Together, Building
a Better California

Undergrounding Benchmarking Report

April 12, 2024

Executive Summary

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In recent years, the frequency, intensity, and financial risks of natural disasters have increased.[1] In response, a growing number of utilities have employed undergrounding—burying electric assets under ground—as a system hardening and resilience approach. Some states have even enacted laws to enable strategic undergrounding.[2]

In 2023, Pacific Gas and Electric Company (PG&E) and its consultant conducted a benchmarking study on 11 electric utility strategic undergrounding programs.[3] Strategic undergrounding programs are defined as those in which the utility chooses electric assets to underground with a goal of mitigating safety, reliability, or other risks.[4] The participating utilities represent geographic regions across the United States and have strategic undergrounding programs in various states of development. Collectively, these utilities serve more than 60 million customers.

The purpose of this study was to learn how different utilities across the United States (US) are approaching strategic undergrounding in their service areas and identify trends and lessons learned. Overhead system hardening programs are not addressed in the study. Participating utilities responded to an online survey and participated in follow-up phone interviews. Themes across surveys and interviews touched on: (1) the scale and scope of undergrounding; (2) utilities' motivation to underground and site selection approach; (3) costs and cost containment; (4) customer engagement; and (5) technical standards and operations.

Key takeaways were:

- Scale and scope of undergrounding programs
    - Participating utilities' programs vary in scale, from established programs that have converted more than 1,500 overhead miles to underground to small pilots
    - Most utilities are undergrounding primary distribution lines, secondary distribution lines, and service lines, although some are pursuing alternative strategies.
- Motivation and site selection
    - Utilities in the South and Midwest cited reliability and/or resilience to weather events as their main motivations for strategic undergrounding. Utilities in the West said they aim for their strategic undergrounding programs to reduce wildfire risk.
    - Utilities selected sites based on metrics related to their motivation for pursuing strategic undergrounding: reliability metrics in the South and Midwest, and wildfire risk analysis in the West.
- Cost and cost containment
    - Unit costs are highly variable and are affected by factors such as terrain and population density. On the whole, Southern and Midwestern utilities see lower costs than Western utilities.

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[1] Paci, J., M. Newman, and T. Gage, "The Economic, Fiscal, and Environmental Costs of Wildfires in California," June 27, 2023, p. 1. Available at: https://www.moore.org/docs/default-source/default-document-library/the-economic-fiscal-and-environmental-costs-of-wildfires-in-ca.pdf?sfvrsn=1b1b620c_0
[2] Code of Virginia § 56-585.1(A)(6); Florida Statutes Title XXVII, 366.96; and California Senate Bill 884 all enable cost recovery for strategic undergrounding efforts that meet certain requirements and follow plans approved by relevant regulatory agencies.
[3] The 11 participants include PG&E.
[4] Other undergrounding programs may convert overhead facilities to underground at the request of municipalities or property owners, or for other reasons.

- Several utilities noted negative impacts of a constrained supply of pad mount transformers in the second half of 2023.
- Utilities noted that economies of scale (e.g., contracting, design, and workforce considerations) have helped them contain costs.

- Customer engagement
  - Utilities noted that obtaining easements can be challenging, but customer outreach and education can help.

- Technical standards and operations
  - Depth and method of cover above the undergrounded lines were fairly standard across utilities surveyed, at 30 to 36 inches, and most utilities pull cable through conduit rather than direct burying electric cables.
  - In addition to undergrounding, utilities used a variety of alternative hazard mitigation approaches.

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Background & Methodology

Background and Methodology

Background

In 2021, PG&E initiated a large-scale program to underground electric distribution lines as part of its system hardening program. By the end of 2023, PG&E had buried nearly 500[5] miles of overhead power lines, and is on track to underground approximately 750 more by the end of 2026.

In order to learn and share best practices to drive safety, efficiency, scale, and continuous improvement, PG&E sought insights on how other utilities have approached undergrounding in the regions they serve.

In mid-2023, PG&E and its consultant conducted a benchmarking survey of 11 investor-owned electric utilities ("utilities") with active or planned strategic undergrounding programs, including PG&E itself. Strategic undergrounding programs are defined as those in which the utility chooses electric assets to underground with a goal of mitigating safety, reliability, or other risks.[6] Participating utilities serve the South, Midwest and West regions of the United States (US) as defined by the United States Census Bureau. Table 1 below shows the number of participants by US region.

Table 1: Number of Participants by US Region

Region	Participants
West	4[7]
South	4
Midwest	3

Benchmarking Purpose

This study seeks to document how participating utilities are pursuing strategic undergrounding in their service areas, what challenges they have faced, and what lessons they have learned.

Survey Methods

Participating utilities were identified through snowball sampling, in which early interviewees helped to identify additional participants. Each utility participant filled out an online survey (see survey questions in Appendix A) and took part in a follow-up interview. Questions in both the survey and interviews focused on scope of utilities' undergrounding programs; motivation to underground; site selection; program costs and cost containment approaches; as well as challenges utilities have faced and lessons they have learned.

Most survey questions were kept open-ended in order to solicit context for responses, but in some questions, participants were asked to choose from a menu of response options or to rank response

[5] PG&E typically reports this figure in underground miles. In this report, for consistency across utilities, miles have been converted to overhead miles removed. The conversion factor used is 1 mile overhead powerline to 1.25 miles underground powerlines, which is a conventional, industry-accepted conversion factor and also used by PG&E.
[6] Other undergrounding programs may convert overhead facilities to underground at the request of municipalities or property owners, or for other reasons.
[7] PG&E is included in the "West" region, and in the total number of 11 participants.

options, to allow themes to emerge across respondents. Once surveys were completed, PG&E and its consultant held follow-up interviews to further explore details and context.

The report is organized by key themes that emerged in surveys and interviews. Due to the small size of the sample, it focuses on qualitative information rather than quantitative analysis, and should be considered directional.

Results

Scope of Undergrounding Programs

Scale and Timeline

Participating utilities' programs vary in scale, from a significant portion of utilities' total distribution networks to small pilots.

Of the 11 utilities included in the study, the scale of strategic undergrounding completed to date, age of programs, and future plans vary. Participating utilities can be grouped into three categories based on the scale of their programs:

- ***Larger scope.*** Two utilities' programs were larger and more established. Each utility has completed more than 1,500 miles of strategic undergrounding — a significant portion of their total distribution networks — over the last decade. These utilities planned to continue undergrounding at a steady pace of 100 to 300 miles per year over the next 6 to 10 years.
- ***Moderate scope.***[8] Six utilities' programs were moderate in scope: they were initiated within the last 6 years, and have generally completed undergrounding of several hundred overhead miles.[9] Two of these utilities planned to expand their programs over the next several years, accelerating the pace of undergrounding to more than 500 overhead miles converted per year. The remaining four had more moderate or yet-to-be-determined future plans.
- ***Pilot or smaller scope.*** Three utilities' programs were in an early or pilot phase, and had smaller scopes. These programs were initiated within the last two years, and had undergrounded fewer than 5 overhead miles to date. Within this group, two utilities plan to maintain smaller programs in the near term, and one plans to scale its program up to several hundred miles total.

Table 2 summarizes the number of miles undergrounded to date, age of undergrounding program, and scope of future plans of these three groups.

[8] PG&E is included in this group.

[9] Five of the six utilities in this group have undergrounded 100 to more than 500 miles to date. The sixth utility has converted fewer than 100 overhead miles to underground, but more than utilities in the pilot group; that utility is included in this group because its program status and future plans are more consistent with the "moderate scope" utilities than the "pilot or smaller scope" utilities.

Table 2: Undergrounding Programs of Participating Utilities by Scope

	Larger Scope	Moderate Scope		Pilot or Smaller Scope
		With Larger-Scale Future Plans	Moderate or To-Be-Determined Plans	
Number of Utilities	2	2[10]	4	3
Overhead Miles Undergrounded to Date	1,500+ overhead miles	Generally, several hundred overhead miles[6]		Fewer than 5 overhead miles to date
Age of Program	Approximately 10 years	Initiated within the last 6 years		Initiated within the last 2 years
Scope of Future Undergrounding Plans	1,000 – 2,000 additional miles planned next 6 to 10 years, at a pace of ~100 – 300 miles per year.	Expanding program over next several years to convert more than 500 overhead miles to underground per year	Two utilities plan to convert ~100 – 200 overhead miles to underground per year over the next several years—with total planned mileage of more than 500 for one utility and nearly 1,500 for the other. Two utilities are developing future plans.	One utility plans to continue a pilot of fewer than 10 miles in the near term. Another plans to underground ~20 miles per year over the next several years. The third plans to scale its program up to underground several hundred miles total over the next several years.

Types of Assets Undergrounded

Most utilities are undergrounding primary distribution lines, secondary distribution lines, and service lines.

All participating utilities reported they are undergrounding electric distribution lines. Utilities may underground primary distribution lines, secondary distribution lines, and/or service lines that connect to customers' electricity meters.[11]

Seven utilities — including six with established strategic undergrounding programs and one with a pilot program — said they are undergrounding primary, secondary, and service lines. An eighth utility, whose strategic undergrounding program is currently in the pilot phase, said it plans to underground primary and secondary lines, but not service lines.

Within this group, four utilities are focused on undergrounding lateral or "tap" primary lines. Lateral or "tap" primary lines were defined as lines that are fused downstream of a feeder or 200A cable once undergrounded. The utilities primarily undergrounding lateral or "tap" primary lines cited targeting areas

[10] PG&E is included in this group.

[11] In this report, the term "primary" refers to a distribution line carrying voltage between a substation and a distribution transformer. Utilities may distinguish between "feeder" or main primary lines that carry power from substations to service areas, and "lateral" primary lines that carry power from feeders to specific portions of a service area; that distinction is not discussed in this report. The term "secondary" refers to a distribution line carrying lower-voltage power between a distribution transformer and service lines connected to customers' meters.

vulnerable to storm and vegetation-related outages in addition to the cost of undergrounding mainline or "feeder" lines as the primary reasons for focusing on lateral or "tap" primary lines.

In addition to the above, two utilities — one with an established strategic undergrounding program, and one whose program is transitioning from pilot into ongoing program for OH to UG conversion — reported that they underground or plan to underground secondary and service lines in certain cases or conditions.

The eleventh utility plans only to underground primary lines, and within that asset class, plans only to underground main or feeder lines.

In total, six utilities are undergrounding both main/feeder and lateral/"tap" primary lines, while four are undergrounding only lateral/"tap" lines and one only main/feeder lines. Eight utilities are undergrounding secondary and/or service lines, with two more undergrounding or planning to underground these lines in some cases.

Table 3: Number of Utilities Undergrounding Primary and Secondary Lines, by Type

	Primary Lines			Secondary and Service Lines				
	Main or Feeder	Lateral or Tap	Both	Secondary Only	Service Only	Both	In Some Cases	None
Number of Utilities	1	4	6	1	0	7	2[12]	1

[12] This group includes PG&E.

Motivation and Site Selection

Motivation

Utilities in the South and Midwest cited reliability and/or resilience to weather events as their main motivations for strategic undergrounding. Utilities in the West said they aim for their strategic undergrounding programs to reduce wildfire risk.

All seven participating utilities in the Midwest and South said the primary motivation behind their strategic undergrounding programs was to (1) improve reliability, (2) mitigate the impacts—including outages—of weather events such as storms, hurricanes, ice, and wind, or (3) both. Four (4) Southern or Midwestern utilities also reported that reducing maintenance costs was a secondary motivation for strategic undergrounding.[13]

All four participating utilities in the West[14] cited wildfire mitigation as the primary motivation for their undergrounding programs, with some noting public safety and environmental impacts in addition to risk reduction and reliability impacts. Western utilities also cited resilience to other natural disasters, such as storms, wind, and drought.

Site selection

Utilities selected sites based on metrics related to their motivation for pursuing strategic undergrounding: reliability metrics in the South and Midwest, and wildfire risk analysis in the West.

Among the six utilities in the Midwest and South who were far enough along in their undergrounding programs to have developed a formal site selection approach,[15] all used reliability metrics to select sites. The specific metrics varied by utility and included outage events per mile, Customer Average Interruption Duration Index (CAIDI) or System Average Interruption Duration Index (SAIDI), outage history and/or modeled risk of future outages. One utility noted it compares project cost to reliability benefits to determine the priority order in which to undertake undergrounding projects; another noted performing a cost-benefit analysis.

All four Western utilities[16] reported using a wildfire risk model to select sites for potential undergrounding and perform a cost-benefit analysis and/or assess feasibility to determine whether undergrounding or another mitigation is appropriate. Three Western utilities[17] also noted that they consider reliability risk in their project selection, including whether undergrounding can mitigate the risk of power shutoffs to address wildfire risk.

Across all regions, two utilities[18] noted that they consider construction feasibility when developing undergrounding work plans, for example, conducting work on geographically close sites at similar times—and noted that this strategy can reduce costs.

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[13] Participating utilities responded to an online survey in which they were asked to rank several response options from most to least important in terms of their company's motivation for pursuing strategic undergrounding**:** improving reliability and load capacity; demands from the public; increased frequency of damaging natural hazards; reducing maintenance costs; and "other." PG&E and its consultant also asked follow-up questions in phone interviews. Conclusion here are based on a combination of survey responses and follow-up interviews.
[14] Including PG&E.
[15] One utility whose program is in the pilot stage reported it does not yet have a formal selection process.
[16] Including PG&E.
[17] Including PG&E.
[18] Including PG&E.

Costs, Drivers, and Cost Containment

Unit Costs and Drivers

Unit costs are highly variable, and are affected by factors such as terrain and population density. On the whole, Southern and Midwestern utilities see lower costs than Western utilities.

PG&E and its consultant analyzed unit cost information shared by seven utilities with established strategic undergrounding programs.[19] A key theme raised by multiple utilities are that undergrounding costs can vary widely from project to project — and even ranges given for a "typical" project may not capture the full variability. Those seven utilities reported typical undergrounding unit costs that vary from approximately $300,000 to more than $3 million per overhead mile removed (all costs are presented in 2023 USD). It is important to note that costs may have limited comparability across and even within utilities, because indirect costs may be allocated differently by different utilities, costs differ by the type of asset being undergrounded[20] and method of construction,[21] and smaller, more nascent programs may face higher costs than larger, more established programs.[22] Other themes that drive cost variation include:

- **Terrain.** Four utilities noted that terrain features including hard rock, flood plains, water crossings, or soil type can affect ease and cost of construction. In particular, one utility noted that encountering unanticipated hard rock can drive up costs, because it impedes ability to execute a project as originally designed. When asked to rank the top challenges facing their strategic undergrounding programs, five[23,24] utilities ranked physical topography among the top two.
- **Population density and customer load base.** Two utilities noted that undergrounding costs are higher in more densely-populated areas, and a third noted higher costs in areas where customer load base is higher. A fourth utility noted that the need to obtain more easements can drive project costs up, and that the thoughtful use of existing easements where possible can help contain costs.
- **Region.** Typical undergrounding unit costs varied between $300,000 or less to $1.7 million per overhead mile removed among Southern and Midwestern utilities. Western utilities reported costs to date generally varied from $2.0 to $3.7 million per overhead mile removed, but one projected that future costs could rise to as much as $4.6 million per overhead mile removed.[25]

Supply Chain Issues

Several utilities noted negative impacts of a constrained supply of pad mount transformers.

Limits on the availability of key materials can stop or slow construction work and delays can increase project costs. Three utilities with established strategic undergrounding programs commented that a limited supply of pad mount transformers has presented challenges and/or caused delays in the second half of 2023; two of those utilities highlighted supply chain issues as the top challenge facing their programs. In addition, two utilities with undergrounding programs in the pilot stage reported that supply chain issues have also challenged their programs.

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[19] Because smaller or pilot programs unit cost estimates are based on at most a few completed miles, they are not included in this analysis. In addition, one utility with an established program declined to share unit cost estimates.
[20] For example, one utility noted that the cost of undergrounding a single-phase line was approximately 40% lower than that of undergrounding a 3-phase line, and that a 3-phase, large conductor line cost approximately 30% more to underground than a standard 3-phase line.
[21] For example, as noted by one utility, directional boring has higher costs than trenching.
[22] For this reason, programs in the pilot phase are excluded from this analysis.
[23] The utility that did not report its unit costs is included in this analysis.
[24] Including PG&E.
[25] Including PG&E.

As it waited for the supply of pad mount transformers to increase, one utility reported it had continued to install underground conduit and cable prior to receiving transformers, in order to avoid further program delays in the future.

Cost Containment Strategies

Utilities noted that economies of scale; contracting, design, and workforce considerations; and in one case, trench depth, have helped them contain costs.

PG&E and its consultant asked the eight utilities with established strategic undergrounding programs[26] about strategies they have used to contain costs. Themes common to multiple utilities were:

- ***Building economies of scale.*** Three utilities[27] noted that they have found cost efficiencies by undergrounding adjacent or nearby segments simultaneously or in sequence. The same three utilities also discussed finding cost efficiencies through larger-scale purchases or longer-term contracts, or providing contractors with a consistent level of work to enable them to maintain a steady workforce level.
- ***Unit pricing and other contract considerations.*** Five utilities in total described contracting approaches that have helped them to contain costs. Two reported signing turnkey, unit-priced contracts with vendors. A third reported it is moving toward fixed pricing, and currently limits change orders. A fourth noted that it is negotiating construction allowance agreements to limit unanticipated costs. A fifth noted that competitive bidding has generally helped it to drive undergrounding costs down. One utility further noted that it tracks contractor performance metrics such as on-time completion of work.
- ***Design considerations.*** Six utilities in total[28] noted that they have found that efficient or careful system design, exploring alternative design options, or ensuring design-build alignment can help contain costs.
- ***Depth of cover and method of trenching.*** Two utilities noted that they have reduced depth of cover (also referred to as trench depth) where possible as a cost containment strategy; another noted that it was piloting shallower trenches that could work in some locations.[29] A fourth utility reported that its use of directional boring, rather than trenching, may increase costs.
- ***Workforce.*** Two utilities noted the importance of maintaining a qualified skilled workforce to contain costs. Two utilities reported using a project management office to oversee the end-to-end undergrounding process and identify process efficiencies.

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[26] Eight in total — all those with large or moderately-sized programs, including the utility that did not share unit costs.
[27] Including PG&E.
[28] Including PG&E.
[29] While PG&E and its consultant collected data on depth of cover from the majority of participating utilities, due to small sample size and the number of other factors that vary between utilities, a clear pattern relating cost and depth of cover did not emerge across participants.

Customer Engagement

Easements and Customer Outreach

Utilities noted that obtaining easements can be challenging, but customer outreach and education can help.

Among the eight utilities with established strategic undergrounding programs, six noted that they have encountered challenges obtaining easements, or that complexities of obtaining easements have led to project delays.[30] In addition, two of three utilities with programs in the smaller or pilot stage noted the challenges of obtaining easements. One utility observed that it is important to build trust when working on customers' property.

In response to the challenges that obtaining easements can pose, two utilities with established strategic undergrounding programs noted they have invested significantly in customer outreach and education. For example, one utility noted that it hired a stakeholder engagement manager to support community engagement, and that it works to educate customers through door hangers, calls, and emails. Another utility reported that for its strategic undergrounding program, which includes the undergrounding of service lines, it initiates customer outreach approximately one year before it plans to begin construction work. That utility also noted that it has found benefit in engaging with local elected officials as a first step, because customers may reach out to their elected representatives with questions about the undergrounding effort.

Technical Standards and Operations

Method and Depth of Cover

Depth and method of cover were found to be fairly standard across utilities surveyed, at 30 to 36 inches, and most utilities pulled cable through conduit.

PG&E and its consultant surveyed utilities on the depth at which they typically bury power lines, as well as the standard method of cover they use.[31] PG&E asked respondents to choose from a list of possible methods of cover: pulling cables through conduit (inserting electrical cables into a protective tube); direct bury in a trench; or pre-casting in conduit (laying cables in a concrete mold).

- ***Depth of cover.*** Nearly all participating utilities (9) reported a standard depth of cover between 30 and 36 inches for primary lines. Three utilities reported a standard of 30 inches, three reported 36, and the remaining three[32] reported following a standard of 30 to 36 inches, depending on project specifics including terrain. A tenth utility reported following a standard of 40 inches of cover for primary main lines.[33] In addition, three utilities reported that they bury secondary lines approximately six inches less deep than primary lines.

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[30] Easements refer to a utility's right to access and control the portion of a customer's property that is located near a utility or structure. A utility that needs to underground on a customer's property must obtain an easement in order to undertake construction.
[31] Analysis for this section includes utilities whose programs are in a smaller or pilot stage.
[32] Including PG&E.
[33] The eleventh utility did not report on depth of cover.

- ***Method of cover.*** Eight of 11 utilities[34] reported pulling cable through conduit as their standard method of cover. Two reported using direct bury as their standard, and the final utility reported using both methods depending on the project. No utilities reported pre-casting cable as a standard practice.

Alternative Approaches

In addition to undergrounding, utilities used a variety of alternative hazard mitigation approaches.

In addition to questions about their strategic undergrounding programs, PG&E and its consultant also asked participating utilities[35] about other hazard mitigation strategies they have implemented.[36] The most popular responses included the installation of stronger and more resilient utility poles and/or overhead covered conductor, vegetation management, removal of power lines with or without conversion to remote grid, and proactive power shutoffs. One participant specifically mentioned removing powerlines on roadways. Participants also discussed operational mitigations including safety settings that turn off power quickly when a fault or object strike occurs on a line, early fault detection, and/or Rapid Earth Fault Current Limiter (REFCL), as well as cameras/machine learning-driven image analysis and the installation of additional weather stations.

Conclusion

This report provides a sense of the range of scale, approach, cost, and technical standards among participating utilities' strategic undergrounding programs. Generally, programs focus on addressing climate-related risks most likely to affect the region — wildfire risk in the West and storm-related issues in the Midwest and South. Utilities note a variety of cost-containment strategies. PG&E hopes that utilities, policymakers, and other stakeholders can learn from this report.

[34] Including PG&E.
[35] Including those whose programs are smaller or in a pilot stage.
[36] PG&E and its consultant asked about alternative approaches in the online survey. Utilities could select all applicable choices from a list or enter their own values. In the table, the following were respondent-input values: removal of powerlines on roadways, early fault detection, cameras and machine learning-driven image analysis, and weather station network. The other alternative mitigations noted were choices provided in the survey.

Appendix A:
Survey Questions

Utility Undergrounding and Natural Hazard Risk Mitigation Survey

As the frequency, intensity, and risks of natural disasters have increased for the power and utilities industry, Pacific Gas and Electric Company (PG&E) is hoping to collaborate with you to better understand how you are using your undergrounding program to mitigate these significant risks and consequences for your customers, communities, and company.

The following questions are designed to help us understand the various details and metrics that you use to inform and support your decisions to underground or to pursue other alternative risk mitigations. We may use the information you share in our 10-year Undergrounding Plan, which is being prepared for public filing this year. Therefore, please let us know in advance if any of the information that you choose to share is sensitive in nature and should not be disclosed to the public.

Company/Contact Information

In this section we will ask for your company name and contact information (for internal purposes only).

1. Please provide the name of your company.
2. Please provide your full name.
3. Please provide your title and group name within your organization.
4. Please provide your email.
5. Please provide your phone number.

Reasons to pursue undergrounding

In this section we will ask you questions pertaining to your company's motivation for undergrounding, and any restrictions and benefits your company faces.

6. Please rank your company's motivation for undergrounding from most important to least important.
   Options:
   - *Increased frequency of damaging natural hazards*
   - *Improving reliability and load capacity*
   - *Reducing maintenance costs*
   - *Demands from public*
   - *Other*
7. Please describe the other reasons that your company would consider undergrounding as it relates to question 6 (if any).
8. What are the most prevalent and consequential natural hazards that your service region faces?
9. What is the scale of undergrounding that your company has planned and completed (e.g., Total underground miles completed to date per year, total undergrounding miles targets in 2023, 2024, 2025, 2026 (if available)).
10. What assets are included in your undergrounding program? (Mark all that apply)
    Options:
    - *Transmission lines*
    - *Primary distribution lines*
    - *Secondary distribution lines*
    - *Service lines*
    - *Other*

11. What are the primary benefits for pursuing undergrounding that your company is articulating publicly? Please link any relevant public filings, reports or websites we can refer to (or share attachments in separate follow-up).
12. Please rank the following factors that make undergrounding challenging from most challenging to least challenging.
    Options:
    - *Cost*
    - *Physical topography*
    - *Market construction capacity*
    - *Regulatory hurdles*
    - *Other*
13. Please describe "other" in response to question 12 (if any).
14. Do you face regulatory hurdles or resistance in deploying or expanding your undergrounding program? If so, please explain the primary feedback and issues.
15. What alternatives / hazard mitigation strategies to undergrounding have you implemented in addition to and/or instead of undergrounding?
    Options:
    - *Installing overhead covered conductor*
    - *Removing powerlines*
    - *Proactive Power Shutoffs*
    - *Vegetation Management*
    - *Advanced Powerline Safety Settings*
    - *Remote grids*
    - *REFCL: Rapid Earth Fault Current Limiter*
    - *Installing stronger / more resilient poles*
    - *Other*
16. Please list out and describe the primary drivers for pursuing the top three (3) alternatives / hazard mitigation strategies prioritized above in question 14?

Metrics and quantifiable benefits to undergrounding

In this section we will ask you questions pertaining to parties affected by your undergrounding, benefit metrics, and your benefit monetization approach.

17. Have you performed a quantitative Cost Benefit Analysis on your undergrounding program and/or alternative solutions?
    Options:
    - *Yes*
    - *No with no future plans*
    - *Not yet*
18. What reliability metrics are being used (if any) by your company specific to undergrounding?
19. What public safety metrics are being used (if any) by your company specific to undergrounding?
20. Please list all other benefit metrics of undergrounding used by your company (e.g. unit cost / mile, total risk reduction, etc.).
21. Please list the qualitative and/or quantitative benefits of undergrounding to your customers.
22. How does undergrounding impact customer rates (if available) (e.g., avg. annual bill impact)?
23. Please list the key qualitative and quantitative benefits of your undergrounding program to the wider community (e.g., societal benefits).
24. Have you identified how undergrounding affects customers in disadvantaged communities in your service area? If so, how do you quantify this?

25. Do you monetize the quantified benefits?
    Options:
    - *Yes*
    - *No*
    - *Sometimes*
26. What method(s) do you use to prioritize which circuits to underground?
    Options:
    - *Cost benefit analysis*
    - *Risk analysis*
    - *Other*
27. Please list the benefit metrics that you use in your risk mitigation prioritization method.
28. When valuing risk, do you make modifications to outcomes to account for people's attitudes towards low probability-high loss events (e.g., risk premium variations for catastrophic wildfires or storms)?
29. Does your Cost Benefit Analysis consider a range of probability losses (e.g., low to catastrophic)? If so, how?

Undergrounding Standards

In this section we will ask you questions pertaining to some technical standards (method and depth of cover) used in your undergrounding.

30. What is your standard method of cover?
    Options:
    - *Direct bury*
    - *Pull cable through conduit*
    - *Precast cable in conduit*
    - *Other*
31. What is your standard depth of cover over underground electric distribution primary cables or conduit?
32. When you deploy the minimum depth of cover over underground electric distribution primary cables or conduit, do you deploy any specific risk mitigations to protect the shallower lines?

Undergrounding Costs

In this section we will ask you questions pertaining to undergrounding costs.

33. What is the range of your total program budget for undergrounding? Please provide the annual cost or range of years that is included in your program budget.
34. What is your unit cost per mile (or range of unit cost per mile) for undergrounding?
35. What is the estimated change ($ and % change by year) in operating costs, routine maintenance costs, and major maintenance costs?
36. What strategies or technologies are you using to reduce the cost of undergrounding?
37. How do you estimate the end-of-life capital replacement costs for your system (cost approach and useful life of asset assumptions) and the cost to rebuild your company’s affected assets in the event of a catastrophic impact to your system?

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