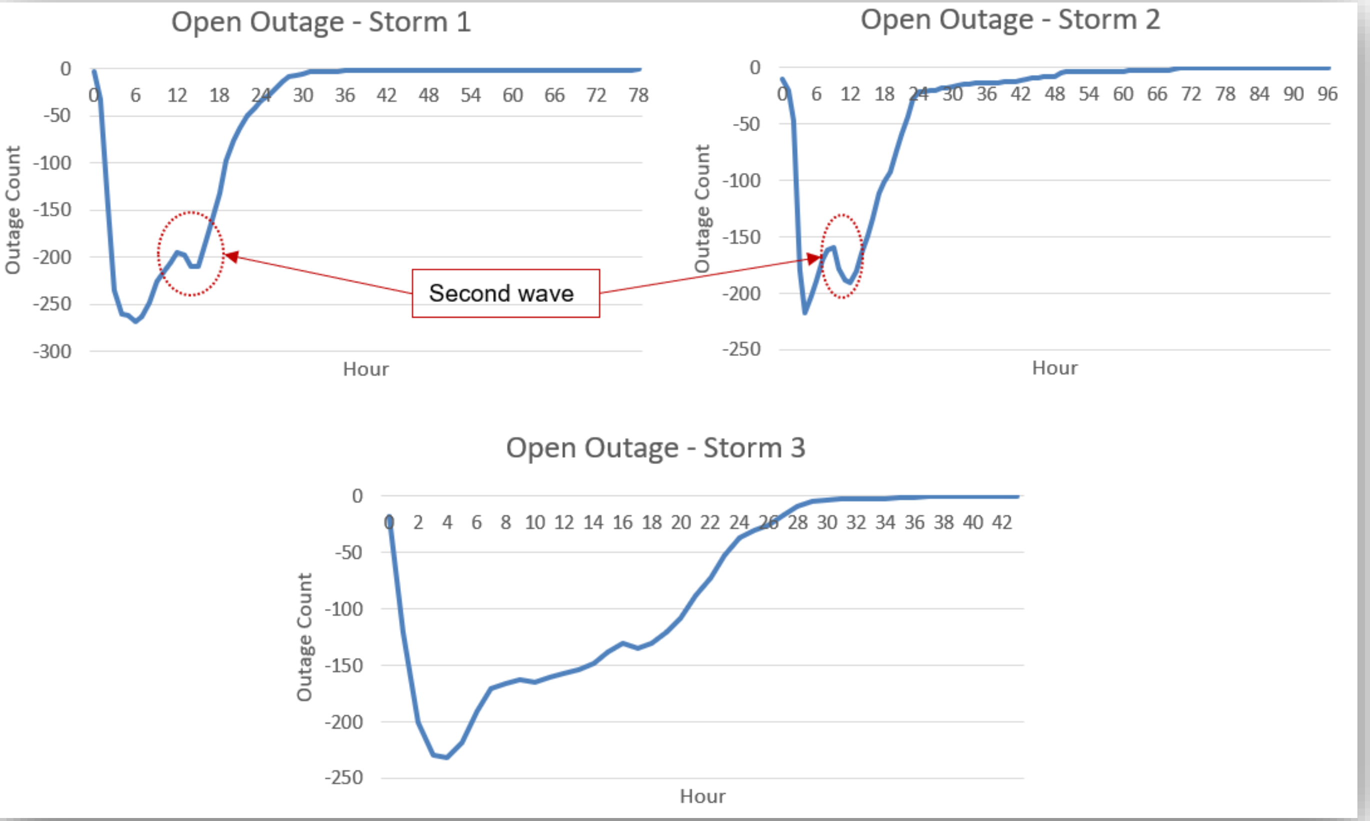
- Surge in outages after 10 hours, indicating a second wave of storm, not just initial tripping/fuse events

Impact on Restoration Planning

- Multiple storm waves disrupt restoration, complicating crew deployment and resource management during recovery

Timing and Automation Matter

- Faster deployment in the first 12 hours and higher automation (e.g., DA devices) significantly improve performance against ComEd's resiliency targets



Case Study 2: Midwest & East Coast

What Was Done

- Utility tested IEEE's Restoration Effectiveness, which measures % of customers out >12 hours during storms.
- Applied across 5 regions using real utility data from 2018–2023.

Storms classified by severity using IEEE 1366 TMED multipliers

- *Small*: 1.0–1.5 | *Medium*: 1.75–2.5
- *Large*: 2.75–3.5 | *Significant*: 3.75+

Key Results

- More than 70–90% of storms across most regions in 2023 performed better than the 5-year baseline.
- Backbone device analysis (reclosers, breakers, switches) showed even better resiliency scores, especially for small/medium storms.
- High variability in performance tied to storm type and location (e.g., rural vs. urban, weather-driven vs. equipment failure).

Case Study 2: Midwest & East Coast

Date	Outages	Customers Out	>12hr Outages	% Saved via Self-Healing	X : Restored >12Hrs (w/ ACI)
Jan 7, 2023	88	10,082	4,638	0%	**46%** (very poor)
Apr 7, 2023	310	39,922	20	15%	**0.04%** (excellent)

Jan 7: Transformer failure in rural area with no backfeed capability led to high outage duration.

Apr 7: Widespread storm but automation saved 7,000+ customers, leading to excellent score.

Case Study 3: Florida

Hurricane	Year	Grid Strategy	% Feeders Hardened	Smart Devices (Reclosers)	50% Restored	100% Restored	Avg. Outage
#1	Pre-Resiliency	None	0%	None	3 days	13 days	3.5 days
#2	Pre-Resiliency	None	0%	None	5 days	18 days	5.4 days
#3	12 yrs later	Storm hardening + Reclosers	27%	Moderate	**1 day**	10 days	2.1 days
#4	17 yrs later	Storm hardening + More Reclosers	58%	**Doubled**	**1 day**	**8 days**	**1.5 days**

Case Study 3: Florida

Post-Hurricane #2, launched aggressive storm hardening

- Upgraded poles and feeders to high wind-load standards
- Reduced pole damage significantly (from 12,400 to 3,200)

Installed smart grid tech (self-healing reclosers)

- Avoided 546k interruptions (Hurricane #3)
- Avoided 405k interruptions (Hurricane #4)

Improved resource deployment and grid design

- Cut average outage duration by over 70%
- Achieved 50% restoration in 1 day, even for stronger storms

Case Study 4: Northeast

Evaluated Gray Sky Day (GSD) metric using divisional-level analysis, not company-wide, due to varied geography and weather patterns.

Used airport weather stations

Yellow
- Average temperature between 80 and 85 degrees
- Average temperature between 0 and -5 degrees
- Average sustained wind speed between 25 and 30 MPH
- Average of one-hour wind gust between 25 MPH and 30 MPH

Orange
- Average temperature between 85 and 90 degrees
- Average temperature between -5 and -10 degrees
- Average sustained wind speed between 30 and 35 MPH
- Average of one-hour wind gust between 30 MPH and 35 MPH

Red
- Average temperature greater than 90 degrees
- Average temperature less than -10 degrees
- Average sustained wind speed >= 35 MPH
- Average of one-hour wind gust >= 30 MPH

Metric Definition

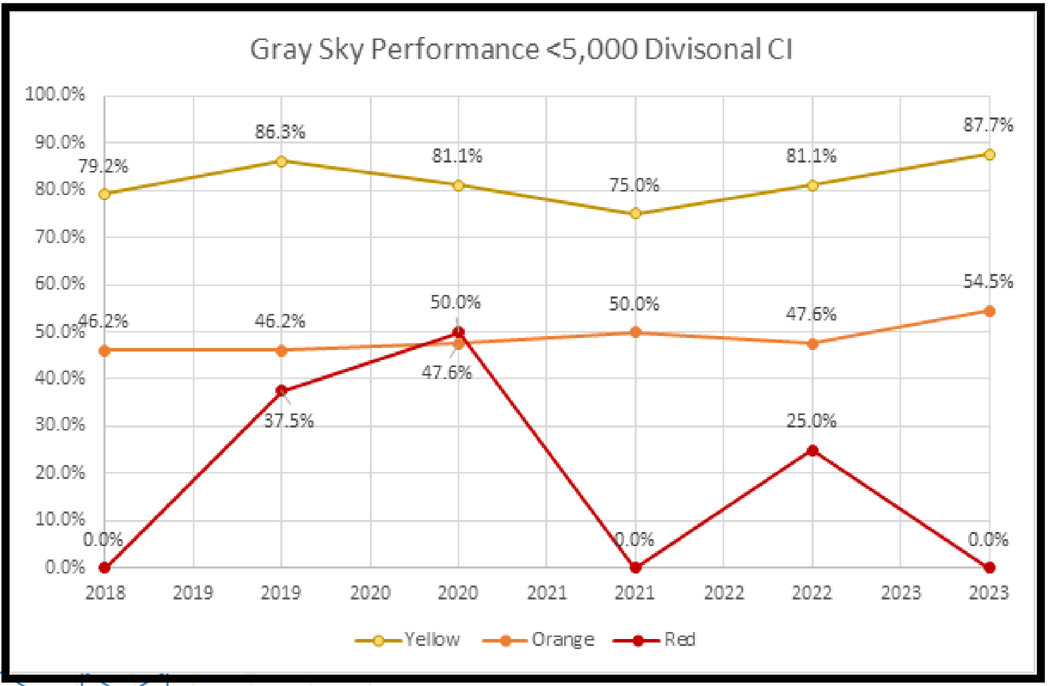
- Success = % of GSDs where <5,000 customers were interrupted
- Target value: 5,000 Customer Interruptions (CI)
  (based on 5-year average daily CI incl. major storms from 2018–2022)

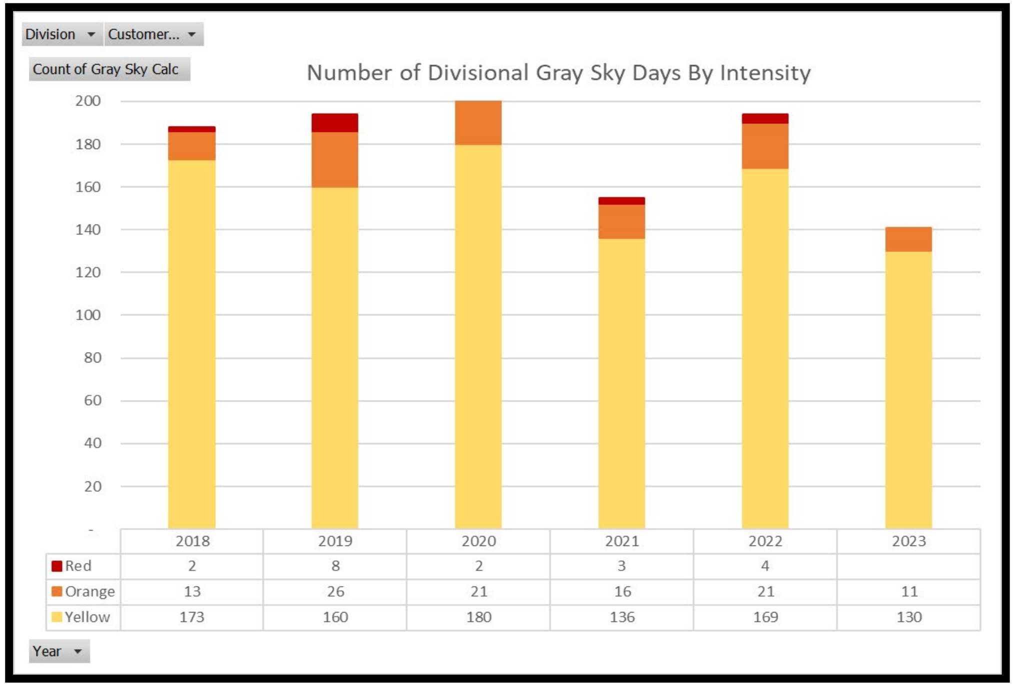
Case Study 4: Northeast

All Gray Sky Days	Yellow	Orange	Red	Grand Total
2018	173	13	2	188
2019	160	26	8	194
2020	180	21	2	203
2021	136	16	3	155
2022	169	21	4	194
2023	130	11		141
Total	**948**	**108**	**19**	**1,075**

<5,000 CI Gray Sky Days	Yellow	Orange	Red	Grand Total
2018	137	6		143
2019	138	12	3	153
2020	146	10	1	157
2021	102	8		110
2022	137	10	1	148
2023	114	6		120
Total	**774**	**52**	**5**	**831**

%	Yellow	Orange	Red	Grand Total
2018	79.2%	46.2%	0.0%	76.1%
2019	86.3%	46.2%	37.5%	78.9%
2020	81.1%	47.6%	50.0%	77.3%
2021	75.0%	50.0%	0.0%	71.0%
2022	81.1%	47.6%	25.0%	76.3%
2023	87.7%	54.5%	-	85.1%
Total	**81.6%**	**48.1%**	**26.3%**	**77.3%**





Case Study 4: Northeast

Key Results

- 2023 performance >70% success rate across all divisions
- Year-over-year improvement since 2018 in Yellow & Orange GSDs
- Red GSDs lacked sufficient data for conclusions

Challenges & Observations

- Limited localized weather station data (mostly from airports) reduced ability to classify more days as GSDs
- Variability in data granularity across divisions
- Results show system resiliency investments are paying off

Next Steps

- Incorporate longer weather and outage history for better trend detection
- Enhance weather station network granularity
- Continue using this metric to guide targeted infrastructure upgrades

GridCo Partners

PNNL - GridCo Resiliency Valuation

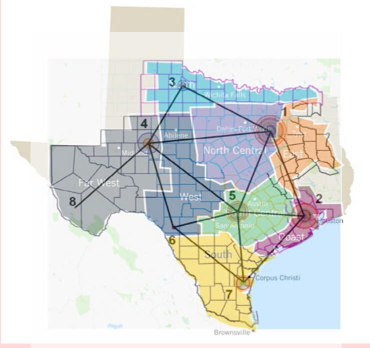
DSO-RISE Study

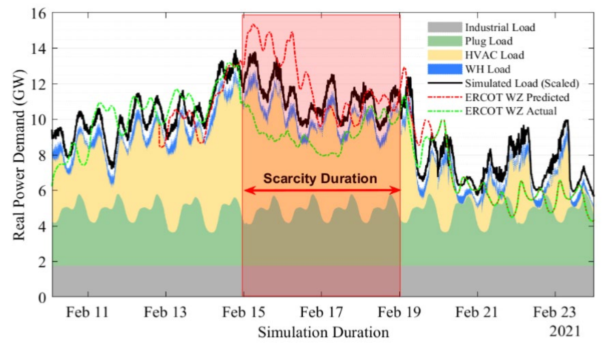
DSO RISE

Quantifying demand in extreme weather

GridLAB-D

HELICS





Modeling and simulation platform to reflect realistic conditions during extreme weather conditions

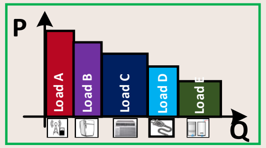
Resilience Enhancement Mechanisms

Meter Data Historian

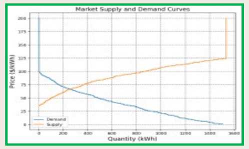
Switching Schemes

Comfort-Levels

Analytics

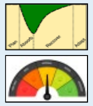


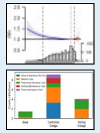
Customer Bids



Emergency Retail Markets

Implementation of Advanced Outage Management approaches including (1) Controlled Outages, (2) Direct Load Control, & (3) DER Coordination Mechanisms for Resilience enhancement





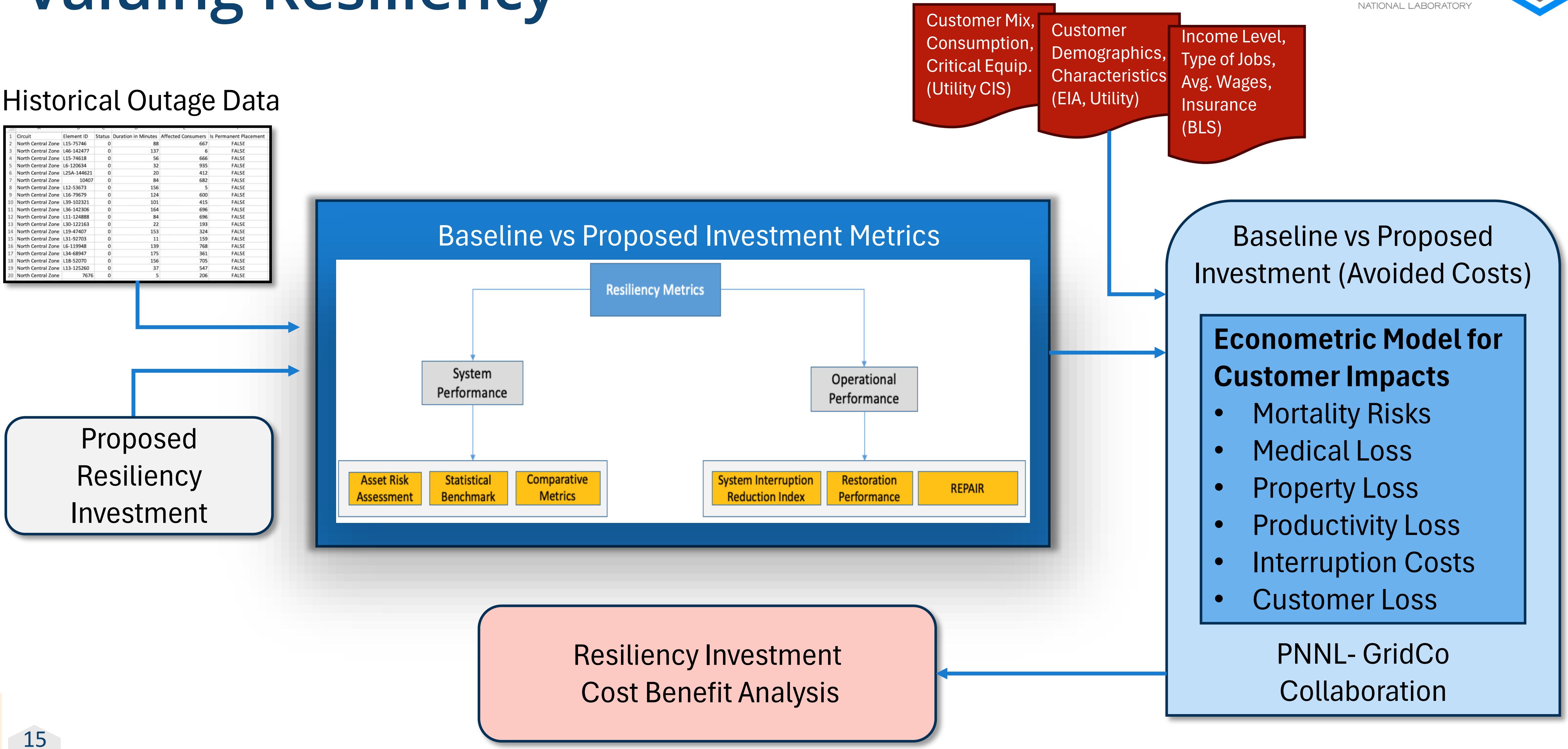
VSL (mortality)
Medical Costs
Cost of Interruption
Property Loss

Damage Estimation

Developed method for calculating cost of outages including mortality risks, productivity & property damage

Determine the cost of deployment for resilience enhancement mechanisms

Valuing Resiliency



	Circuit	Element ID	Status	Duration in Minutes	Affected Consumers	Is Permanent Placement
2	North Central Zone	L15-75746	0	88	667	FALSE
3	North Central Zone	L46-142477	0	137	6	FALSE
4	North Central Zone	L15-74618	0	56	666	FALSE
5	North Central Zone	L6-120634	0	32	935	FALSE
6	North Central Zone	L25A-144621	0	20	412	FALSE
7	North Central Zone	10407	0	84	682	FALSE
8	North Central Zone	L12-53673	0	156	5	FALSE
9	North Central Zone	L16-79679	0	124	600	FALSE
10	North Central Zone	L39-102321	0	101	415	FALSE
11	North Central Zone	L36-142306	0	164	696	FALSE
12	North Central Zone	L11-124888	0	84	696	FALSE
13	North Central Zone	L30-122163	0	22	193	FALSE
14	North Central Zone	L19-47407	0	153	324	FALSE
15	North Central Zone	L31-92703	0	11	159	FALSE
16	North Central Zone	L6-119948	0	139	768	FALSE
17	North Central Zone	L34-68947	0	175	361	FALSE
18	North Central Zone	L18-52070	0	156	705	FALSE
19	North Central Zone	L13-125260	0	37	547	FALSE
20	North Central Zone	7676	0	5	206	FALSE

Takeaways and Next Steps

ComEd has been utilizing two metrics, restoration performance and Gray Sky day, since 2020.

These metrics have allowed ComEd to concentrate on system enhancements and improvements in resiliency.

Through the IEEE Distribution Resiliency Working Group, three other utilities have adopted the restoration performance and Gray Sky day metrics for their systems.

The final draft of the guide will be submitted for review and ballot at IEEE in 2025.

GridCo & PNNL are developing Resiliency Valuation tool to evaluate investment scenarios in rate cases.

GridCo Partners

Navigating the Future of the Grid

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Next Steps

- Recordings and Presentations Posted to Event Pages
- Staff Report With Recommendations due October 31, 2025

PowerPoint Template Instructions