Resilient Power Grids: Strategically Undergrounding Powerlines

March 22, 2022

Stay tuned…we will begin at approximately 1:00 PM ET
Resilient Power Grids: Strategically Undergrounding Powerlines

March 22, 2022

1:00 PM - 4:30 PM ET
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.
Patricia Hoffman
Acting Director,
Grid Deployment Office
Peter Larsen
Staff Scientist
Lawrence Berkeley National Lab
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...

- ...increase in % share of T&D lines that are underground has a statistically significant correlation with improved reliability
• 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
## Key Stakeholders

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

**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.)

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.

http://www.icecalculator.com/
Net social loss

Varying all key assumptions simultaneously led to consistent net social losses

Additional lifecycle costs associated with undergrounding dominate cost-benefit results
Sensitivity analysis

- 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)

Note: Results generated by using 10th (90th) percentile value for individual assumption while holding all other assumptions constant at median value.
Possibility of net benefits

- Based on the initial configuration of this model, the Texas public utility commission should not 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?
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
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

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

**Key:**

*Minor impact on results → ***** Major impact on results*
- NPV of undergrounding and status quo costs ($2015)
Estimated benefits

**Customer interruptions**

- Status Quo: 22% underground and 25 outages/year (i.e., no additional undergrounding)
- Undergrounding: 0.141 outage decrease for 1% increase in undergrounded line miles

**Interruption minutes**

- Status Quo: 22% underground and 240 interrupted minutes/year (i.e., no additional undergrounding)
- Undergrounding: 1,000 minute total duration decrease for 1% increase in undergrounded line miles
- Actual: CEC-reported distribution system outage duration
**Net social benefit**

<table>
<thead>
<tr>
<th>Impact Category</th>
<th>100% Underground</th>
<th>Status Quo</th>
<th>Net Cost ($millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Health &amp; safety costs</td>
<td>$0.2</td>
<td>$0</td>
<td>$0.2</td>
</tr>
<tr>
<td>Lifecycle costs</td>
<td>$35.3</td>
<td>$31.1</td>
<td>$4.1</td>
</tr>
<tr>
<td>Total net costs (Undergrounding)</td>
<td></td>
<td></td>
<td>$4.3</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Impact Category</th>
<th>100% Underground</th>
<th>Status Quo</th>
<th>Net Avoided Costs ($millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Interruption costs</td>
<td>$130.1</td>
<td>$194.7</td>
<td>$64.6</td>
</tr>
<tr>
<td>Aesthetic costs</td>
<td>$27.9</td>
<td>$24.4</td>
<td>$3.5</td>
</tr>
<tr>
<td>Enviro. restoration costs</td>
<td>$2.4</td>
<td>$3.1</td>
<td>$0.6</td>
</tr>
<tr>
<td>Total net benefits (Undergrounding)</td>
<td></td>
<td></td>
<td>$68.7</td>
</tr>
</tbody>
</table>

**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.
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.
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

Peter Larsen
Email: PHLarsen@lbl.gov
Phone: (510) 486-5015
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

<table>
<thead>
<tr>
<th>#</th>
<th>Sensitivity/ scenario analysis</th>
<th>Range</th>
<th>Impact Category</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Minimum value (10th %)</td>
<td>Base case value (50th %)</td>
<td>Maximum value (90th %)</td>
</tr>
<tr>
<td>1</td>
<td>Alternative replacement cost of undergrounding T&amp;D lines ($ per mile)</td>
<td>$71,400 (dist.) $336,000 (trans.)</td>
<td>$357,000 (dist.) $1,680,000 (trans.)</td>
</tr>
<tr>
<td>2</td>
<td>Alternative values of lost load for each customer class ($ per event)</td>
<td>$0.5 (residential) $87 (other) $1,843.4 (C&amp;I)</td>
<td>$2.7 (residential) $435 (other) $9,217 (C&amp;I)</td>
</tr>
<tr>
<td>3</td>
<td>Alternative discount rates (%)</td>
<td>2%</td>
<td>10%</td>
</tr>
<tr>
<td>4</td>
<td>Alternative aesthetic-related property loss factors (% of property value)</td>
<td>2.5%</td>
<td>12.5%</td>
</tr>
<tr>
<td>5</td>
<td>Alternative incidence rates for accidents and fatalities (per 100,000 employees)</td>
<td>420 (non-fatal) 3 (fatal)</td>
<td>2,100 (non-fatal) 15 (fatal)</td>
</tr>
<tr>
<td>6</td>
<td>Alternative accident costs and VSL ($ per accident/$ per life)</td>
<td>$26,131.6 $1,380,000 (VSL)</td>
<td>$130,658 $6,900,000 (VSL)</td>
</tr>
<tr>
<td>7</td>
<td>Alternative conservation easement prices ($/acre)</td>
<td>$600</td>
<td>$3,000</td>
</tr>
<tr>
<td>8</td>
<td>Alternative lifespan assumptions for overhead T&amp;D infrastructure (years)</td>
<td>45</td>
<td>60</td>
</tr>
<tr>
<td>9</td>
<td>Share of underground line miles impact on reliability</td>
<td>-0.0002</td>
<td>-0.001</td>
</tr>
<tr>
<td>10</td>
<td>Number of customers per line mile</td>
<td>15</td>
<td>75.0</td>
</tr>
<tr>
<td>11</td>
<td>Annual O&amp;M cost expressed as % of replacement cost: underground T&amp;D lines</td>
<td>1% (trans.) 0.1% (dist.)</td>
<td>5% (trans.) 0.5% (dist.)</td>
</tr>
</tbody>
</table>
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.

<table>
<thead>
<tr>
<th>#</th>
<th>Sensitivity/ scenario analysis</th>
<th>Range</th>
<th>Impact Category</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>Minimum value (10th %)</td>
</tr>
<tr>
<td>1</td>
<td>1978 replacement cost of undergrounding dist. lines ($2015 per mile)</td>
<td>$60,814</td>
<td>$304,070</td>
</tr>
<tr>
<td>2</td>
<td>Alternative values of lost load for each customer class ($ per event)</td>
<td>-80% below base case values</td>
<td>See Figures 40–42</td>
</tr>
<tr>
<td>3</td>
<td>Alternative aesthetic-related property loss factors (% of property value)</td>
<td>2.5%</td>
<td>12.5%</td>
</tr>
<tr>
<td>4</td>
<td>Alternative conservation easement prices ($/acre)</td>
<td>$1,091.2</td>
<td>$5,456</td>
</tr>
<tr>
<td>5</td>
<td>Alternative lifespan assumptions for overhead dist. infrastructure (years)</td>
<td>20</td>
<td>40</td>
</tr>
<tr>
<td>6</td>
<td>Outage duration and frequency change due to undergrounding activities</td>
<td>25 outages/240 minutes (1978); 22.8 outages/224.3 minutes (2015)</td>
<td>25 outages/240 minutes (1978); 14 outages/161.5 minutes (2015)</td>
</tr>
<tr>
<td>7</td>
<td>Workers compensation direct and indirect cost ($/accident)</td>
<td>$32,143.4</td>
<td>$160,717</td>
</tr>
</tbody>
</table>

* Indicates a significant impact or assumption.
Questions?
Break

We will begin at 1:45 p.m. ET
Experiences from the Field
Eric Hsieh
Director, Grid Components and Systems
Office of Electricity
Making a Resilient Power Grid: Strategically Undergrounding Power Lines
DOE Workshop - March 22, 2022

Arie Makovoz – Technical expert
Transmission Line Engineering Department
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
<table>
<thead>
<tr>
<th>Current Challenges</th>
<th>Implementing Solutions</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Dielectric fluid leaks</td>
<td>• Maintaining reliable cathodic protection system</td>
</tr>
<tr>
<td></td>
<td>• Use of Leak Detection Systems (LDS)</td>
</tr>
<tr>
<td>• Condition assessment of mature cable systems</td>
<td>• Proactive steel pipe re-coating and installation of carbon wrap</td>
</tr>
<tr>
<td></td>
<td>• Dielectric fluid periodic testing - Dissolve Gas Analysis (DGA)</td>
</tr>
<tr>
<td></td>
<td>• Use of digital x-ray for joint condition assessment</td>
</tr>
<tr>
<td></td>
<td>• Cable remaining life testing - Degree of Polymerization</td>
</tr>
</tbody>
</table>
### Future Challenges

- No longer installing new HPFF feeders since 2010
  - Transition to SD feeders
  - Composite dry terminations
  - Enough spare of HPFF feeders

- Condition assessment and dynamic rating of SD cable systems

### Implementing Solutions

- Developed HPFF/SD transition joints
- Start implementing dry-type terminations
- Working with HPFF cable supplier

- 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

<table>
<thead>
<tr>
<th>Dimensions</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>26&quot; x 48&quot;</td>
<td>14&quot;</td>
</tr>
<tr>
<td>22'-0&quot;</td>
<td>7'-0&quot;</td>
</tr>
</tbody>
</table>
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
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
PG&E 10K Underground Program

Jamie Martin
Vice President, Undergrounding
PG&E has committed to underground 10,000 miles of its electric system. 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.

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)

2nd driest January over the past 128 years

Increase in Drought Conditions in California 2018-2021

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

Data as of 11/2/2021

* Red Flag Warning

Map as of 11/2/2021 drought.gov
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

<table>
<thead>
<tr>
<th>Year</th>
<th>Approximate Target Miles</th>
</tr>
</thead>
<tbody>
<tr>
<td>2021</td>
<td>70</td>
</tr>
<tr>
<td>2022</td>
<td>175+</td>
</tr>
<tr>
<td>2023</td>
<td>400</td>
</tr>
<tr>
<td>2024</td>
<td>800</td>
</tr>
<tr>
<td>2025</td>
<td>1,000</td>
</tr>
<tr>
<td>2026</td>
<td>1,200</td>
</tr>
</tbody>
</table>

### Approximate Cost Per Mile (Unescalated $)

<table>
<thead>
<tr>
<th>Year</th>
<th>Approximate Cost Per Mile</th>
</tr>
</thead>
<tbody>
<tr>
<td>2022</td>
<td>$3.75M</td>
</tr>
<tr>
<td>2026</td>
<td>$2.5M</td>
</tr>
<tr>
<td>2022-2026</td>
<td>$4.2M</td>
</tr>
</tbody>
</table>

- **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**
- **99% Risk Reduction & Long Term Resiliency**

**Dependable**
- **Reduces** PSPS, EPSS and EVM
- **Improves** Reliability

**Sustainable**
- **Saves** Trees

63
Some of the measures included in this presentation are contemplated as additional precautionary measures intended to further reduce the risk of wildfires.

**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

<table>
<thead>
<tr>
<th>Select Areas of Focus</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Community Impacts</td>
</tr>
<tr>
<td>• Construction impacts (i.e., traffic management and outages)</td>
</tr>
<tr>
<td>• Communicating customer rate impacts as economic</td>
</tr>
<tr>
<td>2. Resources and Materials</td>
</tr>
<tr>
<td>• Resources: Engineering, Design and Construction</td>
</tr>
<tr>
<td>• Materials and Equipment: Raw material shortages, manufacturer labor shortages and capacity constraints</td>
</tr>
<tr>
<td>3. Joint Trench</td>
</tr>
<tr>
<td>• Incenting joint trenching efforts across broadband, communications, transportation, municipalities and others</td>
</tr>
<tr>
<td>4. Land Rights, Environmental</td>
</tr>
<tr>
<td>• Addressing easement and land rights</td>
</tr>
<tr>
<td>• Complex environmental and/or heritage considerations</td>
</tr>
<tr>
<td>5. Standards</td>
</tr>
<tr>
<td>• Rapidly updating construction, design and engineering standards</td>
</tr>
</tbody>
</table>
Clay Koplin
Chief Executive Officer
Cordova Electric
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
The Last Overhead Line De-Energized

Questions?
Questions?
Break

We will resume at 3:15 p.m. ET
From the Regulator’s Perspective
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

Hit by hurricane force winds
- Once
- Twice
- Three times

Hurricane Ivan
Hurricane Jeanne
Hurricane Frances
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.

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

Hit by hurricane force winds

Hit by tropical force winds
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.
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.

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

<table>
<thead>
<tr>
<th></th>
<th>2018</th>
<th>2019</th>
<th>2020</th>
<th>2021</th>
</tr>
</thead>
<tbody>
<tr>
<td>DEF</td>
<td>12 ($3.7 m)</td>
<td>3 ($17.7 m)</td>
<td>205 ($29.4 m)</td>
<td>204 ($65.2 m)</td>
</tr>
<tr>
<td>FPL</td>
<td>0</td>
<td>33 ($76 m)</td>
<td>216 ($129 m)</td>
<td>350 ($212.5 m)</td>
</tr>
<tr>
<td>Gulf</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>8 ($5.2 m)</td>
</tr>
<tr>
<td>TECO</td>
<td>0</td>
<td>0</td>
<td>1 ($8 m)</td>
<td>520 ($79.5 m)</td>
</tr>
</tbody>
</table>
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?

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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: 2012 Grid Resiliency Task Force Report
Undergrounding in Maryland

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• Non-Undergrounding Alternatives

Source: PHI
Thank You!

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Questions?
Michael Pesin
Deputy Assistant Secretary, Advanced Grid R&D Division
Office of Electricity
Thank You!