Resilient Power Grids: Strategically Undergrounding Powerlines

March 22, 2022

Stay tuned…we will begin at approximately 1:00 PM ET

U.S. DEPARTMENT OF ENERGY | OFFICE OF ELECTRICITY

Resilient Power Grids: Strategically Undergrounding Powerlines

March 22, 2022

1:00 PM - 4:30 PM ET

U.S. DEPARTMENT OF ENERGY | OFFICE OF ELECTRICITY

Welcome and Housekeeping

Questions?

If you have technical questions – please put them in the chat box for the host.

Please submit your questions in the Q&A box.
Reference the speaker or topic.

U.S. DEPARTMENT OF ENERGY | OFFICE OF ELECTRICITY

Patricia Hoffman

Acting Director,

Grid Deployment Office

U.S. DEPARTMENT OF ENERGY | OFFICE OF ELECTRICITY

Peter Larsen

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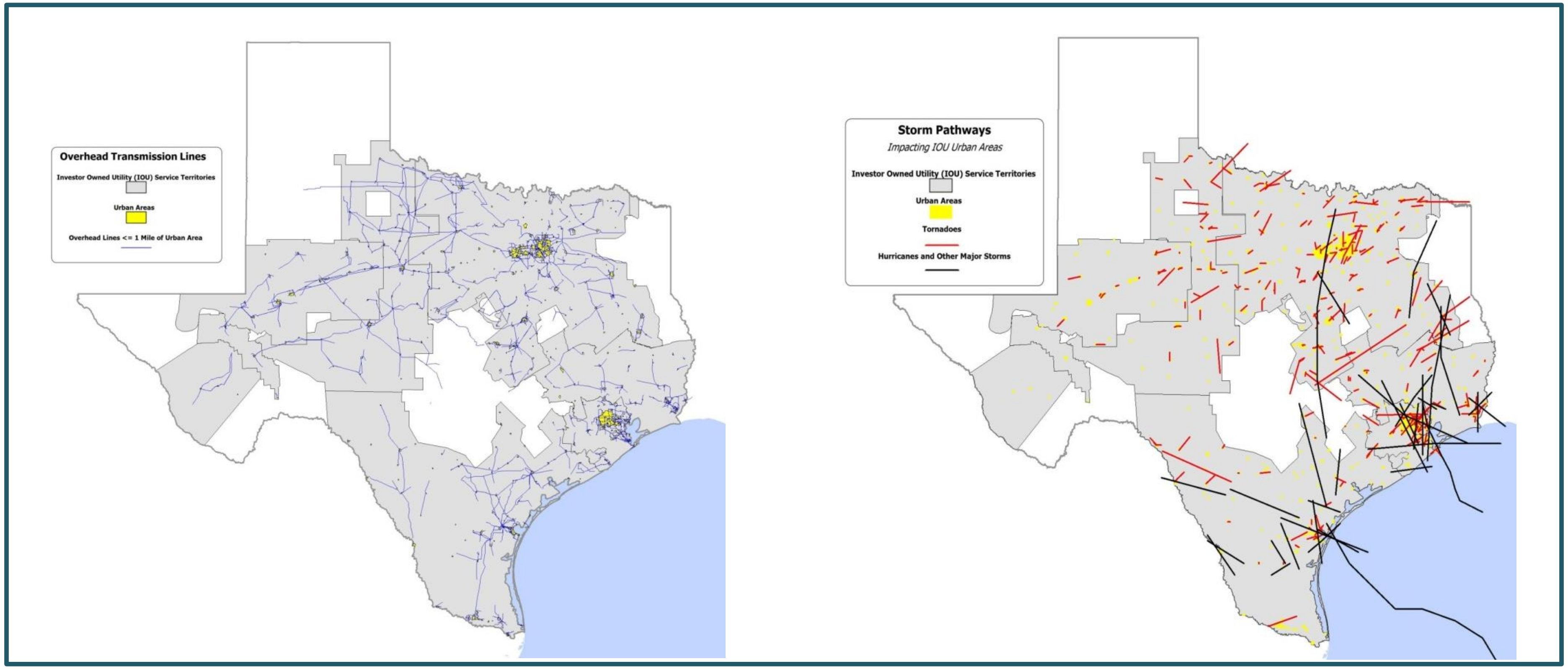
Estimating the Value of Undergrounding T&D Lines

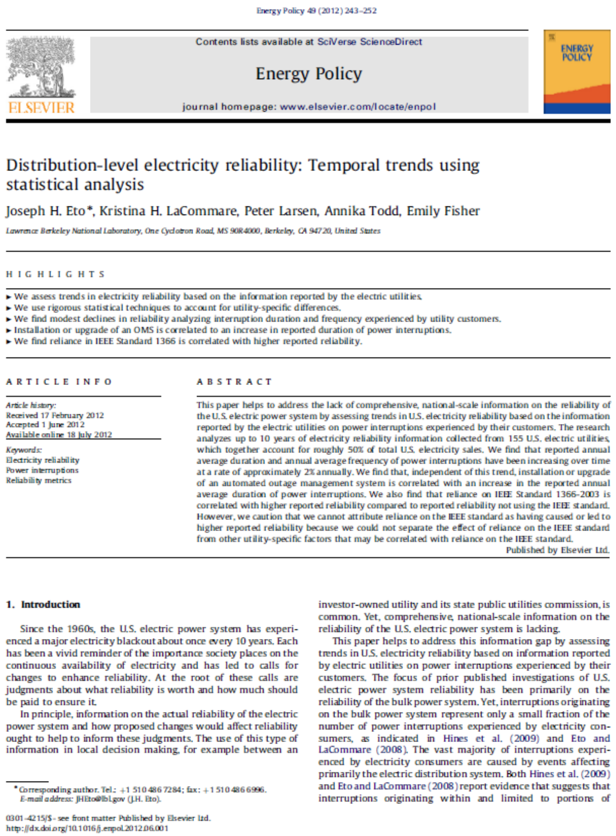


Peter Larsen

March 22, 2022 ▪ Strategically Undergrounding Power Lines Webinar

Background

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



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Energy Policy

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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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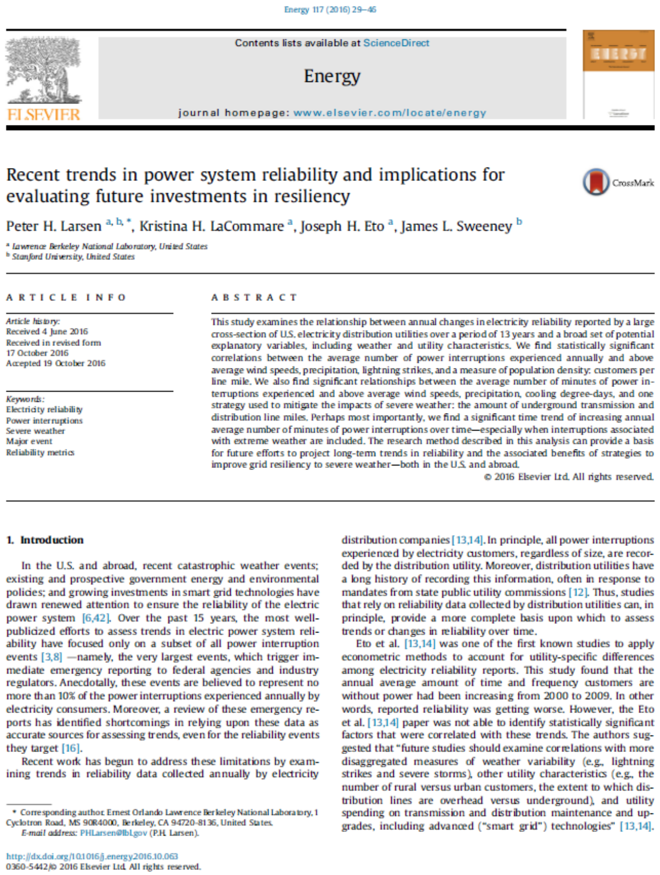

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Recent trends in power system reliability and implications for evaluating future investments in resiliency

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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

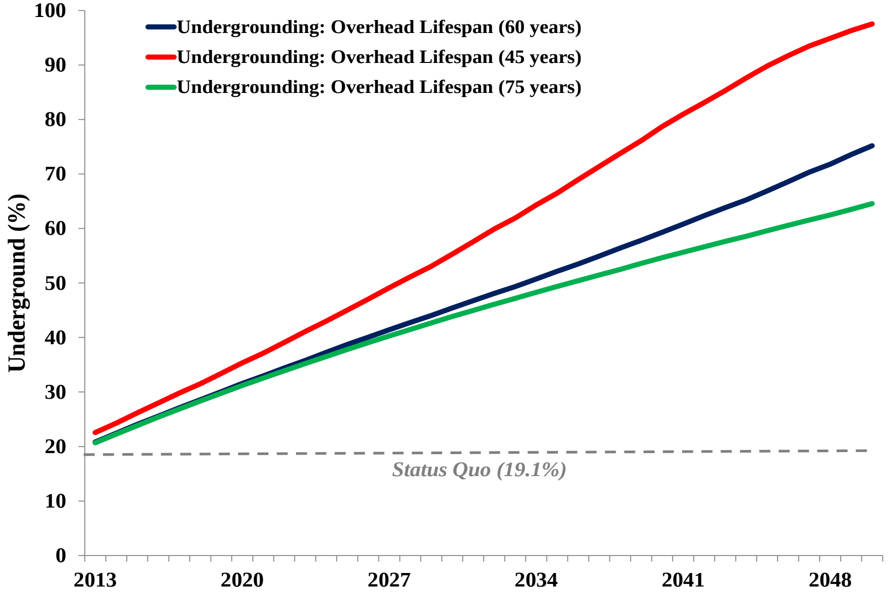
Analysis framework: Texas IOUs (cont.)

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**

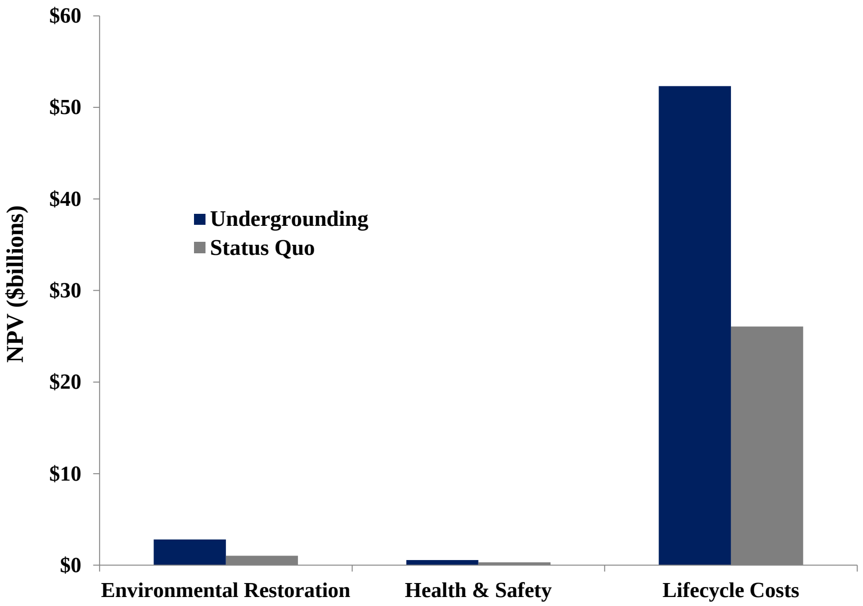
Key:

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

Estimated costs

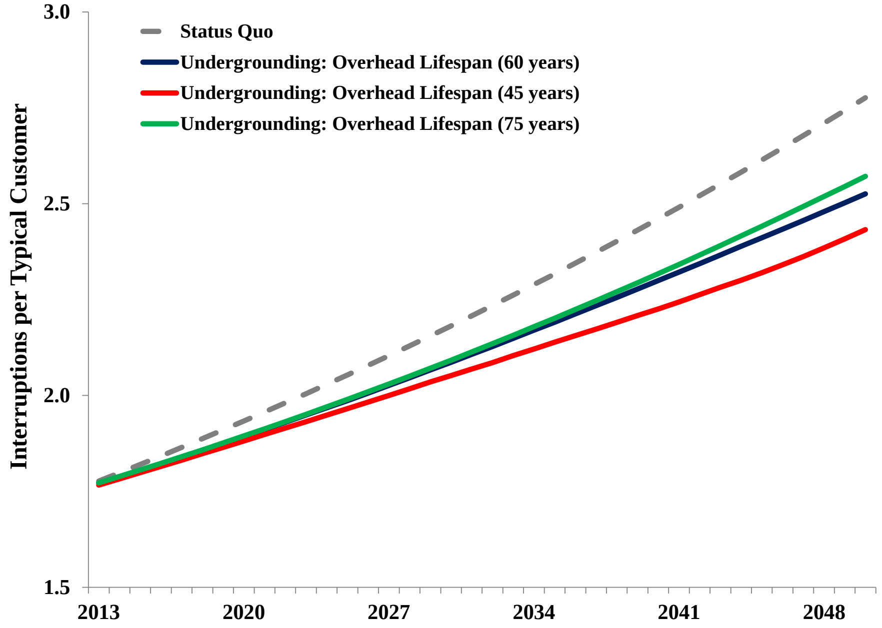


- Underground mileage share increasing over time under alternative overhead lifespan assumptions

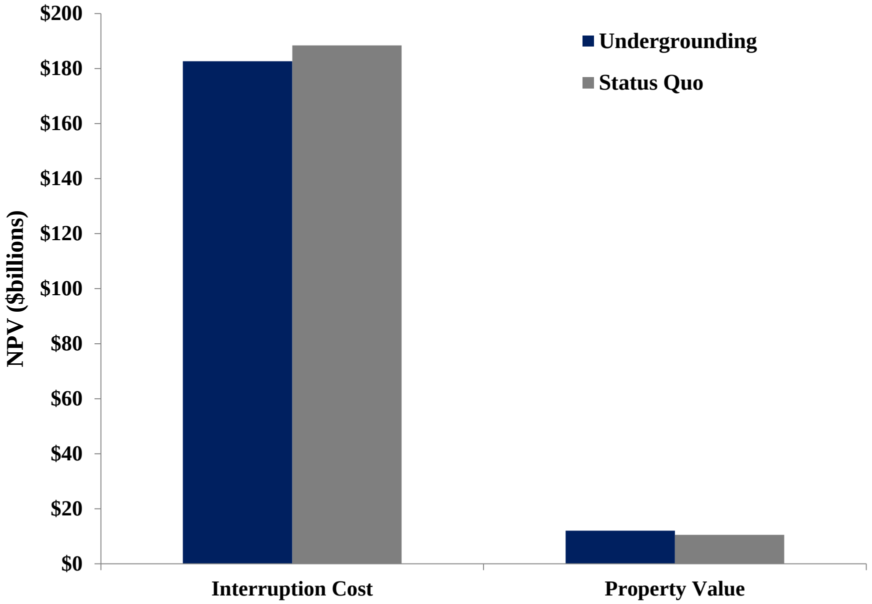


- NPV of undergrounding and status quo costs ($2012)

Estimated benefits

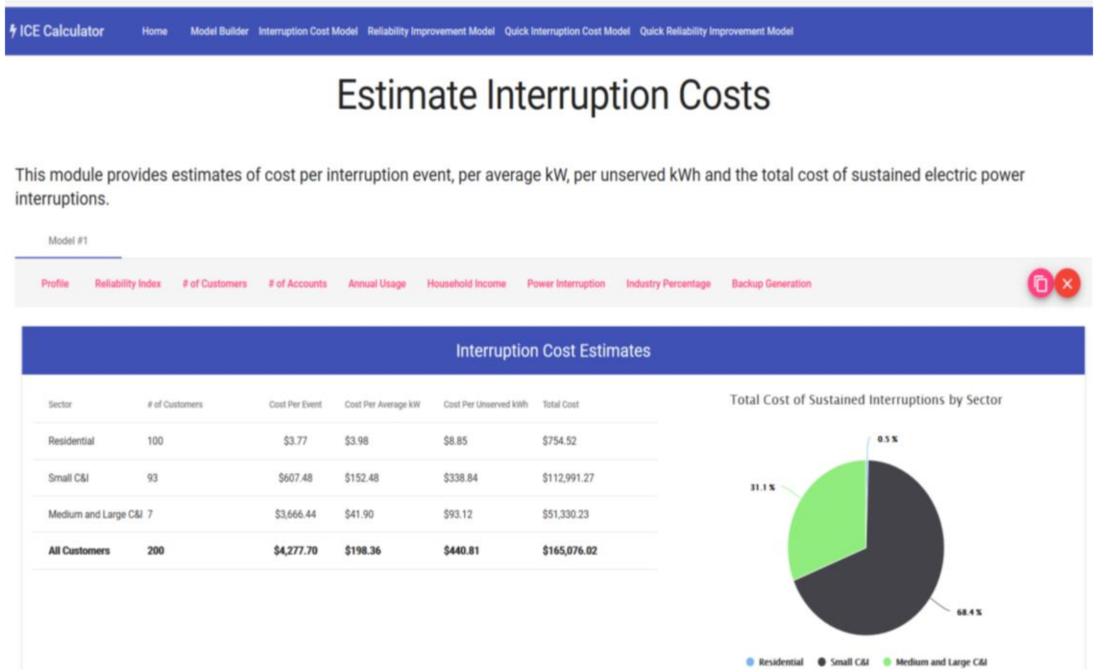


- Projected power outages over time under alternative overhead lifespan assumptions



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

Estimated benefits (cont.)



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

http://www.icecalculator.com/

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

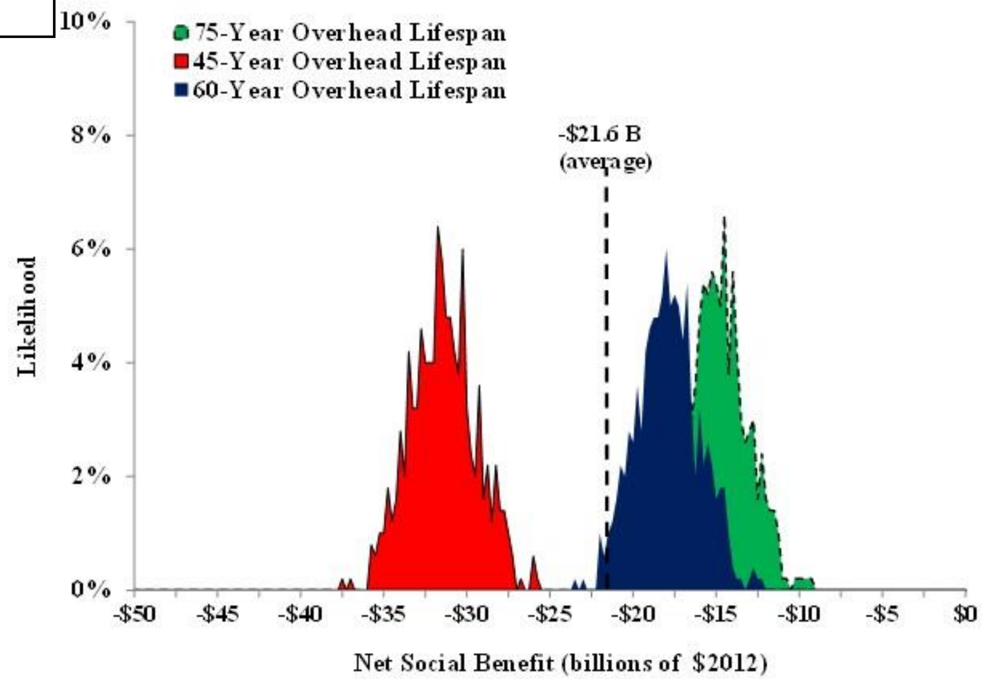
- Utility and other stakeholders often use the ICE Calculator to estimate the benefits of avoiding future (or past) power interruptions

Net social loss

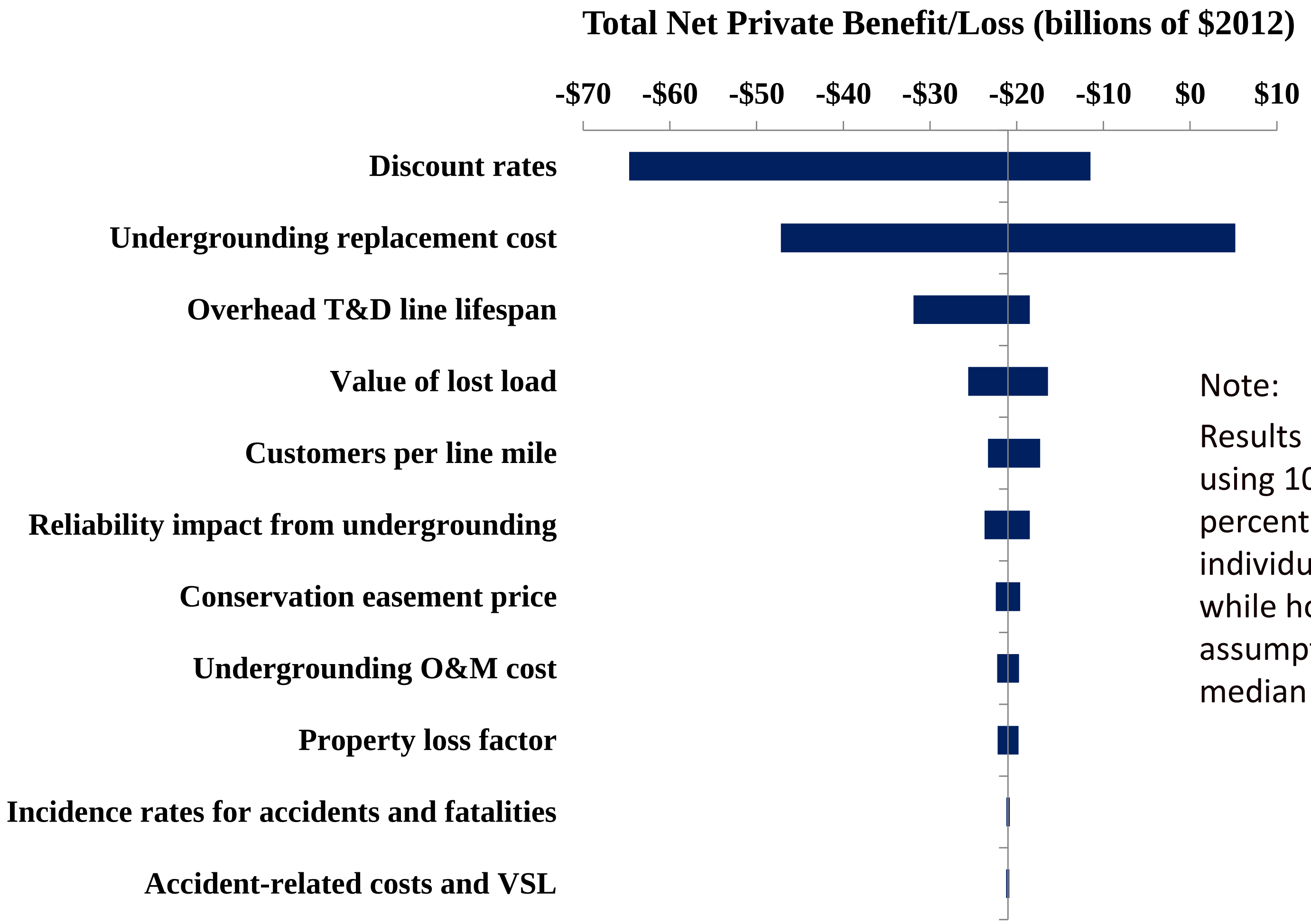
Impact Category	Undergrounding	Status Quo	Net Cost ($billions)
Environmental restoration	$2.8	$1.0	$1.8
Health & safety	$0.56	$0.31	$0.2
Lifecycle costs	$52.3	$26.1	$26.3
Total net costs (Undergrounding)			$28.3
Impact Category	**Undergrounding**	**Status Quo**	**Net Benefit ($billions)**
Interruption 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



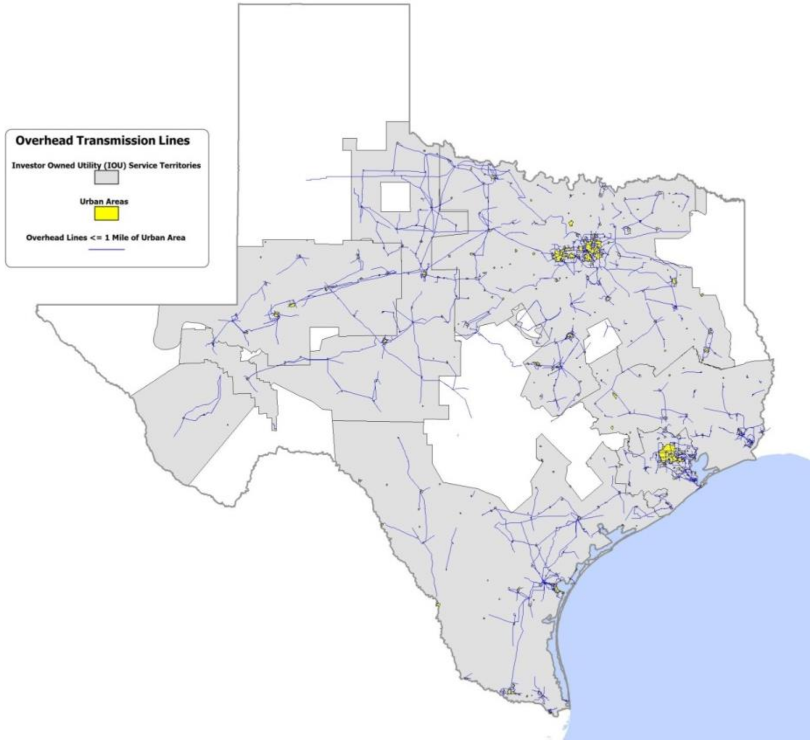
Note:

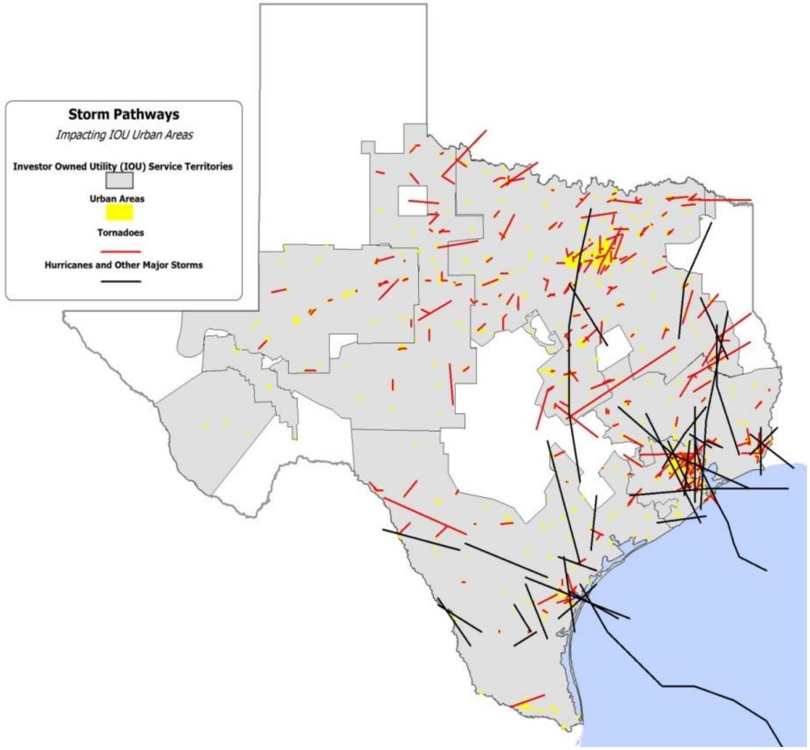
Results generated by using 10th (90th) percentile value for individual assumption while holding all other assumptions constant at median value.

- 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**



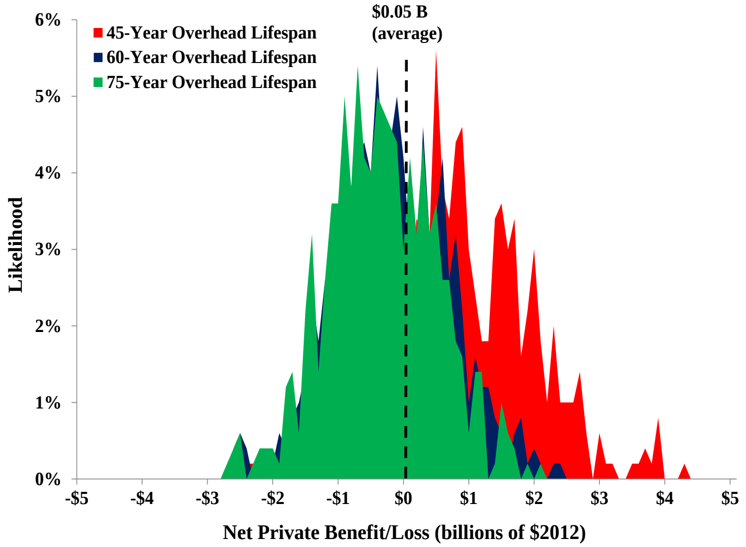


- *What are minimum conditions necessary for a targeted undergrounding initiative to have positive net benefits?*

Possibility of net benefits (cont.)

Texas policymakers <u>should</u> 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.

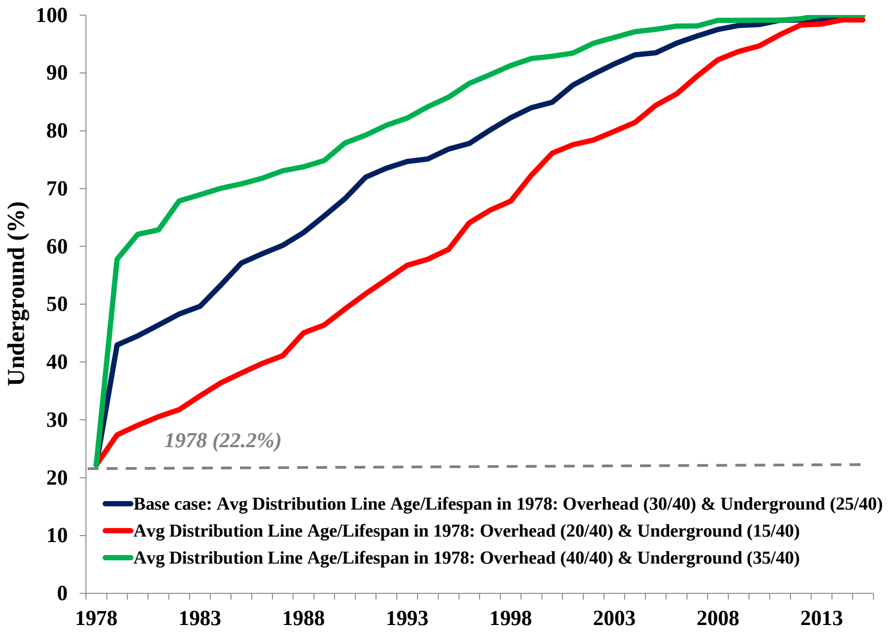
Analysis framework: Cordova case (cont.)

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]

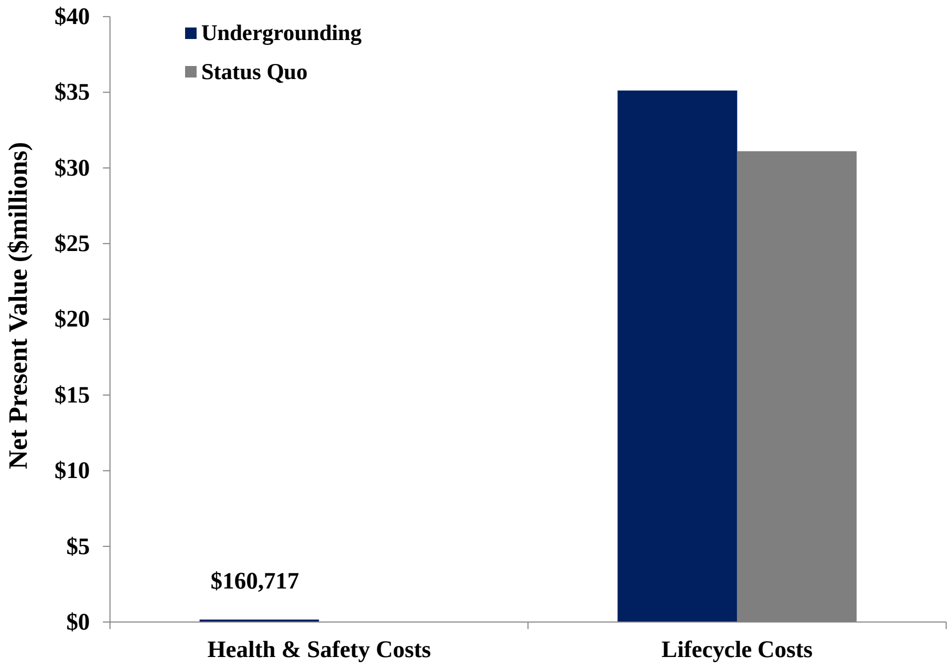
Key:

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

Estimated costs

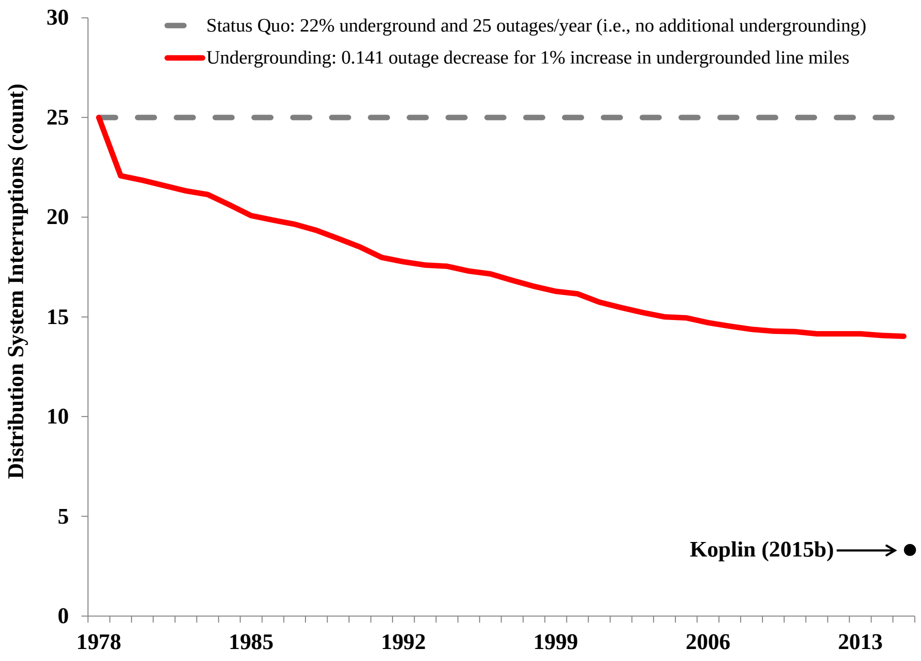


- NPV of undergrounding and status quo costs ($2015)

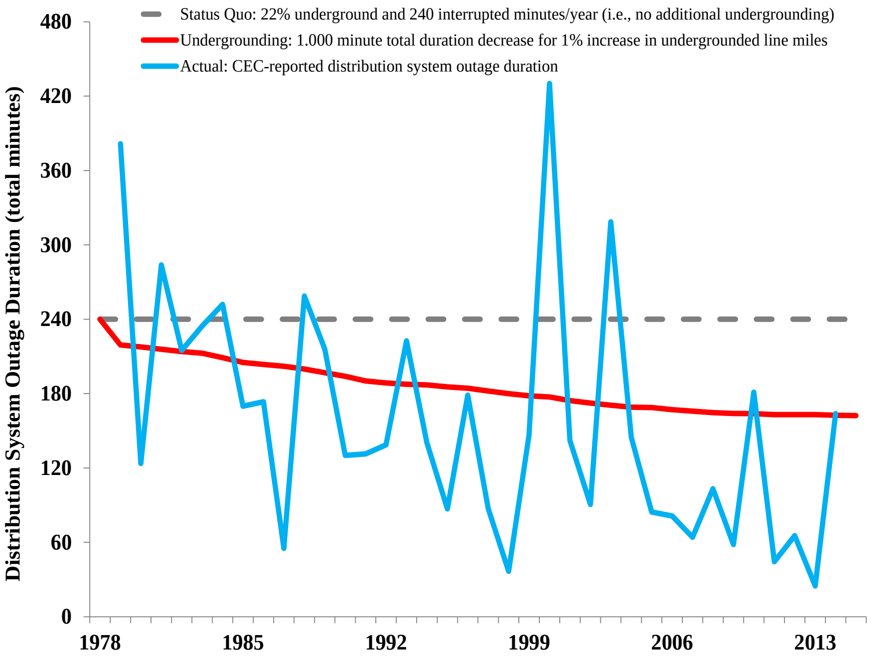


Estimated benefits

Customer interruptions



Interruption minutes

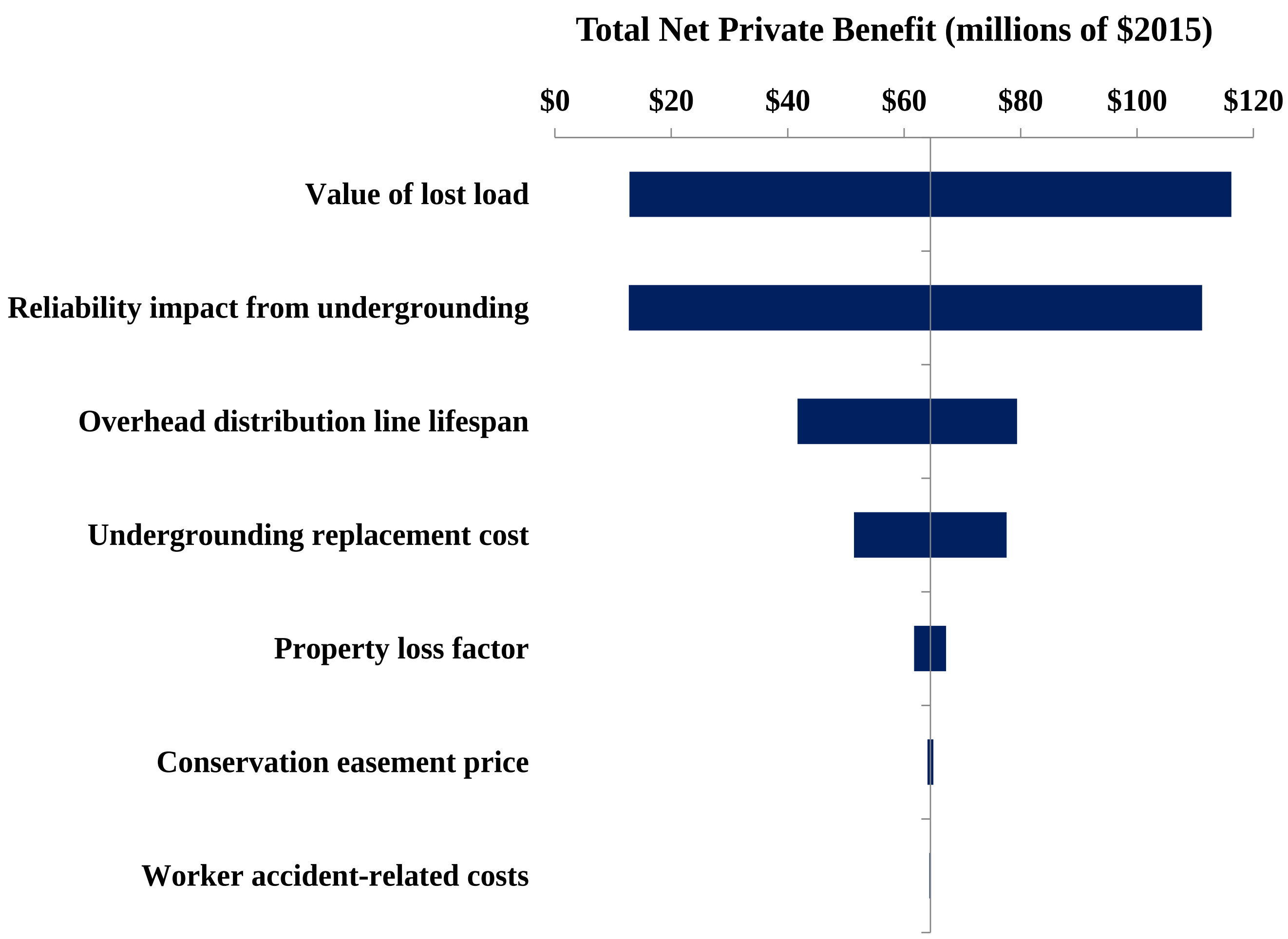


Net social benefit

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**

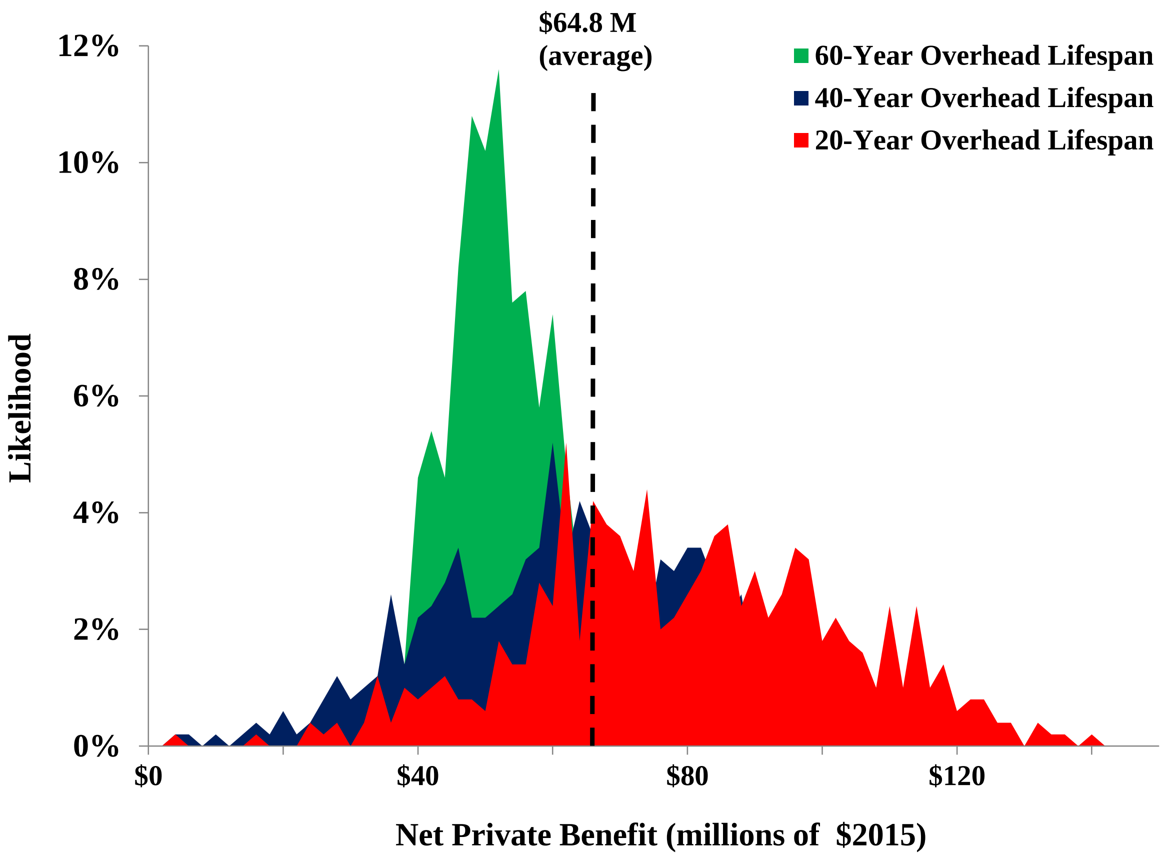
NOTE: **Reliability benefits, although large, are not necessary for cost-effectiveness**.

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

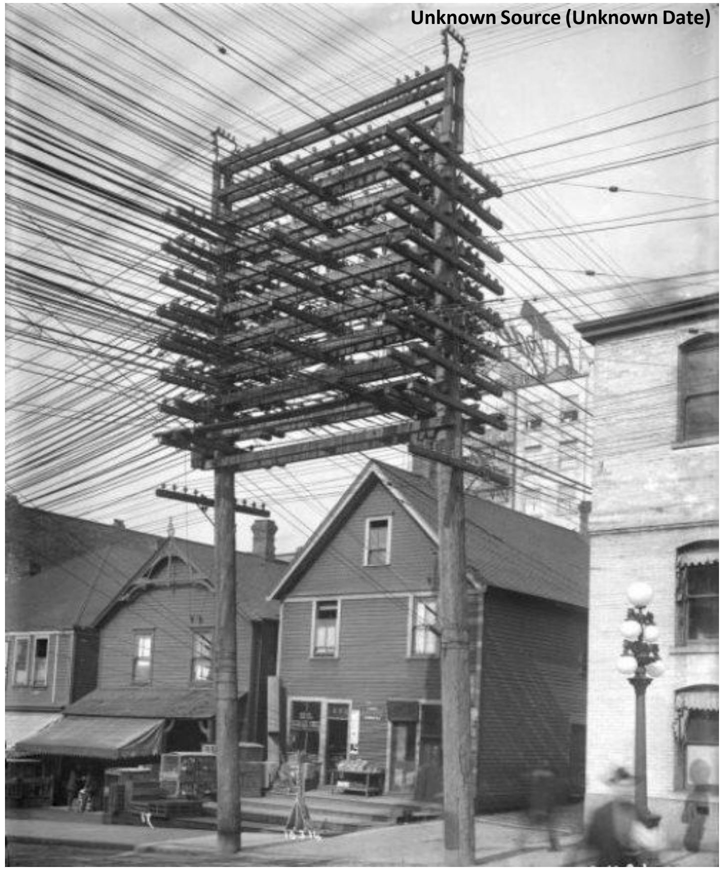
- Generally **assumed that the costs of undergrounding transmission and distribution lines far exceed the benefits** from avoided outages

- 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 (10th %)**	**Base case value (50th %)**	**Maximum value (90th %)**	**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…

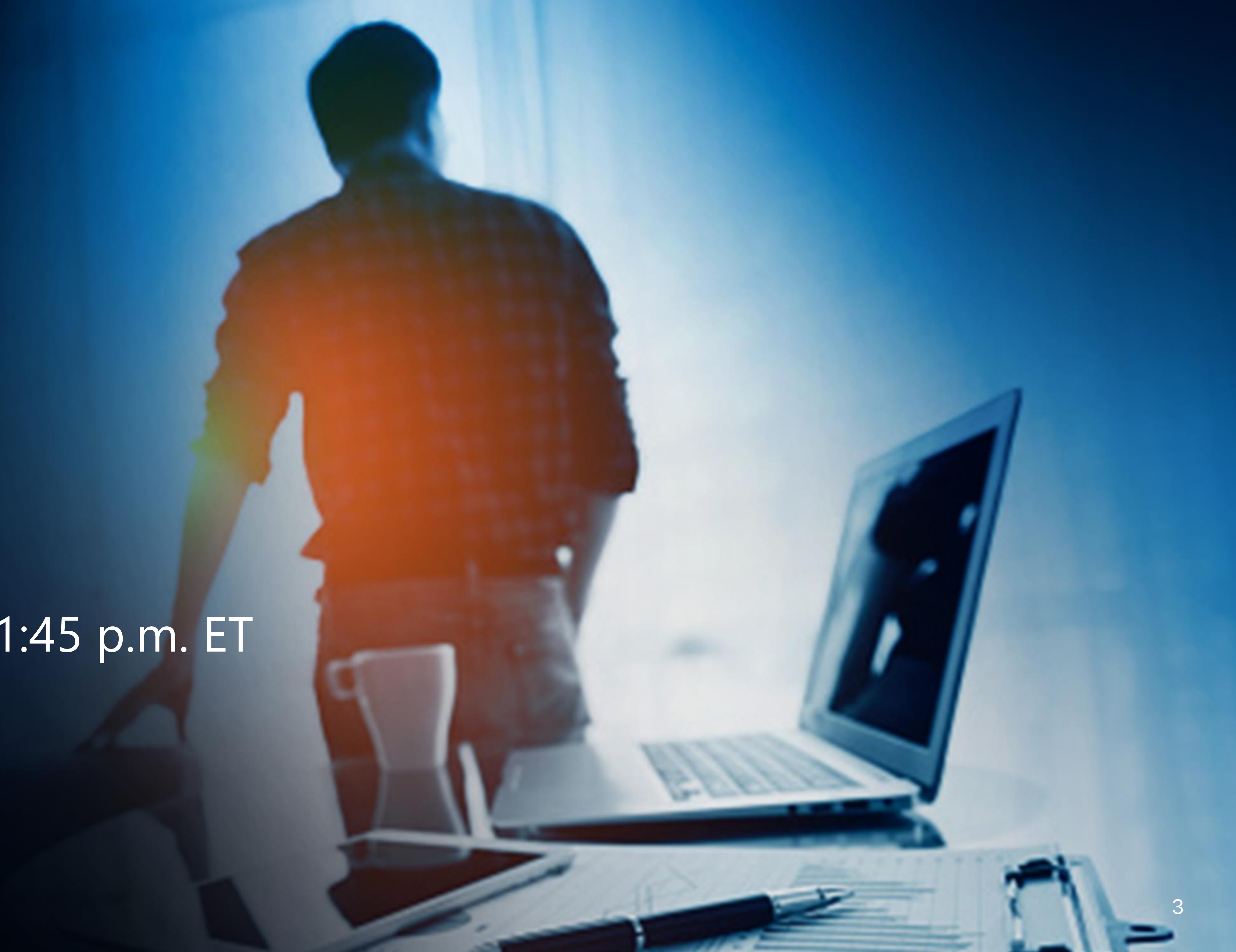
		Range			Impact Category				
#	**Sensitivity/ scenario analysis**	**Minimum value (10^{th} %)**	**Base case value (50^{th} %)**	**Maximum value (90^{th} %)**	**Lifecycle assessment (cost)**	**Avoided outages (benefit)**	**Aesthetics (benefit)**	**Worker safety (cost)**	**Ecosystem restoration (benefit)**
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				*	

Questions?

U.S. DEPARTMENT OF ENERGY | OFFICE OF ELECTRICITY

Break

We will begin at 1:45 p.m. ET

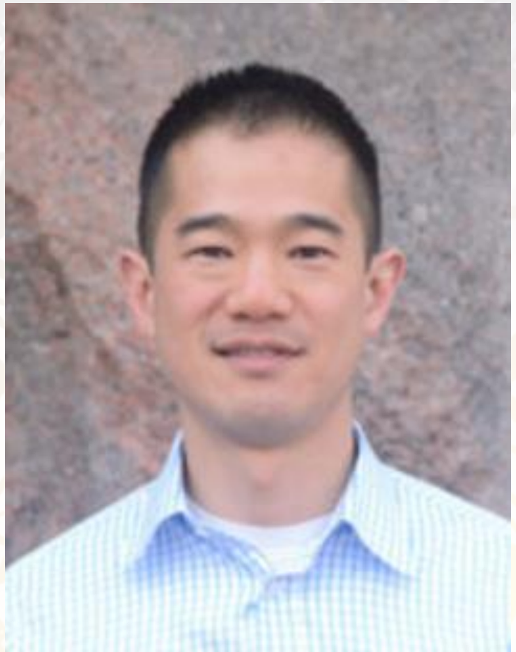


Experiences from the Field

Eric Hsieh

Director, Grid Components and Systems

Office of Electricity



U.S. DEPARTMENT OF ENERGY | OFFICE OF ELECTRICITY

Arie Makovoz

Technical Expert; Transmission Line Engineering Department

Con Edison

Making a Resilient Power Grid: Strategically Undergrounding Power Lines DOE Workshop - March 22, 2022

Arie Makovoz – Technical expert

Transmission Line Engineering Department

conEdison

Con Edison Transmission System

- **754 miles Underground**
- **335 UG Feeders**
  - Most feeders are pipe-type
  - Average Age – 47 years
  - Oldest feeders are more than 70 years old and still in service

- **569 miles Overhead**
- **51 OH Lines**

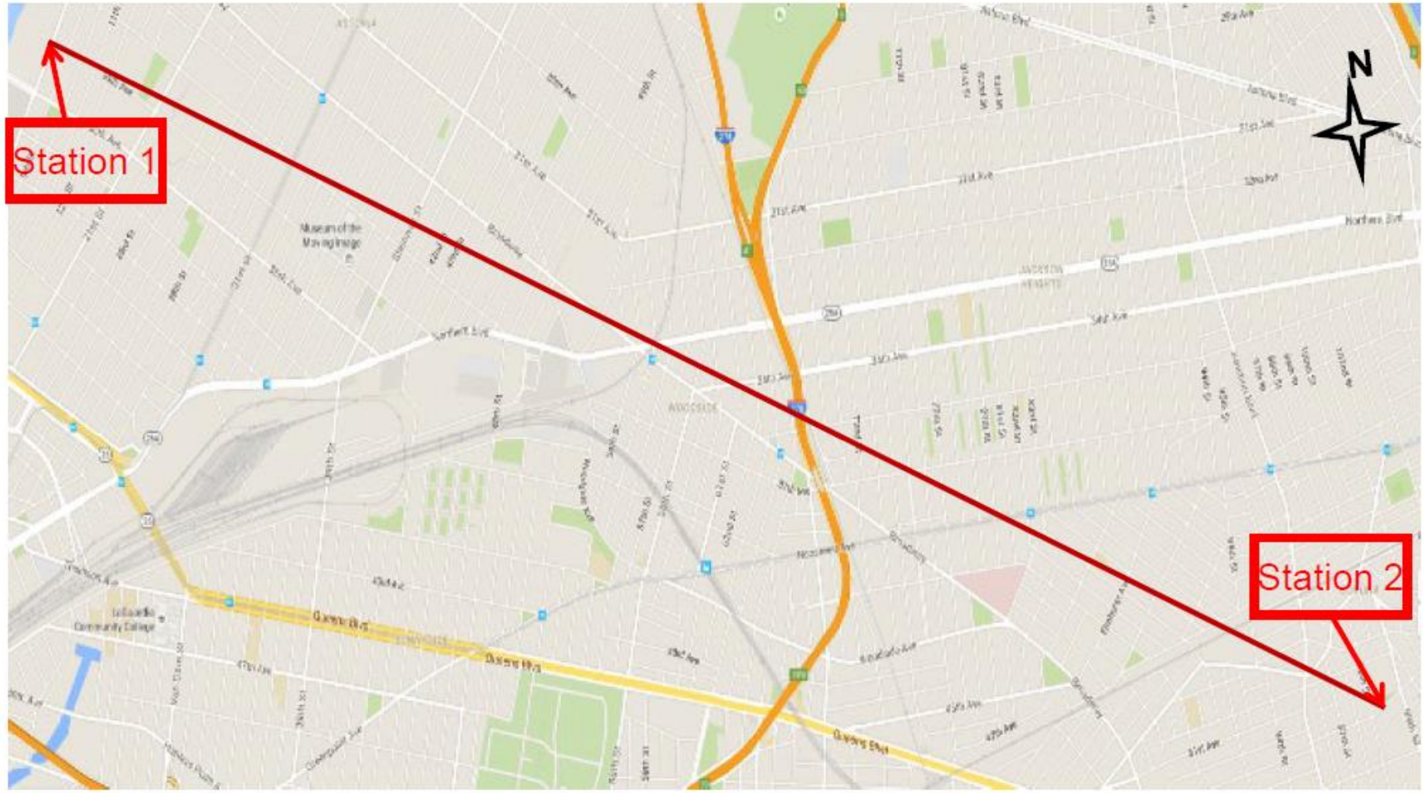
- **125 Pumping Plants**
- **76 Cooling Plants**

Current Challenges	Implementing Solutions
• Dielectric fluid leaks	• Maintaining reliable cathodic protection system • Use of Leak Detection Systems (LDS) • Proactive steel pipe re-coating and installation of carbon wrap
• Condition assessment of mature cable systems	• Dielectric fluid periodic testing - Dissolve Gas Analysis (DGA) • Use of digital x-ray for joint condition assessment • Cable remaining life testing - Degree of Polymerization

Future Challenges	Implementing Solutions
• No longer installing new HPFF feeders since 2010 – Transition to SD feeders – Composite dry terminations – Enough spare of HPFF feeders	• Developed HPFF/SD transition joints • Start implementing dry-type terminations • Working with HPFF cable supplier
• Condition assessment and dynamic rating of SD cable systems	• Implementation of AI – Various sensors and data acquisition systems installation

Case Study – Installation of New 138kV SD Feeder

- 5.7 miles of 138 kV UG Solid Dielectric cable (300 MVA)
  - 6 x 138kV Terminations
  - 17 x 138kV Joints
- 3 Railroad Crossings
- Major Highways Crossings
- Elevated Subway and Bridges



Evaluation Criteria

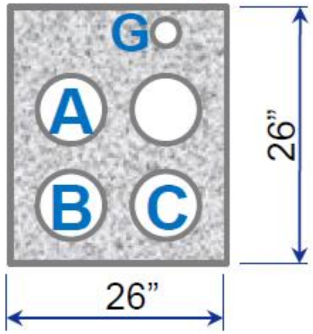
- Constructability
- Project Cost
- Schedule
- Existing Utilities Impact
- Permits
- Land Use Impacts and Easements
- Surface Disruption Impacts in Publicly Sensitive Areas
- Traffic Impact

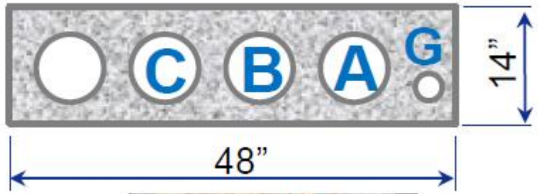
Field Data Analysis

- Traffic study (public bus routes, traffic congested areas, religious institution and school locations along the route)
- Constructability – space and working hours
- Extensive subsurface facilities investigation including test pits and GPR
- Native soil thermal property analysis
- 120 field test pits
- Opportunity to shorten route using easements
- Induced voltage and EMF study

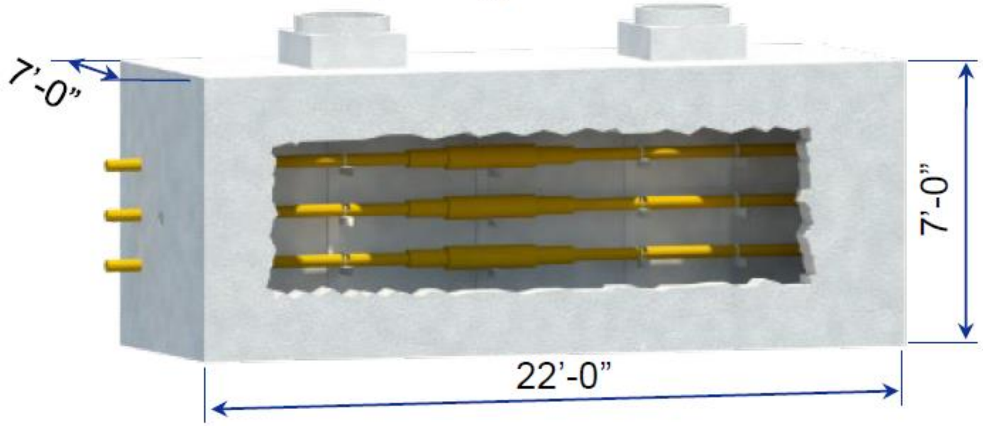
Installation

Single-Circuit Duct Bank



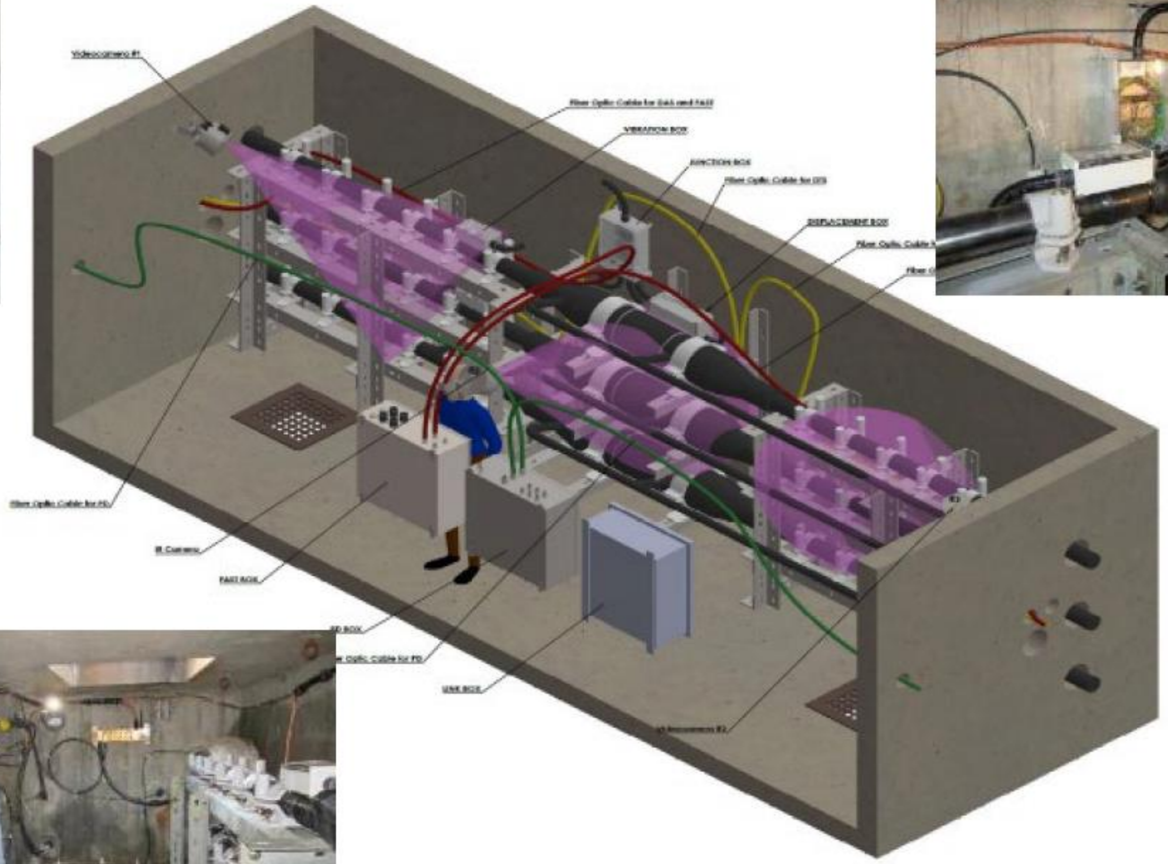


Splicing Vault



AI Sensors and Data Acquisition System Installation

- PD monitoring
- DTS monitoring
- DAS monitoring
  - Fault locating
  - Construction activity
- Video/IR vault inspection
- Local vibration monitoring
- Vault entrance alarm



System Resiliency

- Spare Parts Inventory
  - Strategy for type and quantity of various spare parts
  - Monitoring inventory of replacement parts
  - Proper tools for cable installation and splicing

- Complete Resilient Systems for Operational and Catastrophic Emergencies
  - Flexibility and compatibility with all existing systems
  - Trained and available personnel

THANK YOU.

Michael Jarro

VP of Distribution Operations

Florida Power and Light

Jerry Cook

Senior Director, Project Development

Florida Power and Light

FPL

How FPL undergrounds power lines

An overview of FPL's Storm Secure Underground Pilot Program




Michael Jarro, Vice President - Distribution Operations
Jerry Cook, Sr. Director - Central Maintenance and Construction
March 22, 2022

Hurricane Irma outages caused by wind-blown vegetation led FPL to launch the Storm Secure Underground Pilot Program

Storm Secure Underground Pilot Program

- **Work plan approved by Florida Public Service Commission as part of FPL's Storm Protection Plan**
  - Florida Legislature requires utilities to submit 10-year plans detailing steps, such as hardening and undergrounding, to reduce storm restoration costs and outage times
- **Data-based neighborhood selection criteria**
  - Past hurricane outage performance
  - Vegetation-related outage performance
  - Historical reliability issues
- **Improved resiliency and reliability**
  - Underground lines performed 85% better than overhead during Irma
  - Underground lines 50+% more reliable on day-to-day basis
- **FPL doesn't underground other utilities' lines but notifies them of plans**
- **Paid for by all customers after Public Service Commission approval**

Commonly used equipment

Horizontal or directional boring equipment

Cable reel

Commonly used equipment

Pad-mounted transformer

Handhole

Successes

- **Outreach**
  - Placing cable in rights of way eliminates need to get easements from every customer; speeds execution time of customer outreach
  - Community/HOA meetings with customers, officials improve “buy-in,” result in fewer surprises during construction
  - Augmented Reality tool allows customers to see size and location of assets to be installed – results in getting the “yes” immediately in the field
- **Construction**
  - Meter junction box with flex conduit eliminates need to open meter can
    - Saves customer permit and electrician fees
    - Enables faster construction
  - Designing at feeder level versus individual neighborhood power line or lateral creates productivity efficiencies
    - Allows construction crews to work in a few locations year-round
    - Less windshield time to job; centralized set-ups

Challenges

- Bore equipment availability hampered due to extended market lead times
- Skilled labor availability shortage due to demand from telecoms and other utilities
- Skilled labor wage increases also impact amount of construction that can be executed annually
- Coordination on electrical clearances within and among other FPL construction groups
- Permitting agency backlog impacting construction
  - Agencies not staffing for utility construction growth
- Attachments from telecommunication companies not being removed to facilitate pole removal
  - Telecom utility “attachers” are not incentivized to remove or transfer assets
- Avoiding “dig-ins” using Ground Penetrating Radar, locates, hand digging effective; but looking for more effective tools

Jamie Martin

Vice President of Undergrounding

PG&E

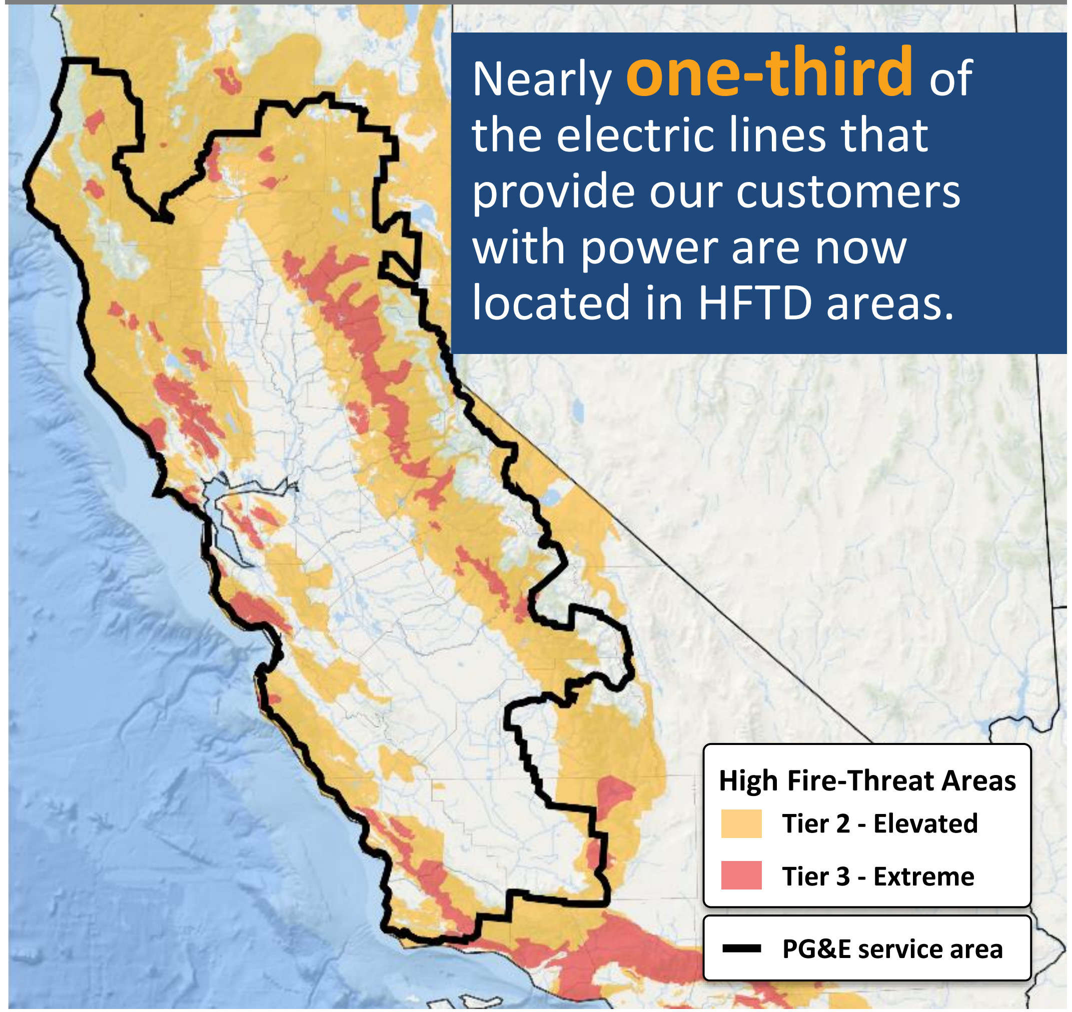
U.S. DEPARTMENT OF ENERGY | OFFICE OF ELECTRICITY

PG&E 10K Underground Program

Jamie Martin
Vice President, Undergrounding

PG&E has Committed to Underground 10,000 Miles of its Electric System

CPUC High Fire-Threat District (HFTD) Map



Source: California Public Utilities Commission

PG&E has taken a stand that catastrophic wildfires shall stop.

- Last year PG&E announced a major new initiative to **underground 10,000 miles of power lines** in high fire risk areas.
- 10,000 miles is nearly **half of the number of miles PG&E has in high-fire threat areas.**
- **This commitment represents the largest effort in the U.S.** to underground power lines as a wildfire risk reduction measure.

Some of the measures included in this presentation are contemplated as additional precautionary measures intended to further reduce the risk of wildfires.

Drought-Intensified Wildfire Risk

Drought conditions are intensifying the risk of wildfire throughout PG&E's service area.

2021

83%
of Calif. was in
extreme drought

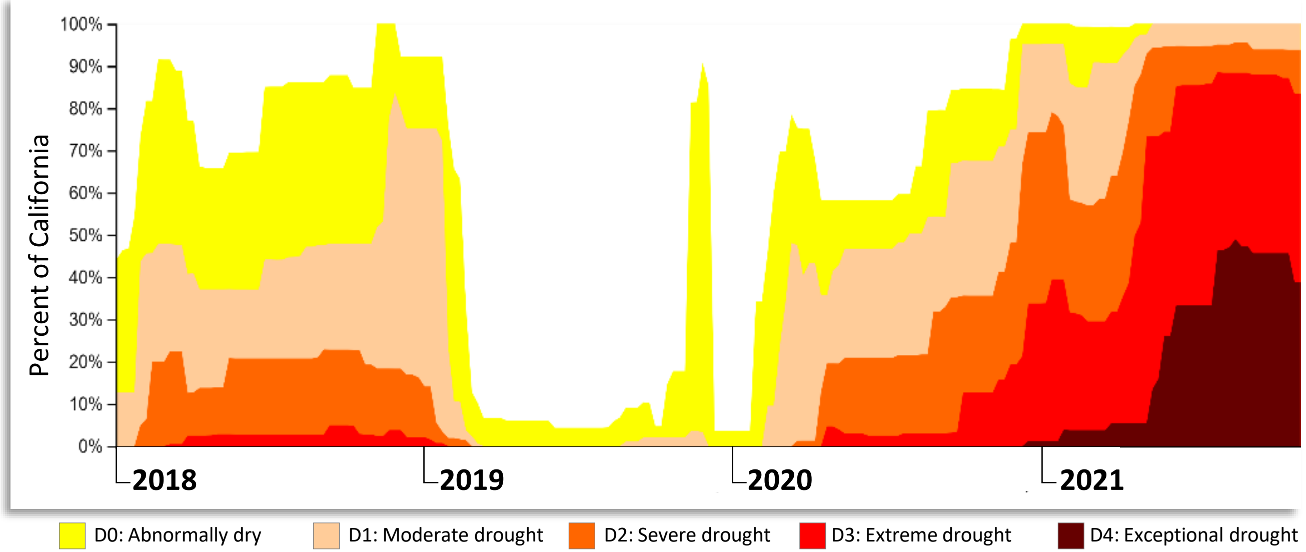
39%
of Calif. was in
exceptional drought

95%
of acreage burned by wildfires ignited on non-RFW* days (47% in 2020)

2022

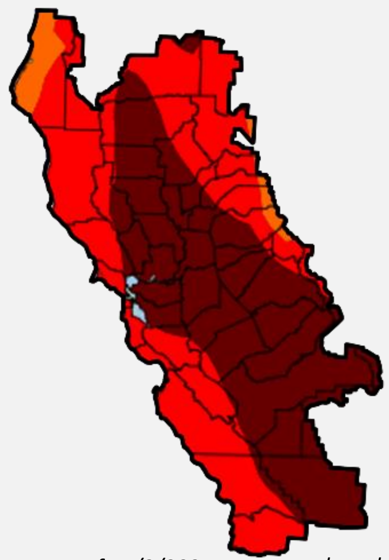
2nd
driest January over the past 128 years

Increase in Drought Conditions in California 2018-2021



Data as of 11/2/2021

2021 California Drought Map



The majority of PG&E's service area was in extreme or exceptional drought throughout much of 2021

- D0: Abnormally dry
- D1: Moderate drought
- D2: Severe drought
- D3: Extreme drought
- D4: Exceptional drought

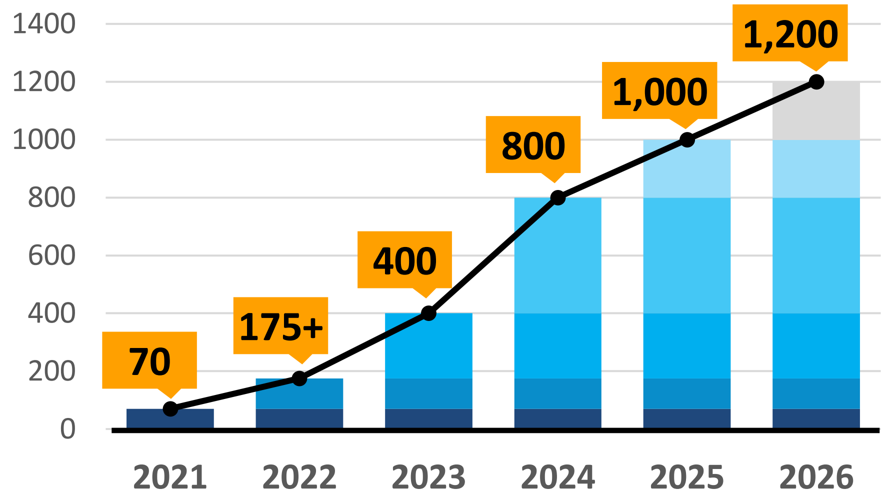
Map as of 11/2/2021 *drought.gov*

* Red Flag Warning

Program Ramp Up and Cost Assumptions

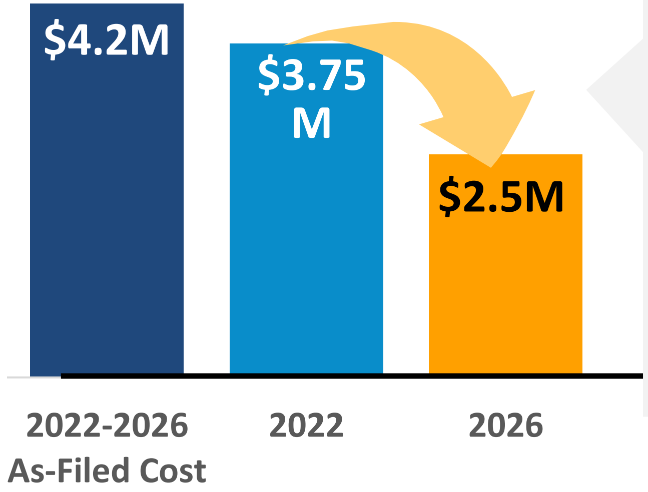
PG&E is undertaking a major new initiative to underground approximately 10,000 miles of power lines in high fire risk areas.

Approximate Target Miles Per Year



Approximate Cost Per Mile

(Unescalated $)



- **Optimize** design and construction standards
- **Bundle** work strategically
- **Deploy** new technology and equipment

This commitment represents the largest effort in the U.S. to underground power lines as a wildfire risk mitigation measure.

Safe	Dependable	Sustainable
99% Risk Reduction & Long Term Resiliency	Reduces PSPS, EPSS and EVM Improves Reliability	Saves Trees

Underground Cost Efficiency Strategies

Through past projects, rebuild efforts and partnerships with industry leaders, we've learned valuable lessons and best practices to help us realize cost efficiencies including:

- **New standards for design and construction** of underground lines that: (1) optimize the type of materials and equipment used and construction methodologies deployed, and (2) reflect the local environment (i.e. - urban vs. rural)

- **Strategically packaging work**, including longer sections of circuits, to take advantage of **economies of scale** in construction

- **Reduce the cycle time** from initial scoping to completion of construction to create efficiencies and expedite execution

- **Deploy new and innovative tools, equipment and technologies** to safely increase production rates and reduce costs

Some of the measures included in this presentation are contemplated as additional precautionary measures intended to further reduce the risk of wildfires.

Undergrounding Areas of Focus

Select Areas of Focus

1	**Community Impacts**	• Construction impacts (i.e., traffic management and outages) • Communicating customer rate impacts as economic
2	**Resources and Materials**	• Resources: Engineering, Design and Construction • Materials and Equipment: Raw material shortages, manufacturer labor shortages and capacity constraints
3	**Joint Trench**	• Incenting joint trenching efforts across broadband, communications, transportation, municipalities and others
4	**Land Rights, Environmental**	• Addressing easement and land rights • Complex environmental and/or heritage considerations
5	**Standards**	• Rapidly updating construction, design and engineering standards

Some of the measures included in this presentation are contemplated as additional precautionary measures intended to further reduce the risk of wildfires.

Clay Koplin

Chief Executive Officer

Cordova Electric

U.S. DEPARTMENT OF ENERGY | OFFICE OF ELECTRICITY

Resilient Power Grids: Strategically Undergrounding Powerlines 3/22/22

Lessons Learned from Kodiak Electric Association and Cordova Electric Cooperative

Cordova: A Case Study

- 100% Conversion from Overhead to Underground on a remote microgrid in a challenging climate and logistics. Set 100% policy in 1978 upon becoming a cooperative to improve reliability; converted from approximately 25% URD in 1978 to 100% URD on September 11, 2011. No storm-related outages in over 10 years, and other benefits.

Challenges:

- Expensive to Install
- Expensive to Repair
- Nothing is Bullet-Proof

Technologies Needed:

- Soft technologies – Permitting, cost-sharing
- Most hard technologies have been resolved:
  - Frost
  - Locating
  - Cost-Effectiveness
  - “Smart” installation

Cost-Effective Approaches

(no silver bullet – value engineering mindset)

- **Proper Handling!**
  - **Wire Delivery and Stocking**
  - **Installation – pulling/terminating**
  - **Defensive Installations**
- **Shared Trench**
- **Custom Design - Engineering**
  - **Proper methods**
  - **Proper materials**
- **Strategic Installation**
  - **Highway Projects**
  - **Piggy-backing**
- **Locating and Repair**
  - **New school, old school, ultra-care in repairs**

Proper Handling

- Wire Chain of custody – handle little & well
- Learn your pulls and use best practices
  - Pull planning software, lube, strain, slack, frost
- Terminations
  - Connectors, hygiene, applications, handling
- Cabinets
  - Location, specs, flexible, maintainable, protected

Shared Trench

- Shared Trench = Shared Cost
- 90% of cost; trenching
- Standard Agreements
- Water, Sewer, Phone, Fiber
- Joint Planning
- Shared Labor
- Shared Permits
- Shared Conduits

Engineering

- Is Conduit Better?
- Conduit Mythbusters:
  - Pull out wire
  - Future use
  - Better protected
  - Frost/Ice
  - Cost-effective
  - Boring
- Direct Bury & Conduit?
- Armored vs. Hardened
- Materials
  - Conduit
  - Wire & hardening
  - Bedding
  - Special (vert/hor)

Highways & Byways

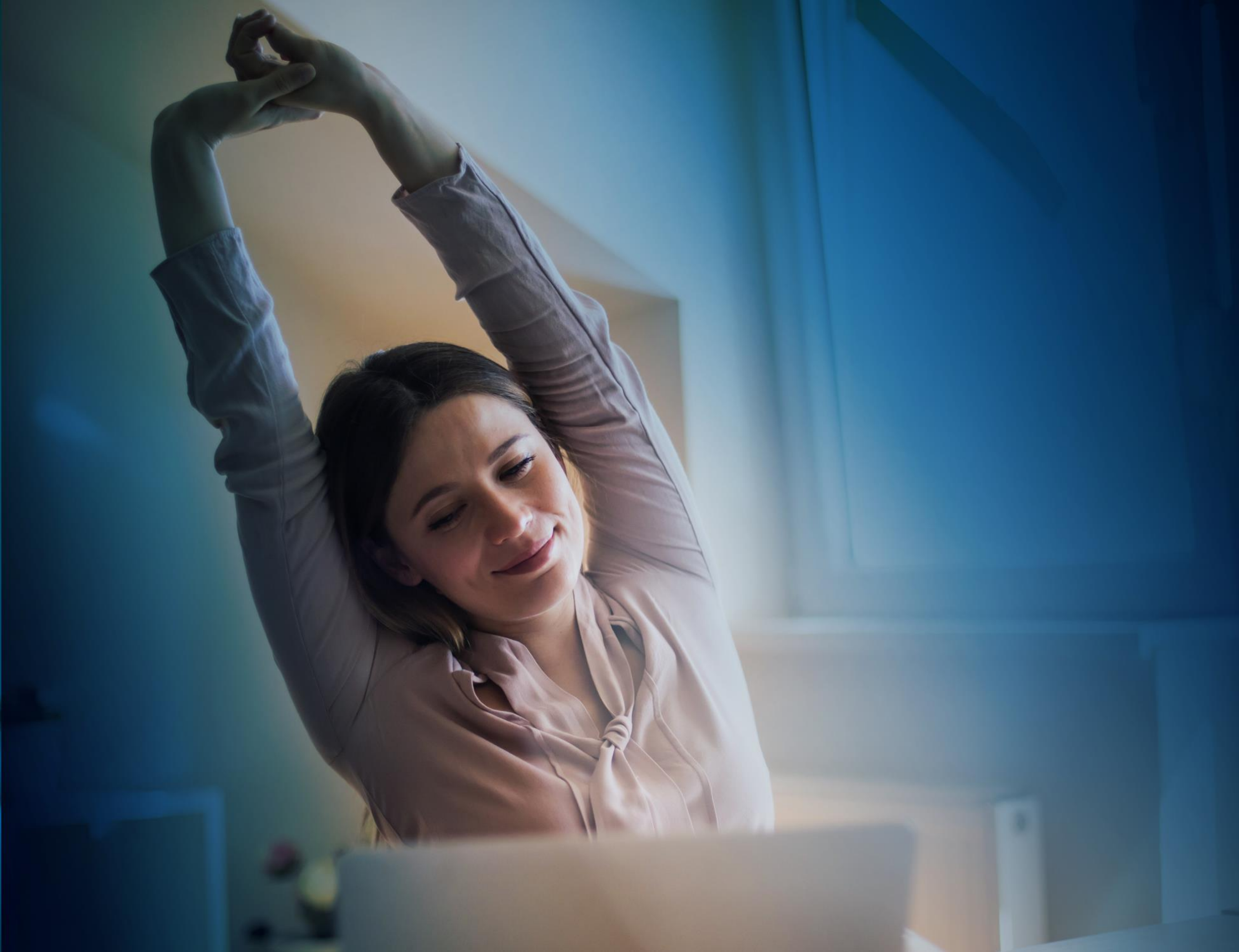
- URDs Best Friend
  - Protection
  - Corridor
  - Partnership
  - Synergy
  - Cost-sharing
  - 7PS
  - Overhead ROW
  - Futuregrid: Mesh
  - Submarine
  - Boring

URD Repair

- Fault Locators
- Forensics
- Locating Faults
  - Next Gen TDR
- Old School
  - TDR
  - Oscilloscope
  - Voltage Divider
  - Thumping
- Power Factor

Questions?

Questions?



Break

We will resume
at 3:15 p.m. ET

From the Regulator's Perspective

U.S. DEPARTMENT OF ENERGY | OFFICE OF ELECTRICITY

Joseph Paladino

Acting Director, Grid Technical Assistance

Office of Electricity

Tom Ballinger

Director, Division of Engineering

Florida Public Service Commission

The Florida Public Service Commission's Multi-faceted Approach to Storm Hardening

A Presentation for the

Department of Energy, Office of Electricity

Tom Ballinger
Director, Division of Engineering
Florida Public Service Commission

March 22, 2022

Overview

- Background
- Florida Public Service Commission (FPSC) Actions
- 2017-18 FPSC Hurricane Review
- Targeted Underground Projects
- Recent Legislation

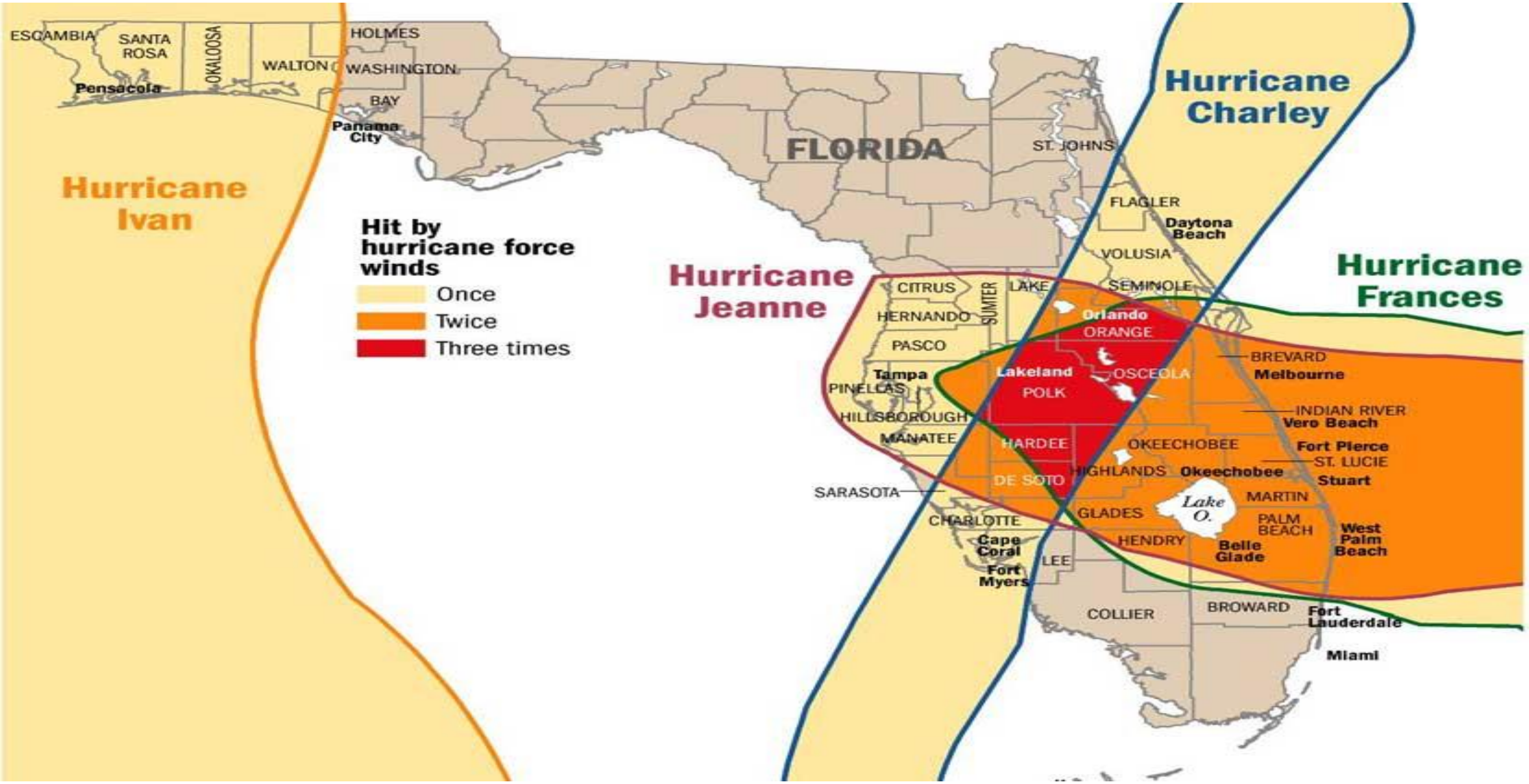
Background

- Reliable electric service is the cornerstone of Florida's economy.

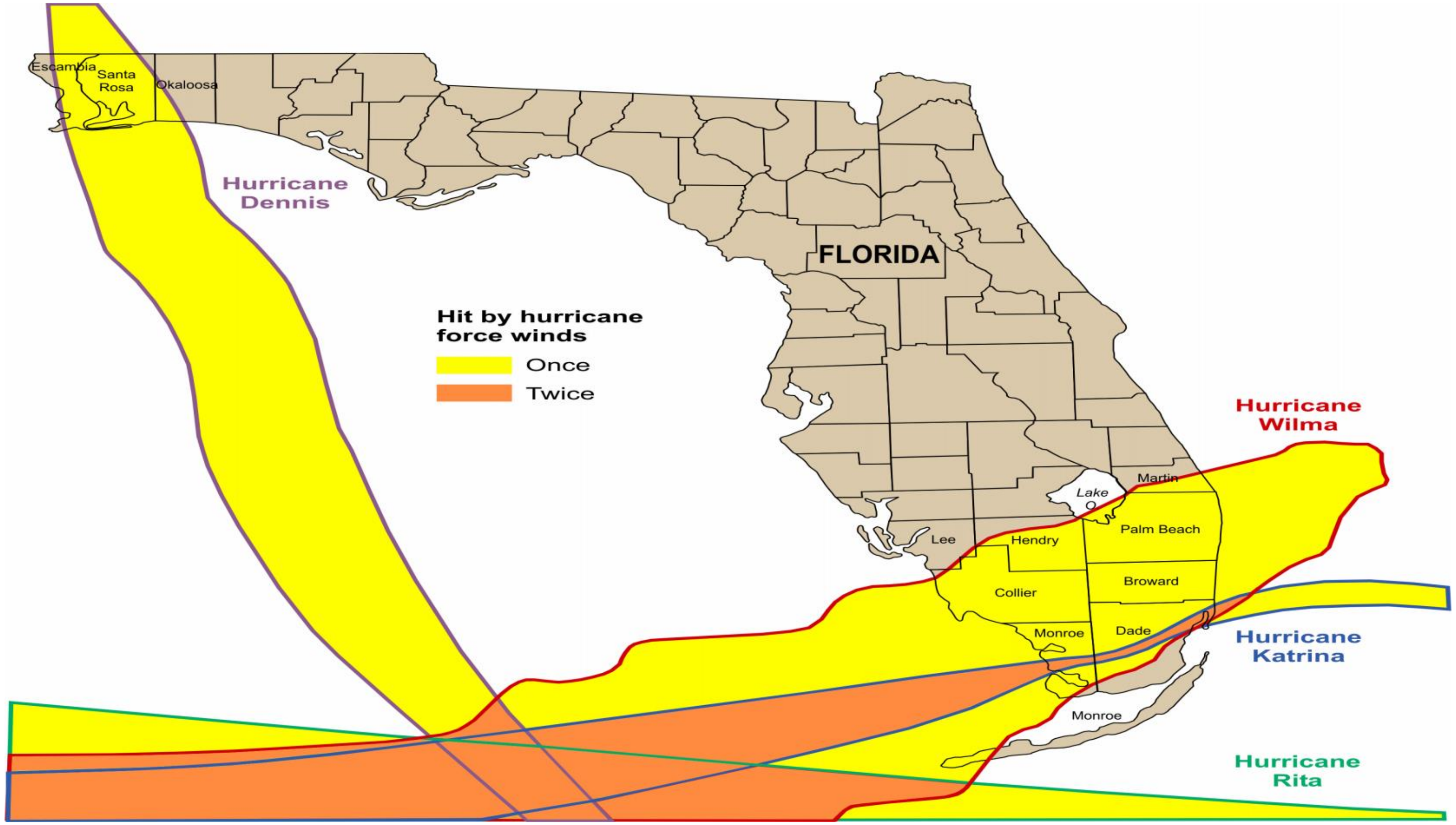
- The Legislature has charged the FPSC with ensuring the provision of adequate electricity at a reasonable cost.

- Damages from the 2004 & 2005 hurricanes resulted in a strong public outcry to strengthen electric utility infrastructure.

2004 Hurricane Paths



2005 Hurricane Paths



FPSC Actions

- In July 2007, the FPSC filed a report with the Legislature detailing its approach to storm hardening.
  - ✓ Goal of storm hardening is to balance the desire to minimize storm damage, reduce outages and restoration time while mitigating excessive rate increases to customers.
  - ✓ Floridians should maintain a high level of storm preparedness.
  - ✓ Strengthening Florida’s electric infrastructure should include a wide range of activities that will take years to complete.

http://www.floridapsc.com/Files/PDF/Publications/Reports/Electricgas/stormhardening2007.pdf

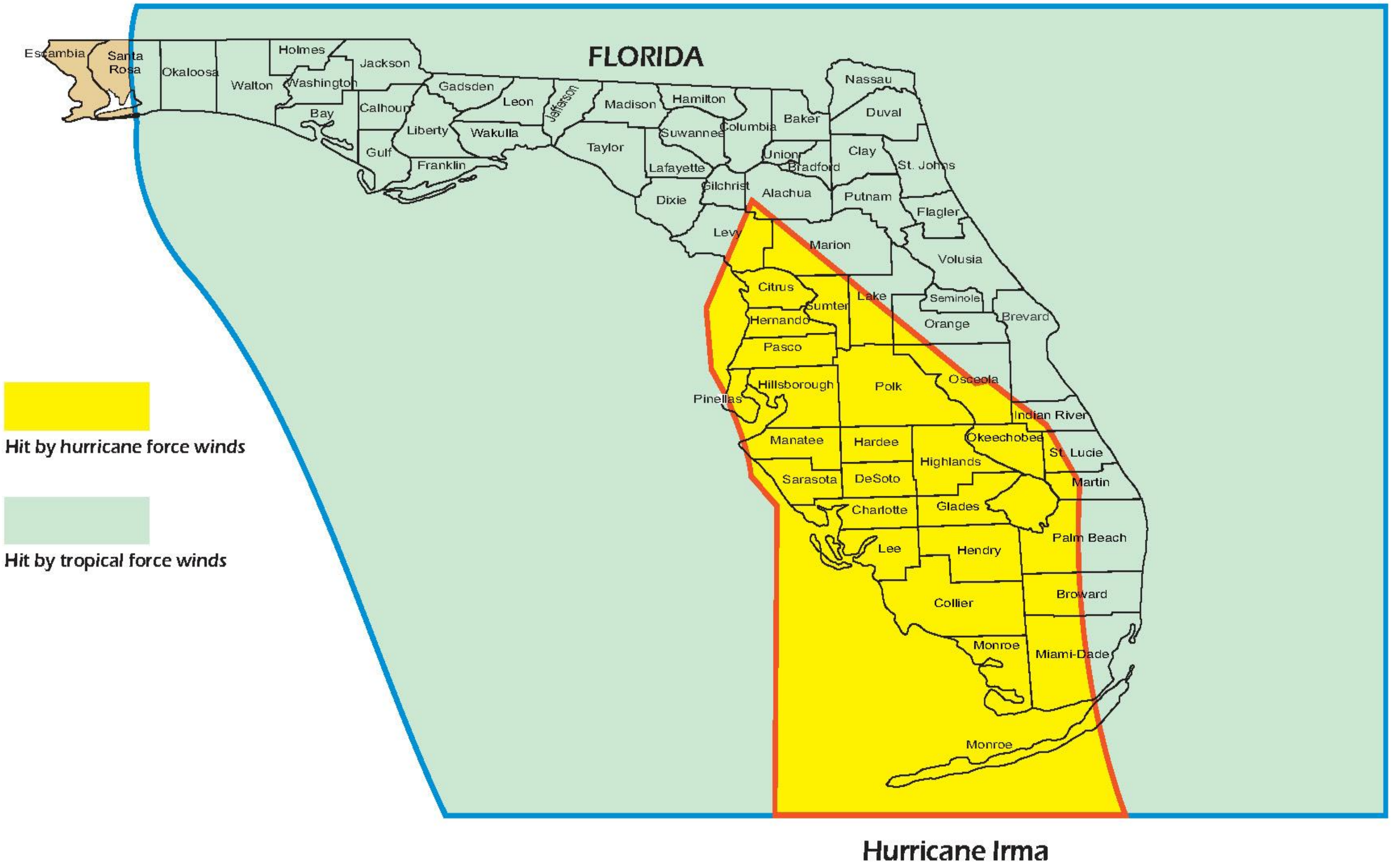
FPSC's Actions

- Annual hurricane preparedness briefings.
- Formal pole inspection and reporting.
- Additional distribution reliability reporting for IOUs, Munis, and Coops.

FPSC’s Actions

- Ten storm preparedness initiatives, including:
  - ✓ Enhanced vegetation management.
  - ✓ Forensic data collection.
  - ✓ Collaborative research.
  - ✓ Increased coordination with local governments.

2017 Hurricane Irma's Path



Hurricane Irma

- 6.7 million customers, approximately 64% of the State, lost power.

- Electric outages across all 67 counties.

- 10 Counties had more than 90% of their customers affected. (Baker, Bradford, Collier, Columbia, Hardee, Highlands, Lafayette, Nassau, Okeechobee, and Suwanee)

- Over 20,000 mutual aid personnel, in addition to Florida's utility workers, activated from multiple states and Canada.

2017-18 FPSC Hurricane Review

- Despite the goal of reducing outages, even storm hardened facilities can suffer damage due to events beyond a utility's control.

2017-18 FPSC Hurricane Review

- On October 3, 2017, the FPSC opened Docket No. 20170215-EU to review electric utility storm preparedness and restoration actions associated with recent hurricanes.

- The objective was to identify potential damage mitigation options and restoration improvements. The FPSC also critically evaluated its rules and processes for potential improvements.

2017-18 FPSC Hurricane Review

- The FPSC's findings included:
  - ✓ Florida's aggressive storm hardening programs are working.
  - ✓ The primary causes of power outages came from outside the utilities' rights of way including falling trees, displaced vegetation, and other debris.
  - ✓ The length of outages was reduced markedly from the 2004-2005 storm season.
  - ✓ Hardened overhead distribution facilities performed better than non-hardened facilities.

FLORIDA PUBLIC SERVICE COMMISSION
STATE OF FLORIDA

2017-18 FPSC Hurricane Review

➢ FPSC's findings continued:

- ✓ Very few transmission structure failures were reported.
- ✓ Underground facilities performed much better compared to overhead facilities.
- ✓ Rising customer expectations are that resilience and restoration will have to continually improve.

http://www.floridapsc.com/Files/PDF/Publications/Reports/Electricgas/UtilityHurricanePreparednessRestorationActions2018.pdf

FLORIDA PUBLIC SERVICE COMMISSION
STATE OF FLORIDA

Targeted Underground Conversions

- In 2018, Duke Energy Florida (DEF) and Florida Power & Light (FPL) initiated pilot programs for targeted underground lateral conversions.

- Projects prioritized based on historic performance.

- Some projects delayed or cancelled due to inability to obtain easements.

Targeted Underground Conversions

Targeted Underground Projects				
	2018	2019	2020	2021
DEF	12 ($3.7 m)	3 ($17.7 m)	205 ($29.4 m)	204 ($65.2 m)
FPL	0	33 ($76 m)	216 ($129 m)	350 ($212.5 m)
Gulf	0	0	0	8 ($5.2 m)
TECO	0	0	1 ($8 m)	520 ($79.5 m)

Recent Legislation

- In 2019, the Florida Legislature passed Senate Bill 796 to enact Section 366.96, Florida Statutes (F.S.), entitled “Storm Protection Plan Cost Recovery.”

- Each IOU files a transmission and distribution storm protection plan (SPP) that covers the immediate 10-year planning period with updates every three years.

Recent Legislation

- Pursuant to Section 366.96(7), F.S., the Commission shall conduct an annual proceeding to determine the utility's prudently incurred SPP costs.

- Annual status reports to Governor and Legislature.

http://www.psc.state.fl.us/ElectricNaturalGas/StormProtectionPlans

Questions?

Tom Ballinger

Director, Division of Engineering

Florida Public Service Commission

tballing@psc.state.fl.us

850/413-6680

Joey Chen

Senior Advisor to the Chairman

Maryland Public Service Commission

Undergrounding Electric Powerlines in Maryland

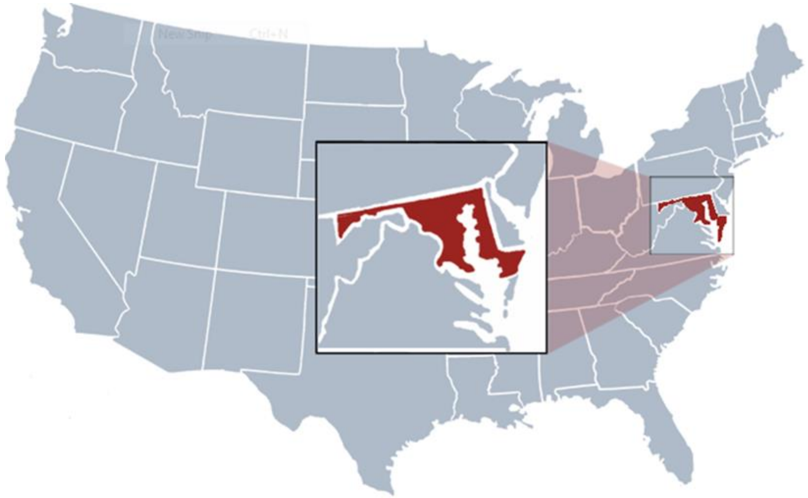
Joey Chen
Advisor to the Chairman
Maryland Public Service Commission

Disclaimer

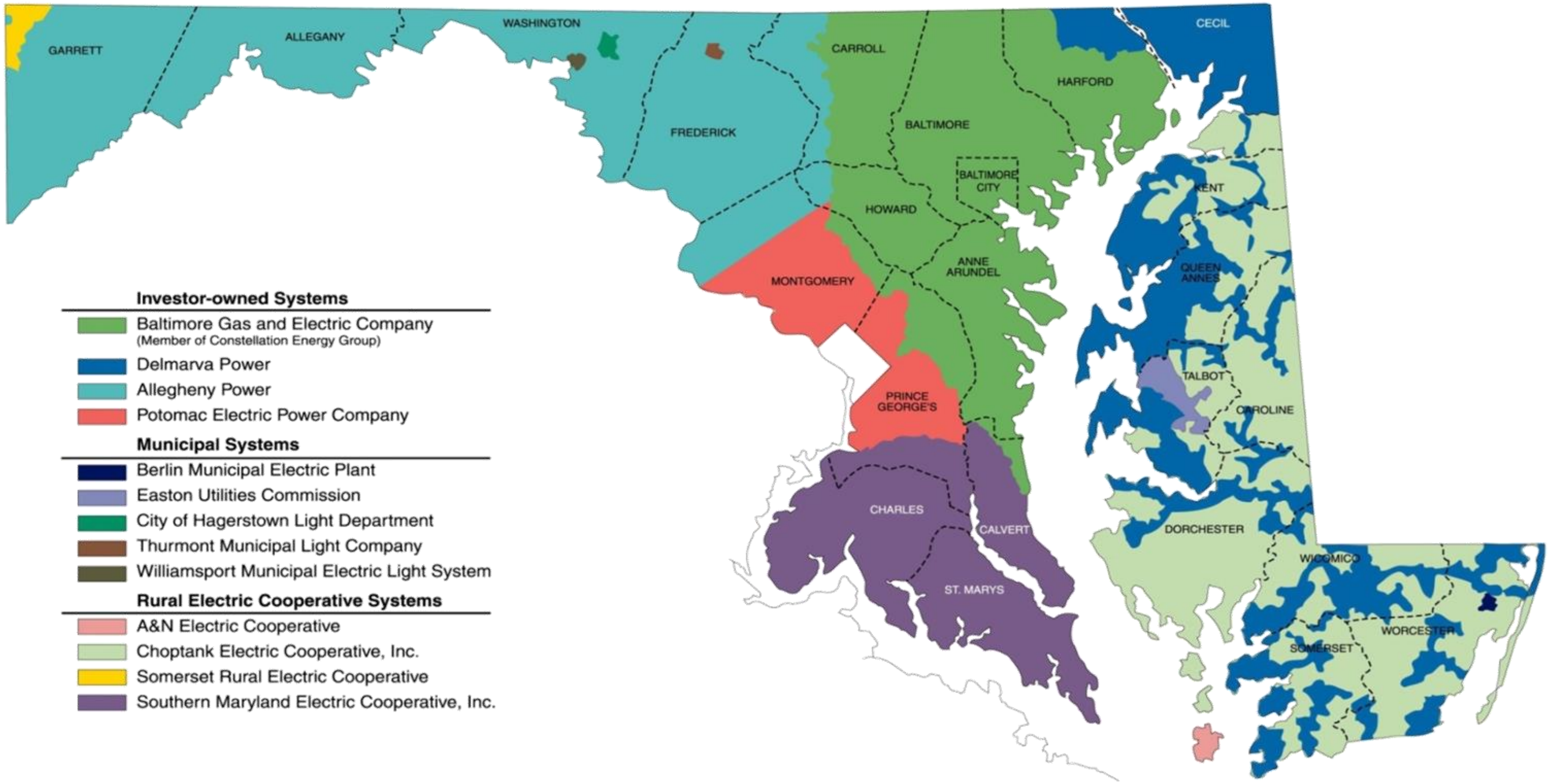
Any ideas or opinions shared are the views of the presenter and do not reflect the position of the Maryland PSC or its Commissioners.

State of Maryland

- Public Service Commission Jurisdiction
  - Electric and natural gas utility services and ratemaking
  - Competitive retail supplier licensing
  - Transmission and generation certification
- Guiding Principles
  - Public safety
  - Reliable and Affordable
  - Customer-centered
  - Non-discriminatory
  - Environmentally sustainable



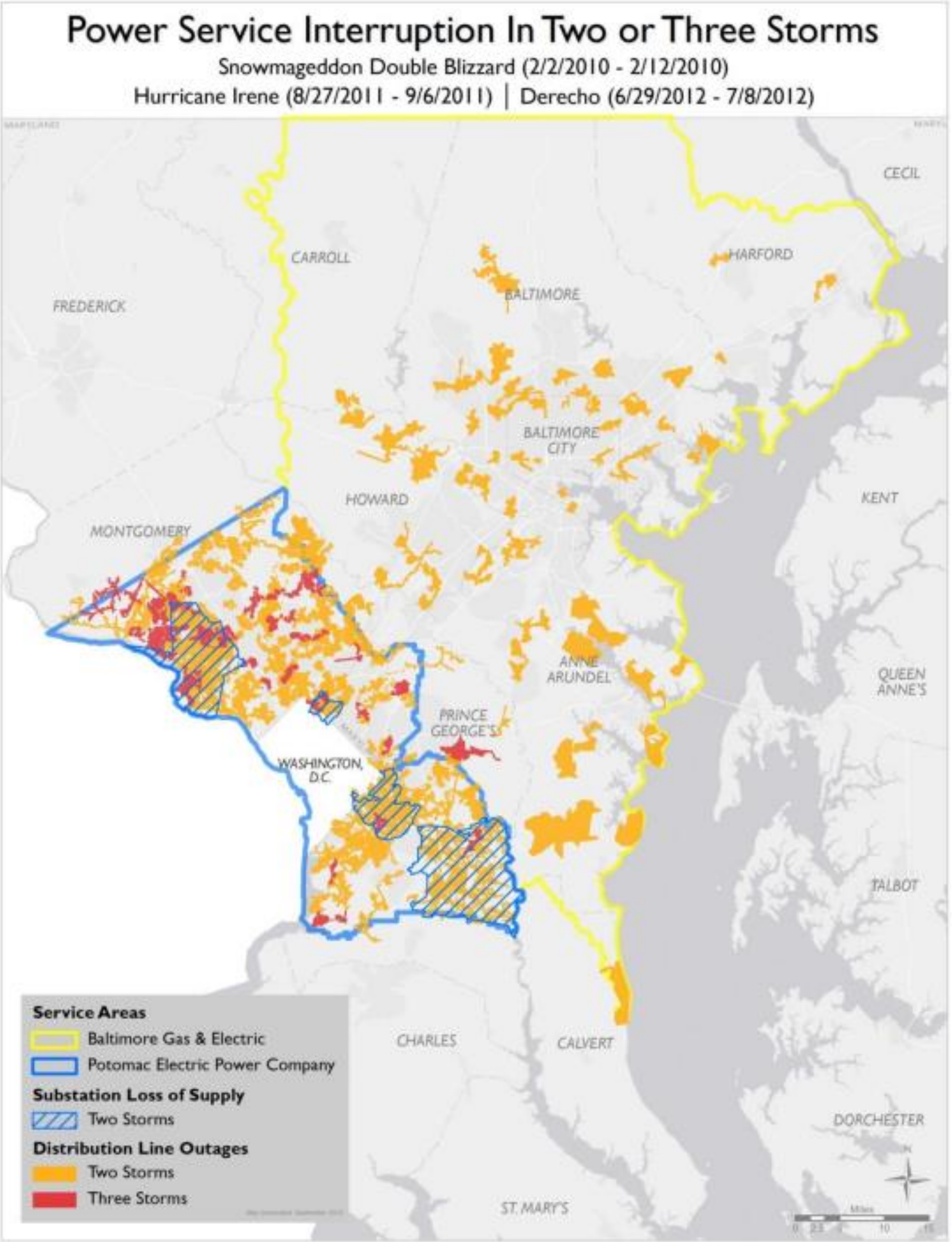
Maryland Electric Utilities



Undergrounding in Maryland

- COMAR 20.85.01 & 20.85.03
  - New Residential and Non-Residential Customers
- 1999 Extreme Weather Outages
  - Investigation into Utility Preparedness
- 2012 Derecho Storm
  - Grid Resiliency Task Force Report
  - Utility Major Outage Reporting
- Selective Undergrounding
- Non-Undergrounding Alternatives

Source: PHI



Source: 2012 Grid Resiliency Task Force Report

Undergrounding in Maryland

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- Non-Undergrounding Alternatives

Source: PHI

Thank You!

Joey Chen
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MARYLAND
Public Service Commission

Questions?

Michael Pesin

Deputy Assistant Secretary,
Advanced Grid R&D Division

Office of Electricity

U.S. DEPARTMENT OF ENERGY | OFFICE OF ELECTRICITY

Thank You!

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