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A Method to Estimate the Costs and Benefits of Undergrounding Electricity Transmission and Distribution lines

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Abstract:
There has been a general shortfall of peer-reviewed literature identifying methods to estimate the costs and benefits of strategies employed by electric utilities to improve grid resilience. This paper introduces—for the first time—a comprehensive analysis framework to estimate the societal costs and benefits of implementing one strategy to improve power system reliability: undergrounding power transmission and distribution lines. It is shown that undergrounding transmission and distribution lines can be a cost-effective strategy to improve reliability, but only if certain criteria are met before the decision to underground is made.

Keywords:
Electric system reliability; grid resilience; power outages; undergrounding; cost-benefit analysis

Classification Codes:
Q4 Energy; Q5 Environmental Economics; R00 General; O2 Development Planning and Policy

1. Introduction

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—especially within the context of decisions to underground transmission and distribution (T&D) lines (e.g., EEI 2013; Nooij 2011; Brown 2009; Navrud et al. 2008). One study found that the costs—in general—of undergrounding Texas electric utility T&D infrastructure were "far in excess of the quantifiable storm benefits" (Brown 2009). However, this same study also noted that targeted storm-hardening activities may be cost-effective. Despite the importance of considering indirect (external) costs and benefits, policymakers have not always recognized their use within the economic evaluation of proposed policies (Arrow et al. 1996). It is possible that grid resiliency initiatives could pass a societal benefit-cost test, yet fail a private benefit-cost test and, ultimately, not be mandated by a public utility commission. Transparent assessments of the costs and benefits of undergrounding and other grid-hardening activities are useful to policymakers interested in enabling the long-term resilience of critical electricity system infrastructure (Executive Office of the President 2013a).

Larsen et al. (2015) found that U.S. power system reliability is generally getting worse over time (i.e., average annual interruption durations are increasing), due in large part to impacts associated with increasingly severe weather. This study also found that customers of utilities with a relatively larger share of underground line miles typically experienced less frequent and total minutes of power interruptions when compared to utility customers in places that had a lower share of undergrounded line miles.

The purpose of this study is to expand on research by Larsen et al. (2015) by systematically evaluating a policy that requires investor-owned utilities (IOUs) to bury all existing and future transmission and distribution lines underground. More specifically, this analysis will attempt to address the following questions:

- What are the lifecycle costs of undergrounding all existing and new transmission and distribution lines at the end of their useful lifespan?
- Could increasing the share of underground T&D lines lead to fewer power interruptions—and are there corresponding monetary benefits from this reduction?
- Are there aesthetic benefits from reducing the number of overhead T&D lines?

- How much might health and safety costs change if there is an extensive conversion of overhead-to-underground lines?
- How much might undergrounding transmission and distribution lines affect ecosystem restoration costs?
- How important are assumptions, including value of lost load estimates, relative to one another within a decision to underground power lines?
- What are the minimum conditions necessary for a targeted undergrounding initiative to have net social benefits?

This article is organized as follows. Section 2 provides background on the causes of power outages, how electric system reliability is measured, and undergrounding. Section 3 contains a discussion of the over-arching analysis framework including study perspective, standing, and methods. Results and a sensitivity analysis are presented in Section 4. Section 5 concludes with a policy recommendation, discussion of the analysis shortcomings, and highlights potential areas for future research.

2. Background

The IEEE guide 1366-2012 formally defines a number of metrics to track electric utility reliability (IEEE 2012). The System Average Interruption Frequency Index (SAIFI) is one of the most commonly used metrics to assess electric utility reliability (Eto et al. 2012)[1]. Equation 1 shows that annual SAIFI for a utility is calculated by summing all annual customer interruptions and dividing this number by the total number of customers served. In this equation, the number of customers affected by all events in year t is $Affected_t$ and the total number of customers served by the utility in a given year is $Customers_t$.

$$SAIFI_t = \frac{\sum Affected_t}{Customers_t} \tag{1}$$

An IEEE survey of 106 utilities found that the median 2012 SAIFI value is 1.5 interruption events for a typical customer (IEEE 2013).

[1] Although not the focus of this analysis, other popular reliability metrics include the System Average Interruption Duration Index (SAIDI) and Customer Average Interruption Duration Index.

It follows that burying power lines (i.e., "undergrounding") would mitigate some of the risk associated with weather-related events (EEI 2013). In 2012, the Department of Energy reported that "calls for undergrounding are common from customers, elected officials, and sometimes state utility commissions. However, undergrounding is costly and the decisions are complex" (USDOE 2012). According to a U.S. Department of Energy press release, widespread power outages, which are often caused by severe storms, "inevitably lead to discussions about burying electric utility T&D infrastructure" (USDOE 2012). Coincidentally, just three months after this press release, "Superstorm Sandy"—a large hurricane affecting the U.S. Eastern Seaboard—caused power outages for tens of millions of people with damages estimated in excess of $50 billion dollars (NOAA 2013). For nearly sixty years, researchers have acknowledged that reliable electric service (or lack thereof) has economic benefits (costs) to society (Larsen 2016). As the electric industry evolved over this time period, so have the methods used by researchers to value lost load (VLL). For example, Sullivan et al. (2009) collected and organized information from nearly thirty value-of-service reliability studies undertaken by ten U.S. electric utilities noting that:

> "…because these studies used nearly identical interruption cost estimation or willingness-to-pay/accept methods it was possible to integrate their results into a single meta-database describing the value of electric service reliability observed in all of them. Once the datasets from the various studies were combined, a two-part regression model was used to estimate customer damage functions that can be generally applied to calculate customer interruption costs per event by season, time of day, day of week, and geographical regions within the U.S. for industrial, commercial, and residential customers."

Earlier studies can provide a basis for estimating the avoided damages from strategies to improve grid resilience (e.g., Sullivan et al. 2009; 2010; Leahy and Tol 2011). Brown (2009) conducted a narrow cost-benefit analysis of storm hardening strategies on behalf of the Public Utility Commission of Texas. This study indicated that undergrounding T&D lines is significantly more expensive when compared to traditional overhead installations. Brown (2009) assumed that converting existing overhead transmission lines to underground lines would cost approximately $5 million per mile.[2] For comparison, Brown (2009)

[2] EEI (2013) reported a minimum overhead-to-underground transmission line conversion cost of $536,760–$1,100,000/mile and a maximum conversion cost of $6,000,000–$12,000,000. EEI (2013) reported a minimum overhead-to-underground distribution line conversion cost range of $158,100–$1,000,000/mile and a maximum conversion cost range of $1,960,000–$5,000,000. The Edison Electric Institute (EEI) estimates that the minimum replacement costs for overhead transmission lines range from $174,000 per mile (rural) to $377,000 (urban). The maximum replacement costs for existing overhead transmission lines ranges from $4.5 million/mile (suburban) to $11 million/mile for urban customers (EEI 2013). EEI (2013) also reported that installing new underground

indicates that it costs ~$180,000/mile to replace single, wood pole transmission lines and ~$459,000/mile to replace state-of-the-art, overhead transmission lines that meet current National Electric Safety Code (NESC) standards.[3] Brown (2009) estimated that undergrounding local overhead distribution lines would cost ~$1 million per mile. For comparison, the minimum replacement costs for existing overhead distribution lines ranged from $86,700 to $126,900/mile with maximum replacement costs ranging from $903,000 to $1,000,000 (EEI 2013).

It is unfortunate, but likely that replacing a large amount of overhead infrastructure with underground infrastructure will lead to relative increases in risk to utility operational staff working in the field. EEI (2013) indicates that undergrounding infrastructure has "created a significant safety hazard for crews attempting to locate and repair failed equipment." For this reason, it was assumed that worker health and safety costs will increase—above levels observed with the status quo—as the share of underground lines increases.

Reducing risk of power outages from severe storms is not the only reason given by stakeholders during discussions about burying T&D lines. Aesthetic improvements are a commonly listed benefit of undergrounding electric utility infrastructure (Brown 2009; EEI 2013; Navrud et al. 2008; Headwaters Economics 2012). EEI (2013) notes that utility customers "prefer underground construction" with "customer satisfaction" and "community relations" being the primary benefit of undergrounding. For example, the community of Easthampton, New York issued a stop-work order and threatened to sue the local utility, PSEG Long Island, over their plan to build new high-voltage transmission lines (Gralla 2014). This community and others are advocating for the undergrounding of future high-voltage transmission lines.

Des Rosiers (2002) found that a direct view of a transmission system pylon or conductors had a significantly negative impact on property prices with lost values ranging from -5% to -20% depending on the distance from the overhead infrastructure to the residence. Sims and Dent (2005) also evaluated how property prices changed based on proximity to high-voltage overhead transmission lines. Sims and Dent studied four different types of property and found that the relationship is not linear, but that there was a ~10%–18% reduction in value for semi-detached properties and a ~6%–13% reduction for detached

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distribution lines costs from $297,200-$1,141,300/mile (minimum) to $1,840,000–$4,500,000/mile (maximum). EEI noted that installing new underground transmission lines costs from $1,400,000–$3,500,000/mile (minimum) to $27,000,000-$30,000,000/mile (maximum).

[3] Brown (2009) assumes that future costs and benefits are discounted 10% annually. In addition, underground and overhead T&D infrastructure have forty- and sixty-year lifespans, respectively.

properties. Furthermore, properties having a rear view of a pylon were found to have their value reduced by ~7%. By comparison, the negative impact on value for property having a frontal view was found to be greater (14.4% loss).

Both overhead and underground electric utility infrastructure affects the natural environment and the services that these ecosystems provide. As discussed earlier, wildlife (e.g., squirrels, birds) die prematurely because of the presence of overhead electric utility infrastructure, and in doing so, cause reliability problems. The U.S. Fish and Wildlife Service estimates that collisions with power transmission and distribution lines "may kill anywhere from hundreds of thousands to 175 million birds annually, and power lines electrocute tens to hundreds of thousands more birds annually" (Manville 2005). Undergrounding lines may reduce mortality rates of birds, rodents, and squirrels, but the process of installing underground power delivery infrastructure could significantly disturb sensitive wetlands (Jones and Pejchar 2013), forests (Most and Weissman 2012), or other valuable ecosystems within the T&D corridor. It is likely that undergrounding infrastructure will *increase* the area of environmental disturbance—when compared to traditional overhead line replacement (Public Service Commission of Wisconsin 2013). Measurement of the total economic value of an ecosystem is a controversial and difficult undertaking (e.g., Loomis et al. 2000). Goulder and Kennedy (2009) discuss the value of ecosystem services within a benefit-cost analysis framework. It is noted that:

> "…when a portion of the ecosystem is threatened with conversion, it may be more important to know the change or loss of ecosystem value associated with such conversion than to know the total value of the entire original ecosystem….*willingness to pay* offers a measure of the change in well-being to humans generated by a given policy change to protect nature or environmental quality. No comparable measure is currently available for assessing changes in satisfaction to other species or communities of them" (Goulder and Kennedy 2009, p. 18).

The purchase of conservation easements is one way that developers are able to mitigate some or all of the lost value of an ecosystem affected by specific development projects (The Nature Conservancy 2014). Developers often purchase conservation easements in locations with similar habitats to the corridor that was affected by the development activity. For example, if new power lines were installed across a prairie habitat in Texas, a developer would be allowed to purchase a conservation easement for comparable land somewhere else.

2.1 Texas (U.S.) as Case Study

Although the model described in this article has universal applicability, it was initially configured for Texas investor-owned utilities. Texas was selected for a number of reasons including: (1) the Brown (2009) study of Texas contained a number of important assumptions about the cost and lifespan of T&D infrastructure; (2) Texas has a mix of urban and rural areas, which extends the applicability of this model to other regions; (3) Texas policymakers have expressed interest in the financial viability of an undergrounding mandate; and (4) these service territories are consistently exposed to severe weather.

Figure 1 shows the average SAIFI values for all Texas utilities used in the Larsen et al. (2015) study without and with major events (i.e., severe storms) included. The pronounced effect of major events on the frequency of outages can be seen in this figure. The figures show a fairly flat time trend for the reliability data without major events, but a slightly increasing trend for the frequency of outages with the inclusion of major events.

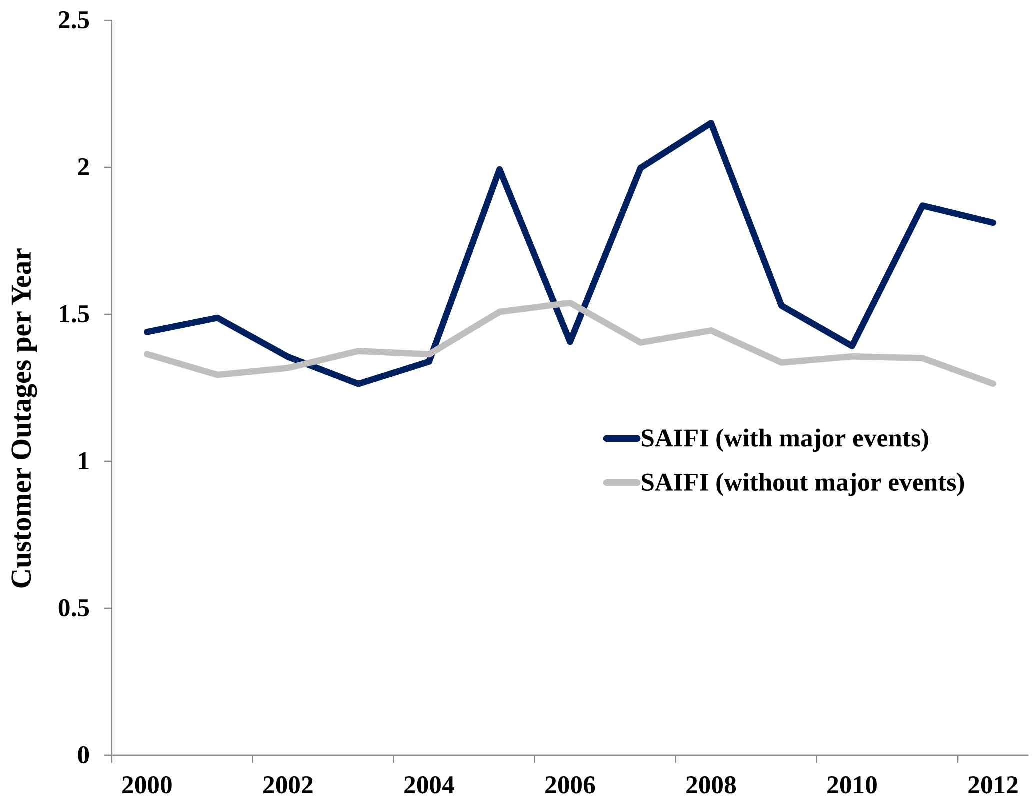

Figure 1. System average interruption frequency index over time—annual average of all Texas utilities

3. Analysis Framework and Method

This analysis is conducted from the perspective of any individual who cares about maximizing net social benefits. There are a number of stakeholders in this type of analysis including the state government, electric utility ratepayers, electric utilities, developers of T&D infrastructure, and society (i.e., all state residents). Given resource constraints, this preliminary analysis assumes that all additional costs to utilities associated with undergrounding will be passed along to ratepayers—including additional administrative, permitting, and siting expenses. Given this key assumption, the stakeholders with standing in this analysis are IOUs, utility ratepayers, and all residents within the service territory.

This analysis evaluates impacts of a policy ("require undergrounding") against a baseline ("status quo"). In the following sections, the benefits and costs were evaluated for a policy that requires investor-owned Texas electric utilities to underground (1) existing T&D lines at the end of their useful life; and (2) when new infrastructure is needed to meet projected growth.

Table 1 describes a range of possible impacts (costs and benefits) for each alternative and group with standing (see above). It is expected that utility ratepayers will bear the cost burden as utilities pass-through all of the costs to install and maintain underground power lines. The largest beneficiaries of policies to encourage undergrounding of power lines would be the state's residents.

Table 1. Potential impacts from a policy requiring the undergrounding of T&D lines

Key Stakeholders	**Undergrounding Mandate**	
	Selected Costs	**Selected Benefits**[4]
IOUs	• Increased worker fatalities and accidents	
Utility ratepayers	• Higher installation cost of underground lines • Additional administrative, siting, and permitting costs associated with undergrounding[5]	• Lower operations and maintenance costs for undergrounding[6]

[4] Other potential impacts not evaluated in this study include societal benefits from improved local/regional/national security and changes to the likelihood of electrocution to the general public.

[5] It is assumed that an administrative, permitting, and siting fee (% share of the total circuit replacement cost) is levied by the government against the utilities in the year before the first conversion decision. For example, if a utility converts an overhead transmission line to an underground transmission line in 2020, a proportional fee (e.g., 2%) is assessed in 2019 and discounted back to the present. In this analysis, this government fee (i.e., tax) is considered a

	• Increased ecosystem restoration/right-of-way costs	
All residents within service area		• Avoided costs due to less frequent power outages[7] • Avoided aesthetic costs

In general, this analysis involved predicting and monetizing impacts for five distinct categories: (1) lifecycle infrastructure costs including administrative, permitting, and siting costs; (2) avoided costs from less frequent power interruptions; (3) reduced aesthetic costs; (4) increased health and safety costs; and (5) increased ecosystem restoration costs. The stream of benefits and costs were evaluated from 2013 through 2050—the approximate lifespan of an underground T&D line installed in 2012. All future benefits and costs were discounted back to the present using a typical utility weighted average cost of capital (Brown 2009; Public Utilities Fortnightly 2013).

3.1 Lifecycle Infrastructure Costs

In this section, an empirical method is introduced to estimate the "status quo" and undergrounding-related costs associated with replacing and maintaining existing overhead T&D infrastructure, installing new overhead (underground) T&D infrastructure, and converting existing overhead infrastructure to underground lines. Determining the lifecycle costs of infrastructure involved a number of important steps including (1) collecting basic information on the total line mileage and replacement (i.e., conversion) and operations and maintenance (O&M) costs of T&D infrastructure that is currently overhead and underground for IOUs operating in Texas (Brown 2009; EEI 2013); (2) randomly determining the age and length of each segment (i.e., circuit) of existing overhead and underground infrastructure; (3) and calculating the net present replacement and O&M costs of T&D infrastructure through 2050 for a status quo and undergrounding mandate.

As discussed earlier, Brown (2009) and EEI (2013) report the costs of replacing and converting both overhead and underground T&D infrastructure. In addition, Brown (2009) provides useful summary

deadweight loss to society, because this form of government revenue is not recycled back into the economy (Boardman et al. 2011). It is assumed that utilities will include this fee in the cost of line replacement or conversion.

[6] Anecdotal evidence suggests that O&M expenses are lower for undergrounded systems (e.g., significant savings accrue from reduced vegetation management expenditures). However, there is little or no published information describing annual O&M cost differences between underground and overhead T&D systems. For the Texas case, it is assumed that the percentage share of replacement costs that represent operations and maintenance costs are the same between overhead and underground systems.

[7] Evaluation of the avoided costs due to shorter duration outages is beyond the scope of this initial analysis.

statistics that describe the total number of T&D miles currently overhead and underground for the following Texas IOUs: TNMP, Oncor, Entergy Texas, Centerpoint, SWEPCO, AEP TX North, and AEP TX Central. Table A-1 in the Technical Appendix shows the existing number of T&D miles assumed for this study, the assumed costs for the T&D lines, and a number of other key assumptions.

Unfortunately, there are no publicly-available sources of information identifying the current age, location, or length of overhead and underground T&D line segments across Texas.[8] The timing of when these T&D costs materialize and any associated benefits accrue will determine how much future costs and benefits will need to be discounted back to the present. Therefore, the next step in estimating the lifecycle costs of infrastructure involved randomly generating the current age and length of each line circuit up to the total mileage for all IOUs operating in Texas.[9] Equations 2-4 describe how each segment, i, of existing infrastructure was randomly assigned an age using a statistical technique to approximate a observed statistical distribution that appears lognormal (StackExchange 2015). Unfortunately, the average age of overhead and underground transmission and distribution lines located in Texas could not be easily determined. For this reason, publicly-accessible information was used to describe average ages ($\overline{\text{Age}_x}$) for underground and overhead T&D systems located in other Western states (Northwestern Energy 2011; Southern California Edison 2013). Northwestern Energy recently filed a report with the Montana Public Service Commission that contained an overhead distribution system "age profile" (i.e. histogram of electricity infrastructure ages) (Northwestern Energy 2011). The shape of this distribution was approximately normal with a slight skew to the right. Accordingly, the shape of this 2012 age profile was estimated—for Texas—using the average age for underground and overhead T&D line circuits and repeatedly drawing from a gamma distribution (SAS Institute 2015) that is scaled (Equation 2), shaped (Equation 3), and lower-bounded at zero (StackExchange 2015). Throughout this article, the subscript *x* refers to overhead transmission (x=1) and distribution (x=2) lines and underground transmission (x=3) and distribution (x=4) lines.

$$\text{Scale}_x^{\text{Age}} = \frac{\left(\frac{\overline{\text{Age}_x}}{2}\right)^2}{\overline{\text{Age}_x}} \tag{2}$$

[8] In this analysis, it is assumed that a line segment is analogous to a "circuit". However, it is likely that what is referred to as a segment may be much longer than a typical T&D line circuit. For this preliminary analysis, it is assumed that electric utilities will replace or convert each circuit (segment) independently.
[9] It is assumed that the total T&D line mileage grows at 2% per year.

$$\text{Shape}_{\text{x}}^{\text{Age}} = \frac{\overline{\text{Age}_x}}{\left(\frac{\overline{\text{Age}_x}}{2}\right)^2} \tag{3}$$

Equation 4 denotes the randomly determined circuit age (in 2012) where z is a positive observation generated from the gamma probability distribution (SAS Institute 2015).

$$\text{Age2012}_{\text{i}} \sim \text{Scale}_{\text{x}}^{\text{Age}} \left(\frac{1}{\Gamma\left(\text{Shape}_{\text{x}}^{\text{Age}}\right)}\right) \text{z}^{\text{Shape}_{\text{x}}^{\text{Age}}\text{-1}} e^{\text{-z}},\ \text{z} > 0 \tag{4}$$

For example, Figure 2 is a histogram of existing overhead distribution line circuit ages that were simulated using this technique.

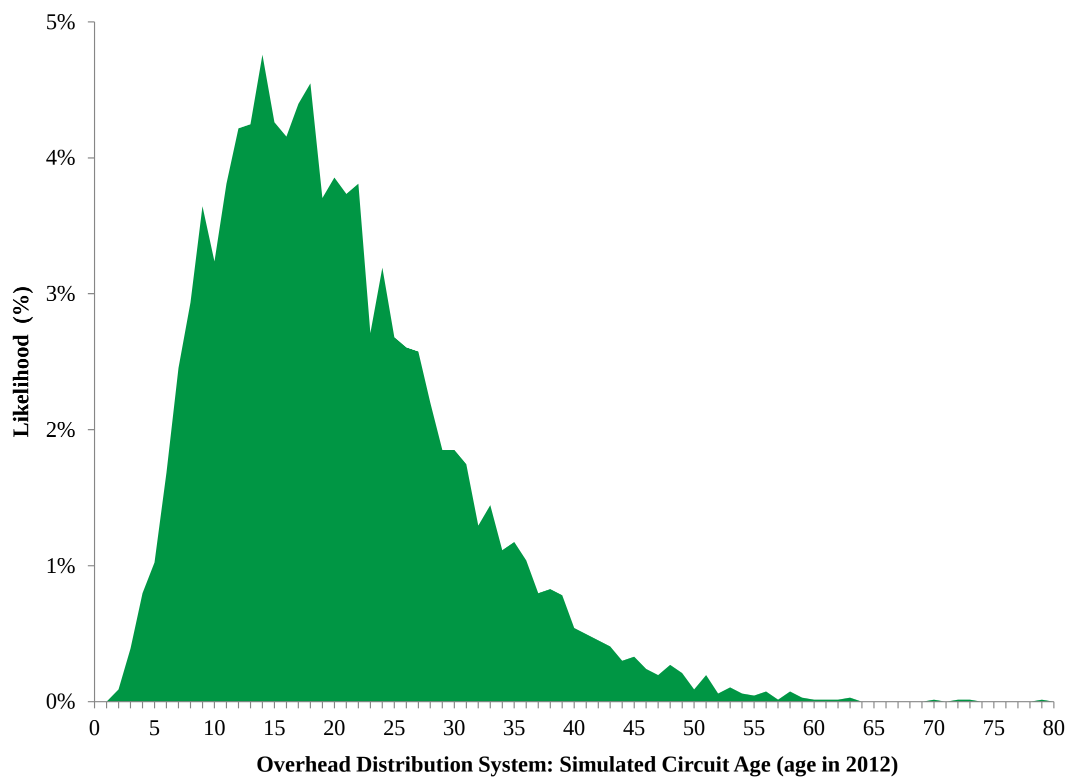

Figure 2. Simulated age profile of Texas IOU overhead distribution lines

Individual circuit length was determined following a similar process to what is described above for generating circuit ages (see Equations 5–7). In this case, an assumption was made about the average circuit length ($\overline{\text{Length}}_x$), in miles, for underground and overhead T&D systems.

$$\text{Scale}_x^{\text{Length}} = \frac{\left(\frac{\overline{\text{Length}}_x}{2}\right)^2}{\overline{\text{Length}}_x} \tag{5}$$

$$\text{Shape}_x^{\text{Length}} = \frac{\overline{\text{Length}}_x}{\left(\frac{\overline{\text{Length}}_x}{2}\right)^2} \tag{6}$$

$$\text{Length}_i \sim \text{Scale}_x^{\text{Length}} \left(\frac{1}{\Gamma\left(\text{Shape}_x^{\text{Length}}\right)}\right) z^{\text{Shape}_x^{\text{Length}}-1} e^{-z},\ z > 0 \tag{7}$$

Figure 3 is a histogram of existing overhead distribution line circuit lengths that were simulated using this technique. Note that the integral of this distribution is an estimate of the total mileage of overhead distribution lines operated by Texas IOUs in 2012 (i.e., 165,141 miles simulated versus 165,158 actual overhead distribution lines).

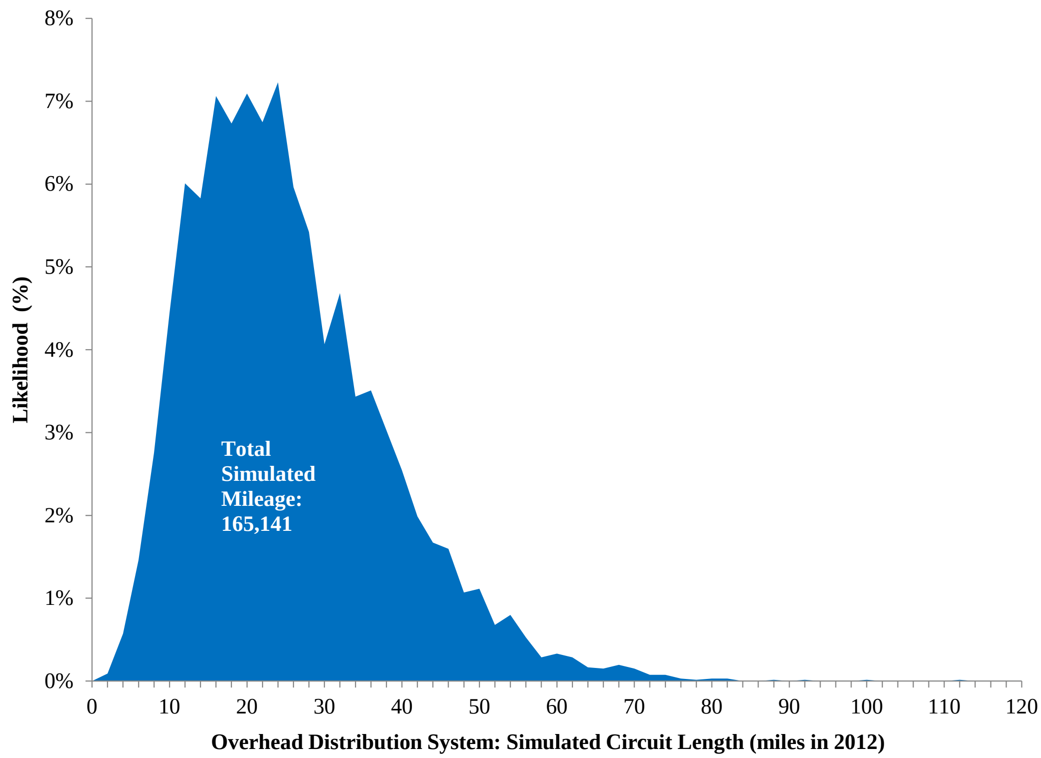

Figure 3. Simulated mileage profile of Texas IOU overhead distribution lines

A lifecycle analysis of T&D line costs through 2050 can be conducted with information on the circuit age in 2012, the length, expected useful lifespan, and replacement and O&M costs for all underground and overhead infrastructure. Equations 8-15 describe a technique to calculate the "true economic depreciation" of infrastructure (Samuelson 1964; Larsen et al. 2008; Heal 2012)[10]. Under the status quo, it is assumed that overhead (underground) infrastructure is replaced at the end of its useful lifespan with the same type of infrastructure (overhead is replaced with overhead, underground is replaced with underground). Equation 8 denotes how the age of each circuit into the future was determined given the age of the circuit in the base year ($Age2012_i$), its expected lifespan ($Lifespan_x$), and whether or not it was replaced in any given future year.

[10] A variation of this method was used to estimate the additional costs to Alaska's infrastructure from the impacts of rapid climate change (Larsen et al. 2008).

$$\text{Age}_{it} = \begin{cases} \text{Age2012}_i + (t - 2012),\ \text{if Age}_{it} \leq \text{Lifespan}_x \\ 1,\ \text{if Age}_{it} - \text{Lifespan}_x = 1 \\ \text{Age}_{it\text{-}1} + 1,\ \text{if Age}_{it} - \text{Lifespan}_x > 1 \end{cases} \quad : \forall\ i,t,x \tag{8}$$

It is possible that overhead and underground T&D line replacement costs may increase (decrease) from the initial replacement cost assumption for the base year (i.e., 2012). Equation 9 depicts how line (x) replacement costs (ReplCost) could increase (decrease) linearly in time, t, at an annual growth (decay) rate expressed as Ψ_x.

$$\text{ReplCost}_{xt} = \begin{cases} \text{ReplCost}_x,\ \text{if } t = 2012 \\ \text{ReplCost}_x + \Psi_x(\text{t-2012})(\text{ReplCost}_x),\ \text{if } t > 2012 \end{cases} \quad : \forall\ i,t,x \tag{9}$$

Equation 10 denotes status quo capital expenses (CAPEX) occurring in future years (t) when the age (Age_i) of the circuit exceeds the expected useful lifespan. All capital expenses incurred for each circuit (Length_i) are then discounted t-2012 years back to the present—every time a replacement occurs—using discount rate, r, and summed over the entire analysis period (2013–2050).

$$\text{CAPEX}_i^{\text{StatusQuo}} = \begin{cases} \displaystyle\sum_{t=2013}^{2050} \frac{\text{ReplCost}_{xt}(\text{Length}_i)}{(1+r)^{t\text{-}2012}},\ \text{if Age}_{it} = 1 \\ 0,\ \text{if Age}_{it} \neq 1 \end{cases} \quad : \forall\ i,t,x \tag{10}$$

Equation 11 describes how annual O&M expenses (OPEX) for each type of T&D line are assumed to be a fraction (Θ_x) of the overall replacement costs (ReplCost)—and that these O&M expenses increase at a constant amount each year as the circuit approaches its expected useful lifespan.[11]

[11] It is likely that actual infrastructure O&M expenses increase (decrease) over time in a non-linear fashion. Future research should be undertaken to determine a more appropriate functional form. For the purposes of this initial analysis, however, a linear increase is more accurate than the assumption that O&M expenditures are constant regardless of circuit age.

$$OPEX_{xt} = \begin{cases} \Theta_x (ReplCost_{xt}),\ \text{if } Age_{it} = 1 \text{ and } x = [1,2] \\ OPEX_{xt\text{-}1} + \Theta_x (ReplCost_{xt}),\ \text{if } Age_{it} > 1 \text{ and } x = [1,2] \\ \Theta_x (ReplCost_{xt}),\ \text{if } Age_{it} = 1 \text{ and } x = [3,4] \\ OPEX_{xt\text{-}1} + \Theta_x (ReplCost_{xt}),\ \text{if } Age_{it} > 1 \text{ and } x = [3,4] \end{cases} \quad : \forall\ i,t \tag{11}$$

Annual O&M expenses incurred for each circuit ($Length_i$) are then discounted back to the present using discount rate, r, and then summed for all future years in the analysis (see Equation 12).

$$OPEX_i^{StatusQuo} = \sum_{t=2013}^{2050} \frac{(OPEX_{xt})(Length_i)}{(1+r)^{t-2012}} \quad : \forall\ i,t \tag{12}$$

Total lifecycle costs, under the status quo, can then be estimated by summing both recurring capital and ongoing O&M expenditures for all circuits (see Equation 13).

$$LifecycleCost^{StatusQuo} = \sum_i CAPEX_i^{StatusQuo} + \sum_i OPEX_i^{StatusQuo} \quad : \forall\ i \tag{13}$$

Under the undergrounding alternative, however, the model replaces existing overhead infrastructure with underground infrastructure in the first retirement year. Equation 14 describes how the first retirement year is determined using the expected useful lifespan and age of circuit in 2012.

$$FirstRetire_i = Lifespan_x \text{-} Age2012_i + 2012 \quad : \forall\ i,x \tag{14}$$

Equation 15 describe how at a specific point in time ($FirstRetire_i$) and in all future retirement years, the overhead lines are replaced with underground lines that have a relatively shorter technical lifespan and higher capital costs (CAPEX).

$$\text{CAPEX}_i^{\text{Under}} = \begin{cases} \sum_{t=2013}^{2050} \frac{\text{ReplCost}_{(x+2)t}(\text{Length}_i)}{(1+r)^{t-2012}}, \text{if Age}_{it} = 1 \text{ and x=[1,2]} \\ \sum_{t=2013}^{2050} \frac{\text{ReplCost}_{xt}(\text{Length}_i)}{(1+r)^{t-2012}}, \text{if Age}_{it} = 1 \text{ and x=[3,4]} \\ 0, \text{if Age}_{it} \neq 1 \end{cases} \quad : \forall \text{ i,t}$$

(15)

For the undergrounding scenario and prior to the first retirement, annual overhead O&M expenses are estimated in the same fashion as described in Equation 11. However, after an overhead circuit is first converted to an underground circuit, then annual O&M expenses are re-estimated for the new underground line and these costs increase each year according to the amount specified in Equation 11. Equation 16, below, describes how circuit O&M costs reset as overhead lines are converted to underground lines.

$$\text{OPEX}_i^{\text{Under}} = \begin{cases} \sum_{t=2013}^{2050} \frac{(\text{OPEX}_{xt})(\text{Length}_i)}{(1+r)^{t-2012}}, \text{ if x=[3,4]} \\ \sum_{t=2013}^{2050} \frac{(\text{OPEX}_{xt})(\text{Length}_i)}{(1+r)^{t-2012}}, \text{ if t < FirstRetire}_i \text{ and x=[1,2]} \\ \sum_{t=2013}^{2050} \frac{(\text{OPEX}_{(x+2)t})(\text{Length}_i)}{(1+r)^{t-2012}}, \text{ if t } \geq \text{ FirstRetire}_i \text{ and x=[1,2]} \end{cases} \quad : \forall \text{ i,t}$$

(16)

Total lifecycle costs, under the undergrounding scenario, can then be estimated by summing both the recurring capital and ongoing O&M expenditures for all circuits (see Equation 17).

$$\text{LifecycleCost}^{\text{Under}} = \sum_i \text{CAPEX}_i^{\text{Under}} + \sum_i \text{OPEX}_i^{\text{Under}} \quad : \forall \text{ i} \qquad (17)$$

Equation 18 shows that future annual underground line mileage (Underground_t) can be determined based on the existing amount of underground line miles in 2012 ($\text{Underground}_{2012}$) and the ongoing conversion from overhead to underground T&D lines described above.

$$\text{Underground}_t = \begin{cases} \left(\text{Underground}_{2012}\right) + \sum_i \text{Length}_i \text{, if } t \geq \text{FirstRetire}_i \\ \left(\text{Underground}_{2012}\right) \text{, if } t < \text{FirstRetire}_i \end{cases} \quad : \forall \text{ i,t,x}$$

(18)

Finally, the net present value of costs (LifecycleCost) associated with the status quo case are subtracted from the undergrounding alternative to estimate the additional lifecycle costs due to undergrounding (see Equation 19).

$$\text{LifecycleCost}^{\text{Net}} = \text{LifecycleCost}^{\text{Under}} - \text{LifecycleCost}^{\text{StatusQuo}} \tag{19}$$

3.3 Avoided Costs from Less Frequent Outages

All residents and businesses living and operating, respectively, within the IOU service territories will avoid costs if undergrounding leads to less frequent power outages. The avoided costs from a more reliable electrical grid were derived by: (1) applying an econometric model developed by Larsen et al. (2015) to estimate the total number of outages—under the status quo—from now until 2050; (2) estimating 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; (3) assigning a dollar value for the total number of annual customer-outages for both alternatives; and (4) subtracting the outage-related costs for the undergrounding alternative from the outage costs for the status quo to determine the dollar value of reduced outages.

Larsen et al. (2015) develop an electric utility reliability model that correlates annual measures of weather (heating degree-days, cooling degree-days, lightning strikes, wind speed, and precipitation), utility T&D expenditures, delivered electricity, presence of outage management systems, number of customers per line mile, and share of underground miles to the frequency of power outages ($\text{Outages}_t^{\text{StatusQuo}}$) across the United States (see Equation 20).[12]

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[12] Electric utility and reporting year are represented by subscript i and t, respectively. Please see the Technical Appendix for the values of the coefficients used in this analysis.

$$\text{Outages}_t^{\text{StatusQuo}} =$$

$$\exp\begin{pmatrix}\beta_1 + \beta_2\text{Sales} + \beta_3\text{Expenditures} + \beta_4\text{PostOMS} + \beta_5\text{OMS} + \beta_6\text{Cold} + \beta_7\text{Warm} \\ +\beta_8\text{Lightning} + \beta_9\text{Windy} + \beta_{10}\text{Windy}^2 + \beta_{11}\text{Wet} + \beta_{12}\text{Dry} + \beta_{13}\text{Year} \\ +\beta_{14}\text{Customers} + \beta_{15}\text{Underground}\end{pmatrix}$$

(20)

The model coefficients (and intercept) from Larsen et al. (2015) were used along with average values of historical weather and other model inputs that are relevant for Texas (see Technical Appendix) to estimate the future number of outages for Texas IOUs for the status quo.

Next, the total number of outages were estimated—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. Again, the coefficients and intercept were used from Larsen et al. (2015). However, instead of using a fixed ~20% value for the share of T&D miles underground, the share of underground miles was increased based on annual overhead-to-underground conversion decisions from the lifecycle replacement analysis. In addition, a weather impact mitigation factor, phi, was used to decrease the impact of the weather on utility reliability—as the share of underground miles (Underground) increased. Equation 21 represents the weather impact mitigation factor.

$$\phi_t = 1 - (\text{Underground}_t - \text{Underground}_{2012}) \qquad (21)$$

Equation 22 depicts how the frequency of power outages was re-estimated ($\text{Outages}_t^{\text{Under}}$) using both the weather impact mitigation factor and the increasing share of underground miles.

$$\text{Outages}_t^{\text{Under}} =$$

$$\exp\begin{pmatrix}\beta_1 + \beta_2\text{Sales} + \beta_3\text{Expenditures} + \beta_4\text{PostOMS} + \beta_5\text{OMS} \\ +\phi_t\left(\beta_6\text{Cold} + \beta_7\text{Warm} + \beta_8\text{Lightning} + \beta_9\text{Windy} + \beta_{10}\text{Windy}^2 + \beta_{11}\text{Wet} + \beta_{12}\text{Dry}\right) \\ +\beta_{13}\text{Year} + \beta_{14}\text{Customers} + \beta_{15}\text{Underground}\end{pmatrix}$$

(22)

The total value of lost load under the status quo (Equation 23) and undergrounding (Equation 24) alternative can be estimated using (1) the number of outages from Equations 20 and 22, respectively; (2) the number of customers (Customers) for each class of service (i.e., commercial and industrial, residential, other), *c*; and (3) and assumptions about the lost economic value, by customer class, for each power outage (VLL).

$$\mathrm{VLL}^{\mathrm{StatusQuo}} = \sum_{t=2013}^{2050} \frac{\left(\sum_{c=1}^{3} \mathrm{Outages}_t^{\mathrm{StatusQuo}} (\mathrm{Customers}_c)(\mathrm{VLL}_c)\right)}{(1+r)^{t\text{-}2012}} \tag{23}$$

Sullivan et al. (2010) report a range of values of lost load per outage—by duration—for residential, commercial and industrial customers. For the base case analysis, it is assumed that the value of lost load per customer is based on a 30-minute power outage and that other and small commercial and industrial customers have equivalent VLLs.

$$\mathrm{VLL}^{\mathrm{Under}} = \sum_{t=2013}^{2050} \frac{\left(\sum_{c=1}^{3} \mathrm{Outages}_t^{\mathrm{Under}} (\mathrm{Customers}_c)(\mathrm{VLL}_c)\right)}{(1+r)^{t\text{-}2012}} \tag{24}$$

Finally, the benefits of avoided outages were calculated by subtracting the status quo total value of lost load ($\mathrm{VLL}^{\mathrm{StatusQuo}}$) from the total value of lost load from the undergrounding alternative ($\mathrm{VLL}^{\mathrm{Under}}$) (Equation 25).

$$\mathrm{VLL}^{\mathrm{Avoided}} = \mathrm{VLL}^{\mathrm{StatusQuo}} - \mathrm{VLL}^{\mathrm{Under}} \tag{25}$$

3.4 Avoided Aesthetic Costs as a Proxy for Property Value Improvements

For this analysis, it is assumed that property owners will receive no aesthetic benefit from undergrounding *distribution* lines, because it is likely that poles with television cable and internet cables will continue to stay in place for the foreseeable future (Most and Weissman 2012). However, as discussed earlier, hedonic studies (Des Rosiers 2005; Sims and Dent 2002; Headwaters Economics 2012; Navrud et al. 2008) have shown that the presence of overhead high-voltage transmission lines negatively affect the value of real estate (e.g., ~ -5% to -20%). It is assumed that avoided aesthetic costs serve as a proxy for improved property values. Calculating the net aesthetic benefit of undergrounding these transmission lines involves the following: (1) estimating the number of residential, commercial and industrial, and other properties within an "overhead transmission corridor" (e.g., 300 feet on either side of overhead transmission line or 600 feet wide); (2) multiplying the number of affected properties against the median real estate value (PropertyValue) for each property class and lost property value (PriceImpact) associated with overhead high-voltage transmission lines (e.g., 12.5%, which is the average of the high and low values found in Des Rosiers (2002) is used for the base case); and (3) discounting the stream of avoided aesthetic costs back to the present using a 10% discount rate (see Equation 26).

$$\text{Aesthetic}^{\text{Under}} = \sum_{t=2013}^{2050} \frac{\left(\frac{\left(\frac{\text{Corridor}}{5280}\right)\left(\text{Underground}_t - \text{Underground}_{t-1}\right)}{\text{ServiceArea}} \right)(\text{Customers}_c)(\text{PropertyValue}_c)(\text{PriceImpact})}{(1+r)^{t-2012}} \tag{26}$$

3.5 Ecosystem-related Restoration Costs

It is assumed that habitat restoration activities took place when the existing overhead and underground lines were sited, but that fewer restoration activities will need to take place as new lines are added and/or converted to underground infrastructure. It is also assumed that undergrounding T&D lines will affect a larger surface area than overhead lines (Public Service Commission of Wisconsin 2013). The monetization of ecosystem restoration costs involved (1) estimating the number of acres affected by T&D line growth in the future (using development corridor width and total line miles); (2) multiplying total T&D line corridor acreage against a conservation easement price; and (3) discounting this cost back to the present.

Equation 27 describes initial assumptions about the width, in feet, of the T&D line corridor for the overhead transmission (x=1) and distribution (x=2) lines and underground transmission (x=3) and distribution (x=4) lines.

$$\text{Corridor}^{\text{Eco}} = \begin{cases} 60 : x = [1,2] \\ 120 : x = [3,4] \end{cases} \tag{27}$$

The total ecosystem restoration cost of the status quo alternative was calculated by multiplying the additional overhead line miles (built after 2012) against the relevant corridor width ($\text{Corridor}^{\text{Eco}}$), converting square miles to acres, and multiplying the impacted ecosystem acreage against the per-acre price of a conservation easement (EasementValue) in year t (see Equation 28).

$$\text{Restoration}^{\text{StatusQuo}} =$$

$$\sum_{t=2013}^{2050} \frac{\left(\sum_{x=1}^{2}\sum_{i}\text{Length}_{it} - \sum_{x=1}^{2}\sum_{i}\text{Length}_{it\text{-}1}\right)\left(\frac{\text{Corridor}^{\text{Eco}}(640)}{5280}\right)(\text{EasementValue})}{(1+r)^{t\text{-}2012}} \tag{28}$$

The total ecosystem restoration cost of the undergrounding alternative was calculated by multiplying the additional underground line miles (built after 2012) against the relevant corridor width ($\text{Corridor}^{\text{Eco}}$), converting square miles to acres, and multiplying the impacted ecosystem acreage against the per-acre price of a conservation easement in year t (see Equation 29).

$$\text{Restoration}^{\text{Under}} =$$

$$\sum_{t=2013}^{2050} \frac{\left(\text{Underground}_{t} - \text{Underground}_{t\text{-}1}\right)\left(\frac{\text{Corridor}^{\text{Eco}}(640)}{5280}\right)(\text{EasementValue})}{(1+r)^{t\text{-}2012}} \tag{29}$$

It is assumed in this case study that an unlimited amount of Texas conservation easements can be purchased for $3,000/acre in any year (The Nature Conservancy 2014) and that future easement purchases were discounted back to the present using a 10% discount rate. It follows that the additional (net) restoration costs—due to undergrounding—can be calculated by subtracting the status quo restoration costs from the undergrounding alternative restoration costs (see Equation 30).

$$\text{Restoration}^{\text{Net}} = \text{Restoration}^{\text{Under}} - \text{Restoration}^{\text{StatusQuo}} \tag{30}$$

3.6 Construction-related Morbidity and Mortality Costs

It is unfortunate, but likely that replacing a large amount of overhead infrastructure with underground infrastructure will lead to relative increases in risk to utility operational staff working in the field. For that reason, it is assumed that health and safety costs will increase—above levels observed with the status quo—as the share of underground lines increases. Quantifying the additional costs associated with increases in worker morbidity and mortality involved a number of steps.

First, publicly-accessible information was used from the utilities to estimate the total number of employees working for the utilities represented in this study. Next, information was collected on the existing incidence rates and costs of relevant injuries (e.g., electrocution, broken bones, burns, sprains, mass trauma) for electric utility workers from the U.S. Occupational Safety and Health Administration (U.S. Department of Labor 2014). In addition, information is collected on existing fatality rates for the electric utility sector from U.S. Bureau of Labor Statistics (2014) and the value of a statistical life ($6.9 million) from a recent document published by the Executive Office of the President (2013b). The following equations describe how non-fatal costs (Equation 31) and fatality-related economic losses (Equation 32) were calculated by multiplying the corresponding incidence rates by the number of IOU employees (Employees), a randomly determined annual injury cost (InjuryCost), and the value of statistical life; and discounting the future annual morbidity and mortality costs back to the present using an appropriate discount rate.

$$\text{NonFatal}^{\text{StatusQuo}} =$$

$$\sum_{t=2013}^{2050} \frac{\left((\text{NFIR}) \left(\frac{\text{Employees}}{100000} \right) (\text{InjuryCost}) \right)}{\left(1+\text{r}\right)^{\text{t-2012}}} \tag{31}$$

Where NFIR and FIR represents non-fatality and fatality incidence rates, respectively; *Employees* are the total number of employees working for the Texas IOUs, InjuryCost is the total direct and indirect cost of an injury that is likely to occur for workers in the electric utility sector; and VSL is the value of a statistical life.

$$\mathrm{Fatal}^{\mathrm{StatusQuo}} =$$

$$\sum_{t=2013}^{2050} \frac{\left((\mathrm{FIR}) \left(\frac{\mathrm{Employees}}{100000} \right) (\mathrm{VSL}) \right)}{(1+\mathrm{r})^{\mathrm{t-2012}}} \tag{32}$$

The fatal and non-fatal incidence rates were increased proportionally as the share of underground line miles increases each year (see Equation 33).

$$\psi_t = \left(\frac{\mathrm{Underground}_{\mathrm{t}}}{\mathrm{Underground}_{\mathrm{t-1}}} \right) \tag{33}$$

Next, the increased incidence rates by the number of employees, injury costs, and value of statistical life for the undergrounding alternative; and discounted the future annual morbidity and mortality costs back to the present using an appropriate discount rate (see Equations 34 and 35).

$$\mathrm{NonFatal}^{\mathrm{Under}} =$$

$$\sum_{t=2013}^{2050} \frac{\left((\psi_t)(\mathrm{NFIR}) \left(\frac{\mathrm{Employees}}{100000} \right) (\mathrm{InjuryCost}) \right)}{(1+\mathrm{r})^{\mathrm{t-2012}}} \tag{34}$$

$$\mathrm{Fatal}^{\mathrm{Under}} =$$

$$\sum_{t=2013}^{2050} \frac{\left((\psi_t)(\mathrm{FIR}) \left(\frac{\mathrm{Employees}}{100000} \right) (\mathrm{VSL}) \right)}{(1+\mathrm{r})^{\mathrm{t-2012}}} \tag{35}$$

Finally, the NPV of status quo fatal and non-fatal costs is subtracted from the NPV of fatal and non-fatal costs (undergrounding alternative) to determine the NPV of morbidity and mortality costs (HealthSafety) due to undergrounding (see Equation 36).

$$\mathrm{HealthSafety}^{\mathrm{Net}} =$$

$$\left(\mathrm{NonFatal}^{\mathrm{Under}} + \mathrm{Fatal}^{\mathrm{Under}}\right) - \left(\mathrm{NonFatal}^{\mathrm{StatusQuo}} + \mathrm{Fatal}^{\mathrm{StatusQuo}}\right) \tag{36}$$

3.7 Sensitivity Analysis

A sensitivity analysis was conducted by varying several of the key inputs to this cost-benefit analysis—independently and together—including the: (1) replacement cost of undergrounding lines; (2) impact of undergrounding on reliability; (3) purchase price of conservation easements; (4) increased chance of construction-related accidents and fatalities; (5) discount rate; (6) alternative lost real estate value assumptions; (7) alternative lifespan assumptions for overhead infrastructure; (8) assumptions related to the value of mortality and morbidity; (9) alternative value of lost load assumptions; (10) the number of customers per line mile; and (11) O&M costs of undergrounding lines. Table 2 shows which sensitivity analyses apply to each of the selected impact categories.

Table 2. Sensitivity analyses and impact categories

		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	$26,131.6	$130,658	$235,184.4				*	

		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)**
	costs and VSL ($ per accident/$ per life)	$1,380,000 (VSL)	$6,900,000 (VSL)	$12,420,000 (VSL)					
7	Alternative conservation easement prices ($/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.)	*				

4. Results and Discussion

4.1 Estimated Costs

Figure 4 shows the impact of varying the assumed lifespan of overhead T&D lines. Not surprisingly, as the assumed lifespan of overhead lines is decreased from seventy-five to sixty to forty-five years, the lifecycle algorithm replaces those overhead lines with underground lines earlier in time—leading to a larger share of underground line miles by 2050. For example, the entire Texas IOU T&D system could be 50% underground by 2028 if the lifespan of existing overhead lines is assumed to be forty-five years instead of sixty years. The share of underground line miles has important economic implications throughout this analysis. Accordingly, a sensitivity analysis is conducted on the assumed lifespan of existing overhead T&D infrastructure.

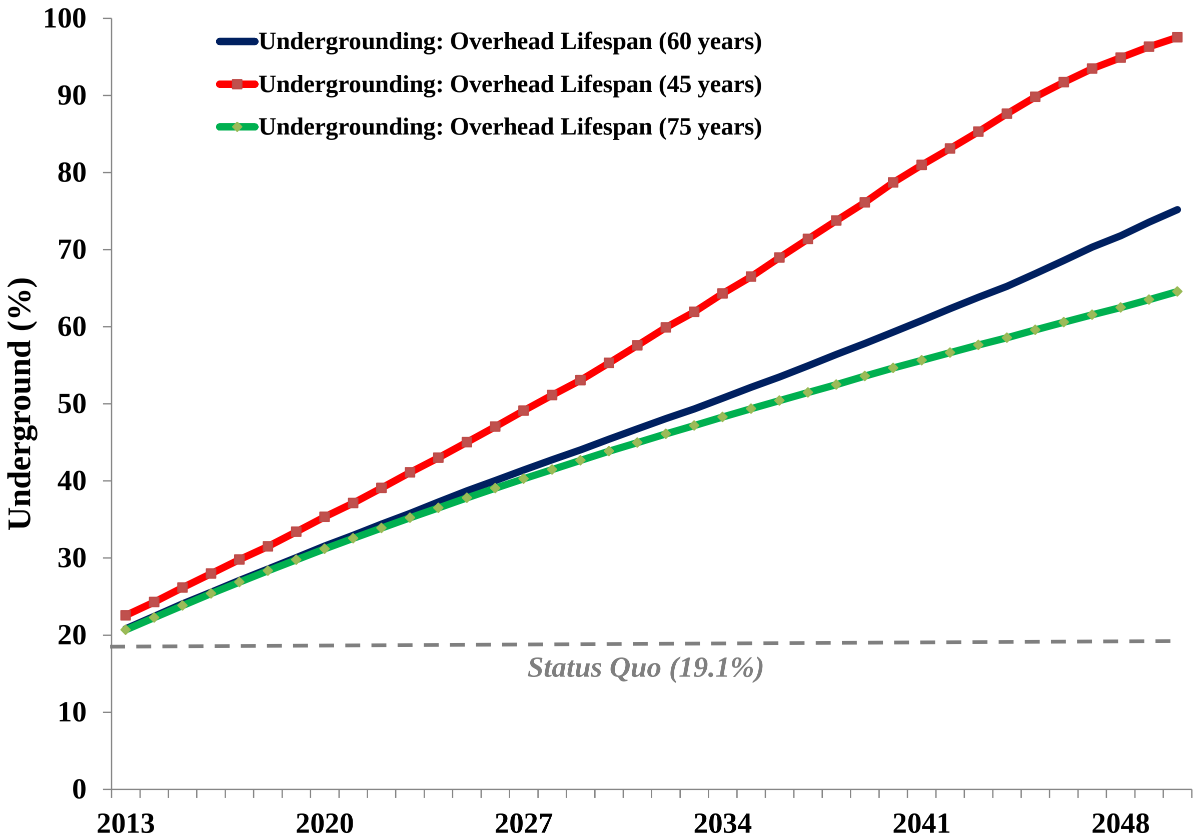

Figure 4. Share of underground line miles using alternative useful lifespans of overhead T&D lines

Figure 5 shows that the lifecycle replacement costs ranged from ~$26.0 billion (status quo) to $52.3 billion (undergrounding). Net increased NPV replacement costs were ~$26.3 billion. The net present value of ecosystem restoration costs were ~$1.0 billion for the status quo and ~$2.8 billion for the undergrounding alternative. Additional ecosystem restoration costs due to undergrounding were ~$1.8 billion. Base case health and safety costs were ~$313 million and $560 million for the status quo and undergrounding alternative, respectively. It follows that additional health and safety costs due to undergrounding are ~$245 million.

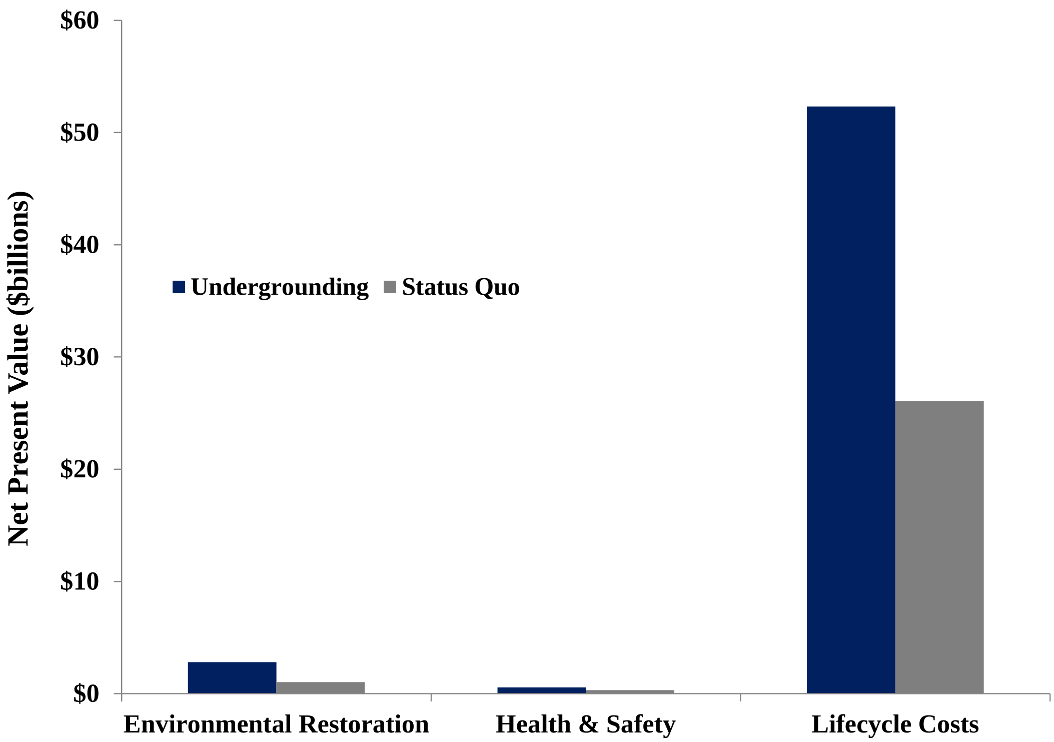

Figure 5. Net present value of costs for status quo and undergrounding alternative

4.2 Estimated Benefits

In the previous section, it was demonstrated that as the share of underground line miles increases, customers will experience less frequent power outages over time—relative to the status quo (see Figure 6). It is important to note that outages continue to increase under both the status quo and undergrounding scenarios—as shown in Figure 6. This finding is a result of the positive coefficient for the YEAR coefficient (i.e., a positive time trend indicates that the frequency of outages is increasing over time) as reported by Larsen et al. (2015) and in Table A-7 of the Technical Appendix.

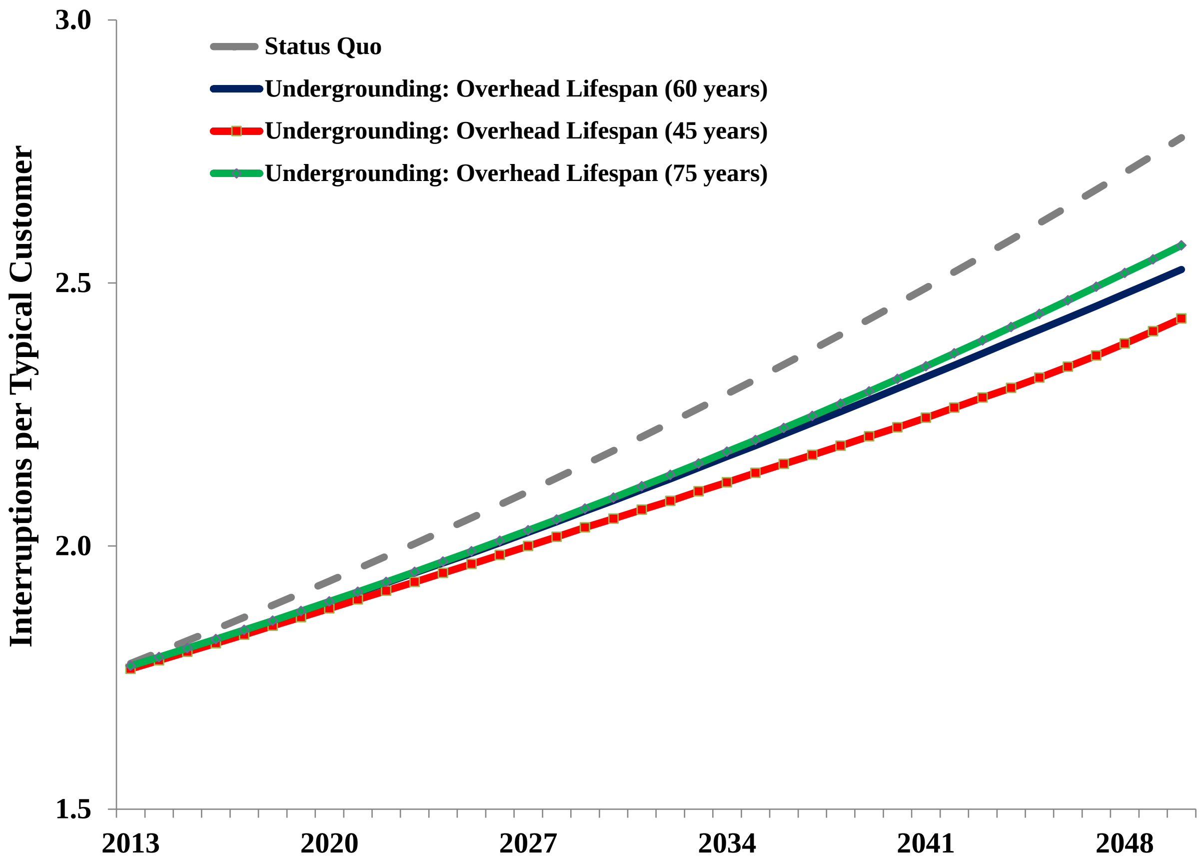

Figure 6. Typical number of interruptions per customer for status quo and alternative assumptions about useful lifespan of overhead T&D lines

Figure 7 shows the interruption costs for the status quo (~$188 billion) and undergrounding alternative (~$183 billion). Accordingly, the avoided interruption costs due to undergrounding is estimated at approximately $5.8 billion. Figure 7 also shows that the total avoided aesthetic costs for the status quo is estimated at $10.5 billion with the avoided aesthetic costs increasing to $12.0 billion for the undergrounding alternative. Net increased avoided aesthetic costs, which is a proxy for the property value benefits of undergrounding, is estimated at ~$2 billion.

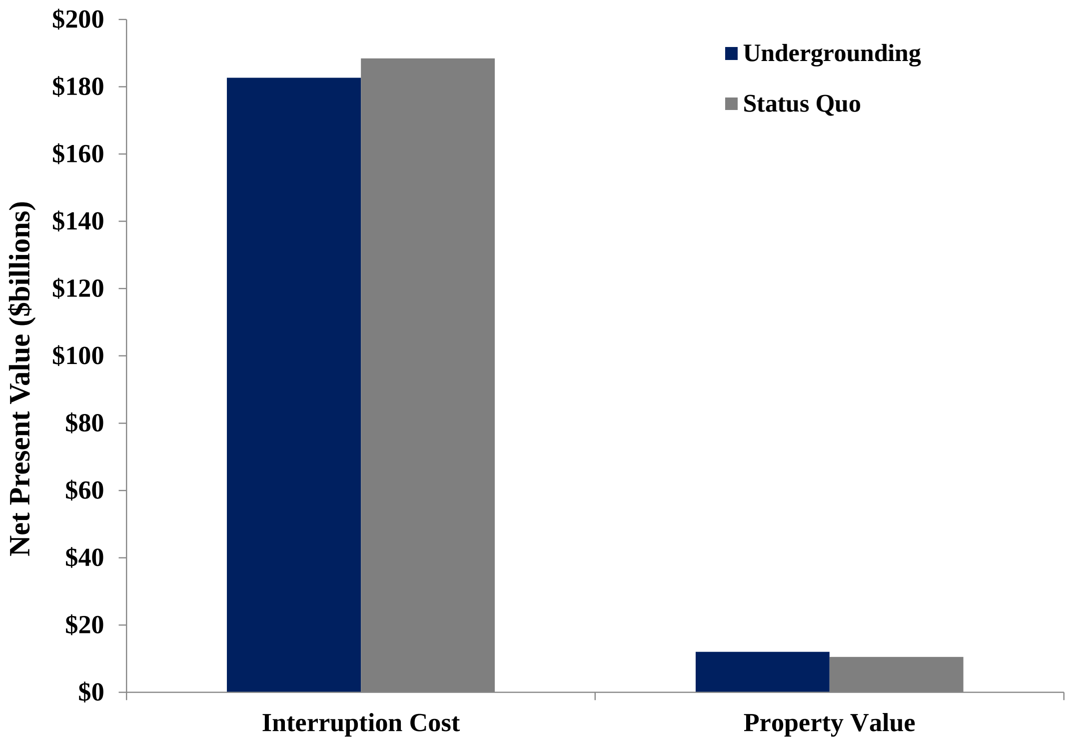

Figure 7. Net present value of benefits for status quo and undergrounding alternative

Figure 8 shows a breakdown of the net benefits of avoided outage costs by the three customer classes. Commercial/industrial customers are projected to receive the largest share of net benefits ($5.7 billion) primarily due to the relatively higher value of lost load assumption for this customer class when compared to the other customer classes.

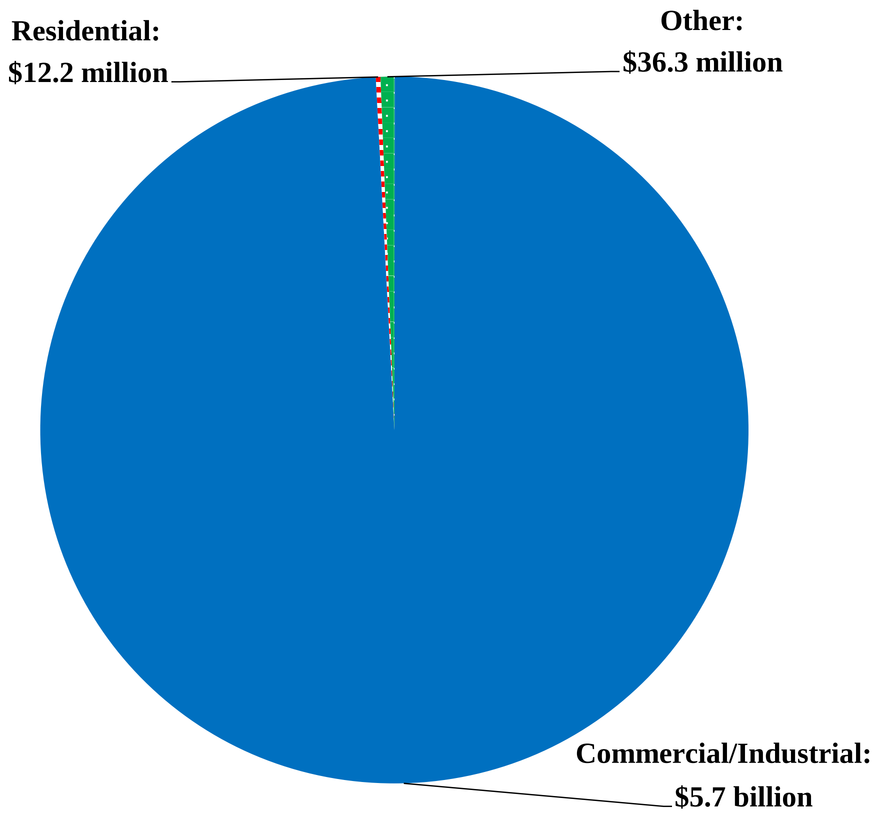

Figure 8. Net present value of net avoided interruption costs by customer type

Figure 9 shows a breakdown of the net increase in avoided aesthetic costs by the three customer classes. Commercial/industrial and residential customers are projected to benefit from an approximately equal share of the avoided aesthetic cost gains.

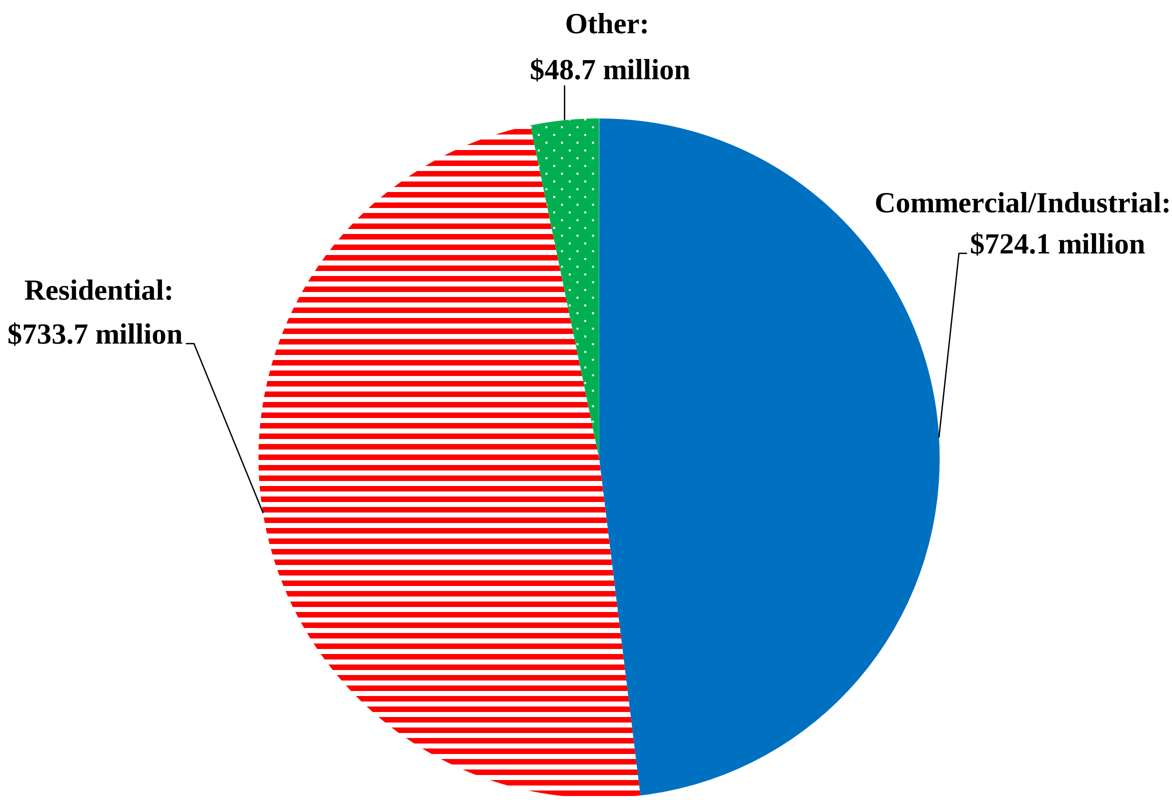

Figure 9. Net present value of *net* avoided aesthetic costs by customer type

4.3 Net Social Benefit and Sensitivity Analysis

Under the base case, the net costs from undergrounding are estimated at ~$28.3 billion with net benefits of ~$7.3 billion (see Table 3). It follows that the base case net social loss from undergrounding all Texas IOU T&D lines is ~$21 billion, which is equivalent to a 0.3 benefit-cost ratio.

Table 3. Summary of base case costs and benefits

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**

Figure 10 is a tornado diagram created by varying each of the eleven key input assumptions, separately, to evaluate the overall effect on the total net benefit calculation.[13] This type of sensitivity analysis shows that the net benefit (loss) calculation is most sensitive to the choice of (1) discount rates; (2) replacement cost of undergrounding lines; (3) overhead T&D line lifespan; (4) value of lost load; and (5) customers per line mile. For example, the minimum costs for replacing underground T&D lines leads to net benefits of ~$5 billion whereas assuming the maximum replacement cost yields net losses of ~$47 billion—all else being equal.

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 in Table 2— *simultaneously*. The resulting distributions, which are based on repeated sampling (n=500), show the full range of net benefits possible if all key parameters vary simultaneously and independently of one another. Figure 11 shows the likelihood of total net losses for an assumed overhead T&D line lifespan of forty-five years (red), sixty years (dark blue), and seventy-five years (green). As discussed earlier, if overhead lifespans are assumed to be shorter, a larger share of lines are undergrounded—with corresponding relative increases in net losses. The results of the Monte-Carlo simulations show average net losses of ~$21.6 billion. Interestingly, varying all of the key parameters simultaneously leads to consistently negative average net losses. In addition, net losses may be the highest in places where the typical lifespan of overhead lines is

[13] The results were generated by running the individual parameter minimum and maximum values as shown in Table 2.

the shortest. In this case, the net present value (NPV) lifecycle costs of replacing the shorter lifespan overhead lines with underground lines—in the near term—far exceed the NPV lifecycle costs of replacing longer lifespan overhead lines many decades into the future. For this reason, the net losses are lower under the seventy-five-year lifespan sensitivity assumptions.

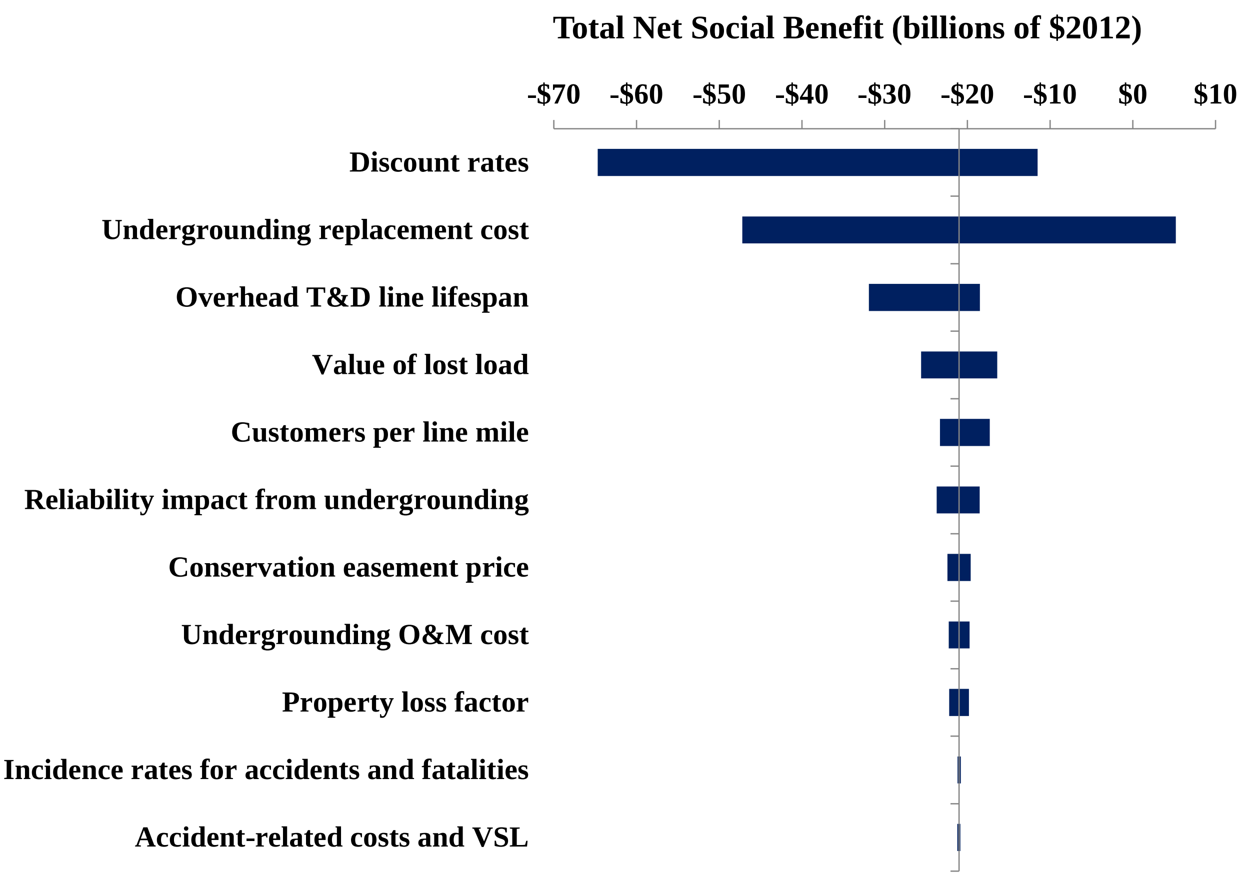

Figure 10. Sensitivity analysis of net social benefit (loss) using alternative model parameters

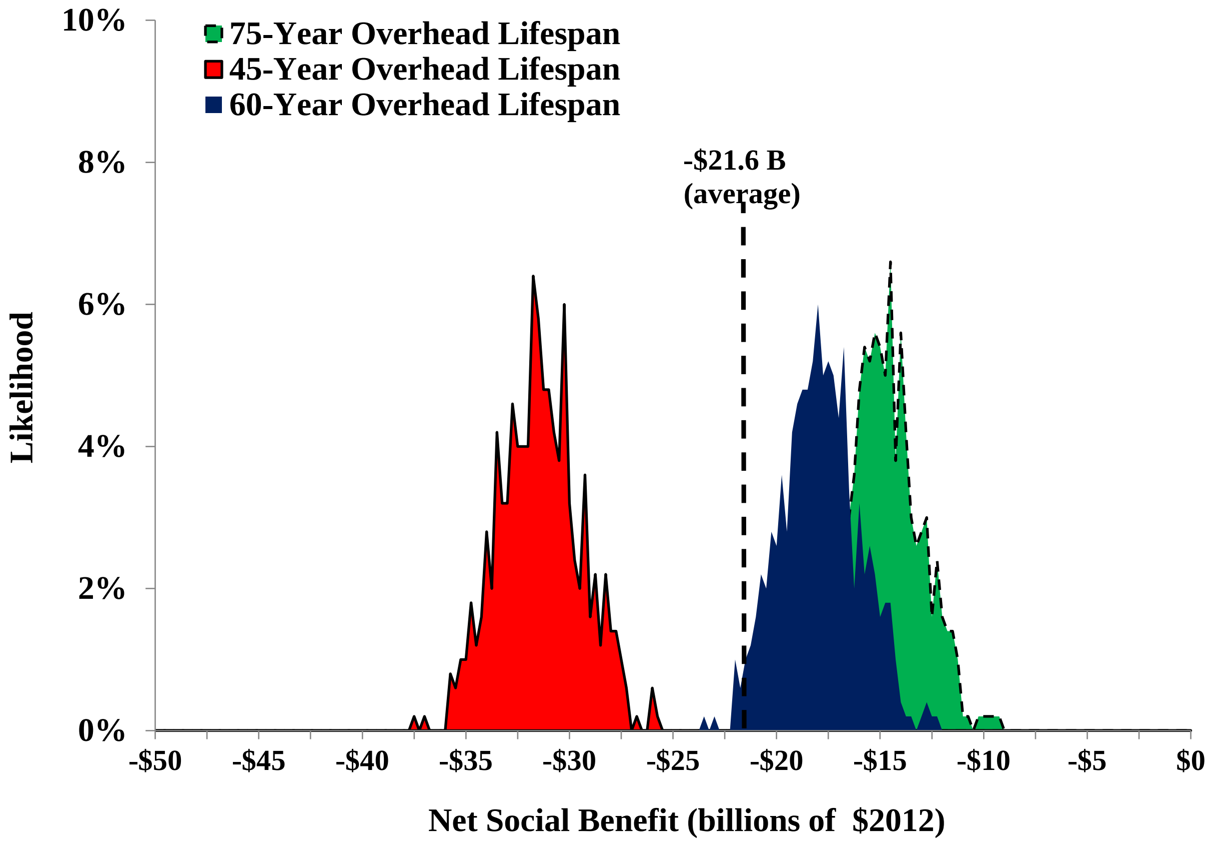

Figure 11. Monte-Carlo simulation of net social loss for 45/60/75-year lifespan for overhead T&D lines (billions of $2012)

4.4 Minimum Conditions Necessary for Positive Net Social Benefits

To date, widespread undergrounding initiatives have been most prevalent in urban areas including Washington D.C., San Diego, New York City, and London (Washington D.C. Power Line Undergrounding Task Force 2014; City Council of San Diego 2002; New York City Office of Long-Term Planning and Sustainability 2013; National Grid-UK 2016). It is possible that there may be localized net benefits in places where (1) there are a large number of customers per line mile (i.e., urban areas)—thus allowing IOUs to achieve economies of scale during the installation of underground lines; and (2) undergrounding is expected to lead to substantial reliability improvements in urban areas vulnerable to frequent and intense storms.

This subsection evaluates the possibility that strategically-focusing undergrounding efforts on urban areas within service territories could lead to net benefits.

Method and Key Assumptions

The goal of this analysis is to identify the minimum conditions that would need to be met in order for a targeted undergrounding initiative to have a near-zero net benefit (i.e., benefit-cost ratio equal to one). To achieve this, the undergrounding model was solved through a backward induction technique where:

- only T&D lines passing within one mile of an urban area are considered in the analysis
- the reliability impact from undergrounding falls within the range of the base case and maximum values reported in Table 2
- the right-of-way (i.e., easement area) is assumed to be larger for overhead lines than underground lines
- the initial underground T&D line capital costs vary within the range of the minimum and base case values (see Table 2) and in subsequent years are decreased until the resulting benefit-cost ratio is approximately equal to one.

These conditions and the assumptions used in this analysis are described in greater detail below.

Target urban areas within service territories

First, the extent of overhead and underground T&D line miles was reduced to reflect the subset of lines located near urban areas. Table 4 shows the assumed line miles and number of customers from the original, unrestricted analysis (rural and urban) and the restricted analysis (urban only) described in this subsection. As shown in Table 4, the customers per line mile more than doubles when only urban areas are considered. In addition to justifying undergrounding cost economies-of-scale (see below), customers per line is an explanatory variable in the model component used to project future outages (see section 3.4.2)—and the associated benefits from reductions in outages dues to undergrounding. It is assumed that the number of customers per line mile randomly varies from 63.5 (see Table 2) to 135 (the maximum value reported in Table 2)[14].

Table 4. Summary of Texas IOU line mileage and number of customers

[14] Figure A-1 in the technical appendix contains a map depicting the location of all overhead transmission lines that pass within one mile of a designated urban area (ABB-Ventyx 2015). It is also shown that there have been a significant number of major storms impacting urban areas across the Texas IOU service territories, including hurricanes (see Figure A-2).

Overhead or underground	Type	Urban + Rural Line Miles (Brown 2009)	Urban Line Miles
Overhead	Distribution	165,158	75,250 [a]
Overhead	Transmission	33,060	15,063 [b]
Underground	Distribution	46,669	2,881 [a]
Underground	Transmission	81	5 [b]
Total line mileage:		**244,968**	**93,199**
Number of customers:		**6,983,069**	**5,914,659** [c]
Customers per line mile:		**28.5**	**63.5**

Notes:
[a] Author estimates based on extrapolation using Brown (2009) and ABB-Ventyx (2015) sources.
[b] ABB-Ventyx (2015)
[c] Author estimated by multiplying Census (2015) share of Texas residents living in urban areas (84.7%) against estimate of all Texas IOU customers from Brown (2009).

Figure 12 shows that—depending on the assumed lifespan of overhead lines—the total Texas IOU line mileage converted to underground ranges from 40-55% by 2050. For comparison, undergrounding all rural and urban lines at the end of their useful lifespan resulted in 65-98% of the combined service territories being underground by 2050 (see Figure 4).

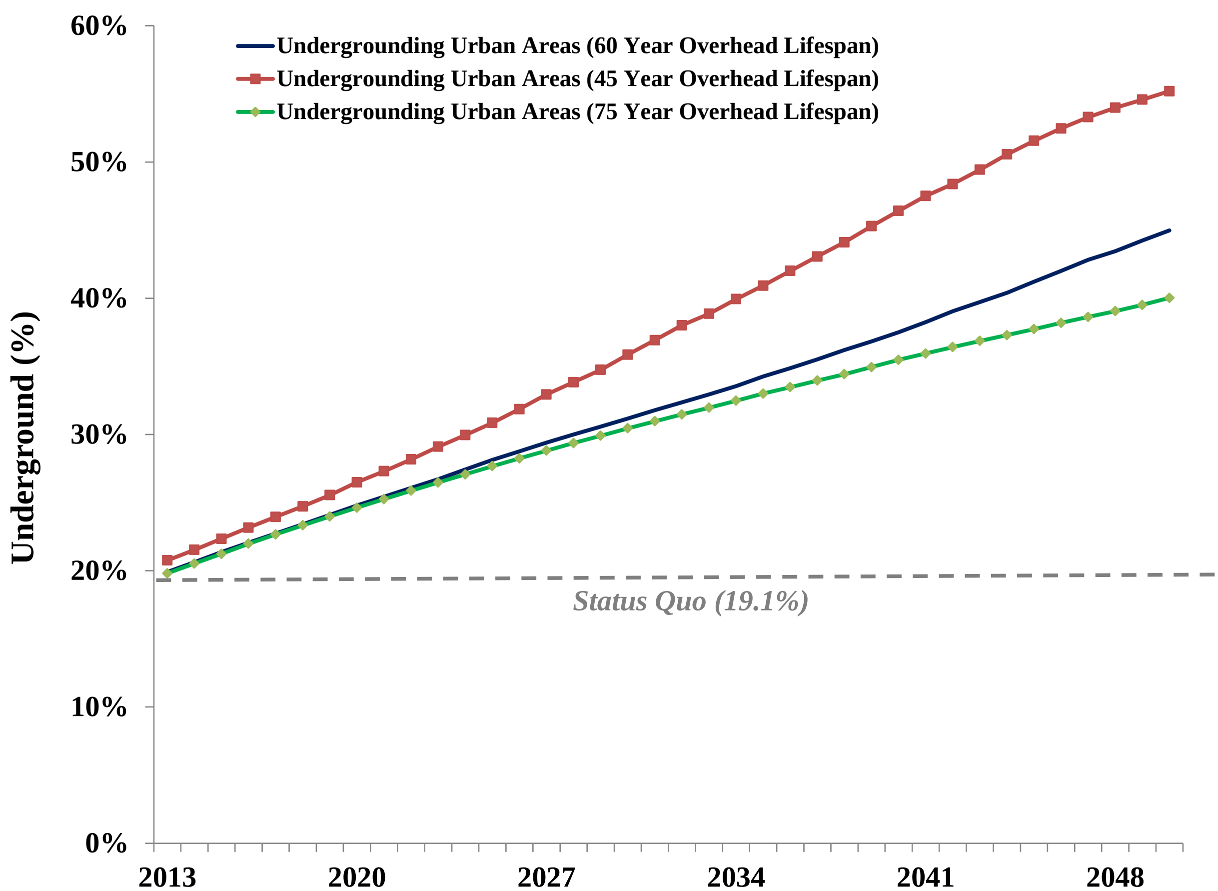

Figure 12. Share of underground line miles using alternative useful lifespans of overhead T&D lines

Power system reliability improvements

Next, it was shown in previous sections that power systems with a larger share of underground lines miles typically have higher levels of reliability. For this reason, the reliability impact from undergrounding is assumed to randomly vary within the range of the base case (-0.001) and maximum values (-0.0018) as reported in Table 2.

Higher ecosystem restoration costs for new overhead lines

The Chief Executive Officer of the Cordova (Alaska) Electric Cooperative, stated that the right-of-way for underground lines is smaller relative to overhead distribution corridors (Larsen 2016). Accordingly, the model was reconfigured by assuming that the typical widths of an underground and overhead right-of-way are 60 feet and 180 feet, respectively. This change implies that newly-sited overhead lines will have higher ecosystem restoration costs when compared to new underground lines. The overall effect is an avoided ecosystem restoration cost due to a larger share of underground lines.

Decreasing capital costs for underground lines

Finally, it is assumed that a strategic initiative to underground all urban, overhead T&D lines at the end of their existing useful lifespan can be achieved at a lower installation cost when compared to the unrestricted analysis assumptions introduced earlier. Urban areas, which have high customer population densities, will allow IOUs to achieve economies of scale. In many cities, there are existing and extensive underground rights-of-way, because of the placement of fiber optic lines and other telecommunications and public utility infrastructure (e.g., water/sewer corridors). This cost advantage—along with the ability of IOU workers to underground large expanses of lines within a small geographic area—are reasons why underground-overhead installation cost parity could be achieved in the not-so-distant future. For this analysis, it is assumed that the initial underground T&D line capital costs randomly vary within the range of the minimum and base case values (see Table 2) and are decreased linearly by 1.75% per year in each subsequent year.

Compared to the unrestricted analysis (i.e., entire IOU service territories undergrounded), the restricted analysis (i.e., only urban areas within IOU service territories) assumes that there are (1) larger improvements in reliability due to undergrounding near storm pathways, (2) capital cost reductions for underground T&D lines initially and in subsequent years; (3) larger ecosystem restoration costs (i.e., wider right-of-way) for overhead T&D lines; and (4) a higher number of customers per square mile. This model configuration represents the minimum conditions necessary to achieve average net social benefits (see Table 5 and Figure 13).

Table 5. Comparison of unrestricted (urban and rural) and restricted Monte-carlo analyses

Results	Unrestricted Analysis (Rural + Urban)	Restricted Analysis (Urban)
Average net social benefit for 45/60/75 year overhead lifespans	-$21.6 billion	$0.05 billion
Average benefit-cost ratio for 45/60/75 year overhead lifespans	0.3	1.0
Average % share of line miles underground by 2050 for 45/60/75 year overhead lifespans	79%	47%

If only urban areas are considered, then the percentage share of Texas IOU T&D line miles underground by 2050 drops from 79% to 47% (see Table 5). In other words, Texas IOUs could satisfy a social benefit-cost test if about half of their T&D line miles were underground by the middle of this century.

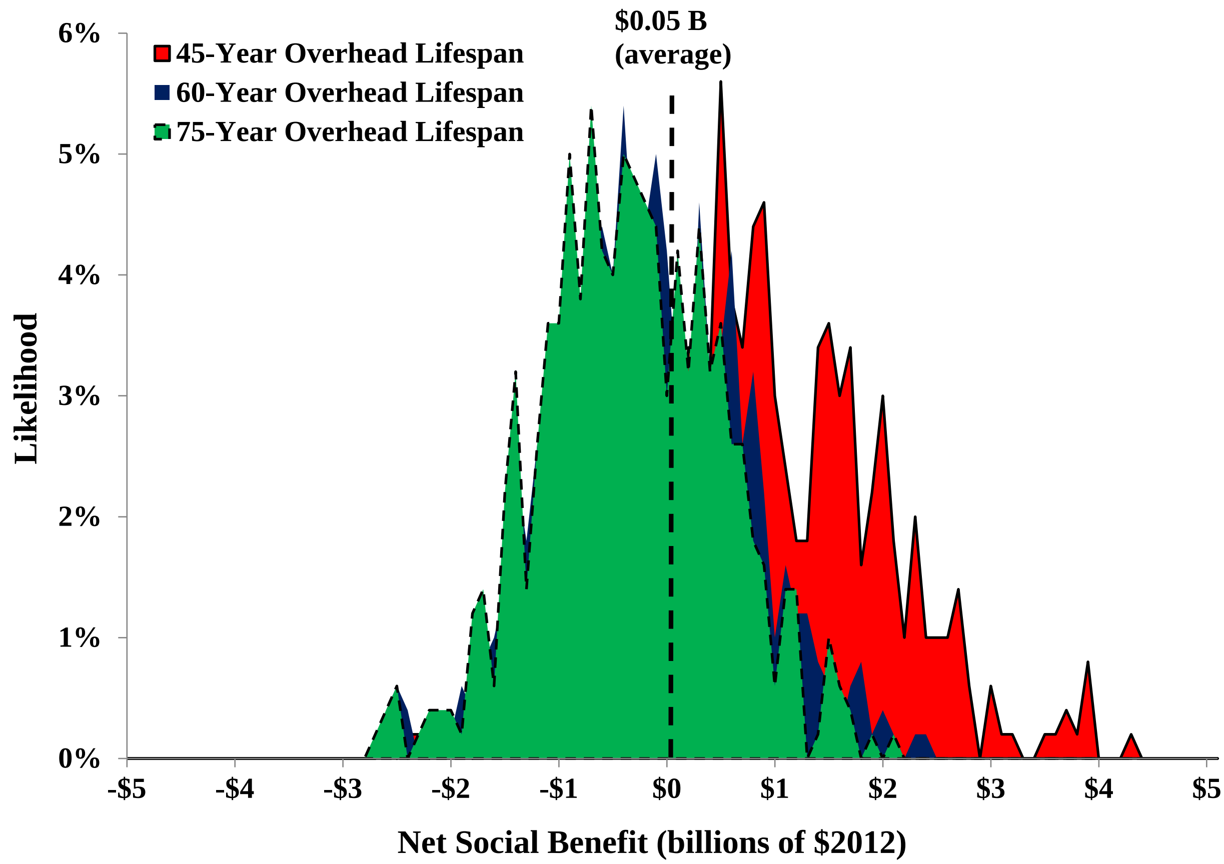

Figure 13. Monte Carlo simulation of net social benefit/loss for 45/60/75-year lifespan for overhead T&D lines (billions of $2012)

5. Conclusion

A general policy that mandates electric utilities to underground line infrastructure had a base case net social loss of ~$21 billion through 2050 (or a 0.3 benefit-cost ratio). Varying all of the key parameters simultaneously leads to aggregate net social losses of ~$21.6 billion—on average. The model results are most sensitive to the choice of (1) discount rates; (2) replacement cost of undergrounding lines; (3) overhead T&D line lifespan; (4) value of lost load; and (5) customers per line mile. 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. However, a subsequent configuration of the model found that a policy specifically targeting urban areas could be cost-effective if a number of key criteria are met. Policymakers should consider requiring that T&D lines be undergrounded in places where most of the following conditions are present:

- there are a large number of customers per line mile (e.g., greater than forty 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 T&D line utility easements (i.e., rights-of-way) are larger than underground T&D utility easements

However, there are limitations to this analysis—and a number of possibilities for improvement in the future. First, it is assumed that the number of utility employees, real estate prices, and conservation easement prices are fixed at current levels. It is likely that these specific assumptions will increase over time, which could affect the benefit-cost ratio. It is also possible that a national model of electric utility reliability (Eto et al. 2012; Larsen et al. 2015) may not be appropriate for regional or local analyses. More research is needed to explore the factors that affect local utility reliability. This analysis assumed that the only stakeholders who have standing in this analysis include utilities, ratepayers, governments, and residents who live within the boundary of the Texas independent operating utilities. It is possible that there are other stakeholders who will be impacted if the share of underground line miles increases. It is assumed that future weather through 2050 (e.g., number of lightning strikes, annual temperature, precipitation, average wind speed) will be similar to weather observed during the 2000–2012 time period. However, it is highly likely that future weather (climate) will not be similar to what has been recently observed (IPCC 2014). Future research could entail mapping state-of-the-art projections of local storm activity and temperature to each utility and recalibrating the analysis. Increased annual temperatures and storm activity will increase the estimated benefits of undergrounding T&D lines. It is also possible that the estimates of increased injury costs due to undergrounding may be less than the economic value of quality life to injured electric utility workers—or that undergrounding may, in fact, reduce health and safety risks to the general population. There is also emerging research indicating that underground lines are less efficient than overhead lines, which would increase the costs of undergrounding relative to the overhead status quo. Furthermore, this analysis did not consider the possibility that customers—especially commercial and industrial customers—may have installed backup generators or other technologies to reduce the risk of power interruptions. Another key assumption is that electric utilities in Texas are able to pass along all of their additional costs (due to undergrounding) to ratepayers. Despite these shortcomings, this section introduces a modeling framework that could be improved upon and extended to other regions who are interested in the economics of electric utility reliability.

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Technical Appendix

Table A - 1. Key data sources for lifecycle cost analysis

Data	Value	Original units	Source
Existing distribution lines (underground)	46,669	Total miles	Brown (2009)
Existing distribution lines (overhead)	165,158	Total miles	Brown (2009)
Existing transmission lines (overhead)	33,060	Total miles	Brown (2009)
Existing transmission lines (underground)	81	Total miles	Brown (2009)
Age of existing underground distribution line circuits (2012)	Derived	Age in years	Derived by author using average age of other T&D systems—20 years (Northwestern Energy 2011; Southern California Edison 2013)
Age of existing overhead distribution line circuits (2012)	Derived	Age in years	Derived by author using average age of other T&D systems—20 years (Northwestern Energy 2011; Southern California Edison 2013)
Age of existing overhead transmission line circuits (2012)	Derived	Age in years	Derived by author using average age of other T&D systems—20 years (Northwestern Energy 2011; Southern California Edison 2013)
Age of existing underground transmission line circuits (2012)	Derived	Age in years	Derived by author using average age of other T&D systems—20 years (Northwestern Energy 2011; Southern California Edison 2013)
Discount rate	10%	Weighted average cost of capital (%)	Public Utilities Fortnightly (2013); Brown (2009)
Annual line mile growth rate	2%	% per year	Author
Useful lifespan (underground infrastructure)	40	Years	Brown (2009)
Useful lifespan (overhead infrastructure)	60	Years	Brown (2009)
Annual O&M cost; first year (overhead transmission lines)	5%	% of replacement cost	Author estimated based on information submitted to FERC/RUS/EIA/Ventyx (2014)
Annual O&M cost; first year (overhead distribution lines)	0.5%	% of replacement cost	Author estimated based on information submitted to FERC/RUS/EIA/Ventyx (2014)

Data	Value	Original units	Source
Annual O&M cost; first year (underground transmission lines)	5%	% of replacement cost	Author estimated based on information submitted to FERC/RUS/EIA/Ventyx (2014)
Annual O&M cost; first year (underground distribution lines)	0.5%	% of replacement cost	Author estimated based on information submitted to FERC/RUS/EIA/Ventyx (2014)
Annual O&M cost growth rate; subsequent years (overhead transmission lines)	5%	% per year	Author estimated based on past annual T&D cost growth rate (Whitman, Requardt and Associates, LLP 2013)
Annual O&M cost growth rate; subsequent years (overhead distribution lines)	5%	% per year	Author estimated based on past annual T&D cost growth rate (Whitman, Requardt and Associates, LLP 2013)
Annual O&M cost growth rate; subsequent years (underground transmission lines)	5%	% per year	Author estimated based on past annual T&D cost growth rate (Whitman, Requardt and Associates, LLP 2013)
Annual O&M cost growth rate; subsequent years (underground distribution lines)	5%	% per year	Author estimated based on past annual T&D cost growth rate (Whitman, Requardt and Associates, LLP 2013)
Replacement cost (overhead transmission lines)	$180,000	$ per mile	Brown (2009)
Replacement cost (overhead distribution lines)	$104,000	$ per mile	EEI (2013) minimum values plus 20%
Replacement cost (underground transmission)	$1,680,000	$ per mile	EEI (2013) minimum values plus 20%
Replacement cost (underground distribution)	$357,000	$ per mile	EEI (2013) minimum values plus 20%
Replacement cost annual growth/decay rate (overhead transmission lines)	0%	% per year	Author
Replacement cost annual growth/decay rate (overhead distribution lines)	0%	% per year	Author
Replacement cost annual growth/decay rate (underground transmission lines)	0%	% per year	Author
Replacement cost annual growth/decay rate (underground distribution lines)	0%	% per year	Author
Length of each T&D system circuit	Derived	Length in miles	Derived by author using average circuit length of 25 miles

Table A - 2. Key data sources for administrative, permitting, and siting costs

Data	Value	Original units	Source
Administrative, permitting, and siting cost adder in first year	1% of installation cost in first year	%	Author
Administrative, permitting, and siting cost adder for converting overhead to underground in first year	2% of installation cost in first year	%	Author

Table A - 3. Key data sources for benefits of avoided power outages

Data	Value	Original units	Source
Model of U.S. electric utility reliability	See Table A-7	Regression coefficients	Larsen et al. (2015)
Delivered electricity per customer	33.96	MWh/customer	Author
Lagged T&D expenditures	0.39	$ per customer	Author
Years since outage management system installed	2.28	Years	Author
Presence of outage management system	1	Dummy variable	Author
Heating degree-days (positive deviation)	3.64	% deviation above mean	Author
Cooling degree-days (positive deviation)	3.74	% deviation above mean	Author
Lightning strikes (positive deviation)	14.54	% deviation above mean	Author
Wind speed (positive deviation)	1.85/10.69	% deviation above mean and % deviation squared	Author
Precipitation (positive deviation)	11.4	Positive precipitation deviation and deviation squared	Author
Precipitation (negative deviation)	-11.4	Negative precipitation deviation and deviation squared	Author
Year	Derived	Years (2013-2050)	Author
Customers per line mile	75	Customers per line mile	Author—variable is used to calibrate status quo SAIFI estimates; Brown (2009) reports 28.5 customer per line mile and author database reports 239.1 for Texas/ERCOT utilities
Existing share of T&D line miles	19.1%	%	Brown (2009)

Data	Value	Original units	Source
underground			
Future share of underground T&D line miles	Derived	%	Author derived during lifecycle analysis
Outage cost—commercial and industrial customers	$9,217	$ per customer outage	Sullivan et al. (2010) for large commercial and industrial (30 min. duration)
Outage cost—residential customers	$2.7	$ per customer outage	Sullivan et al. (2010) assumption for residential (30 min. duration)
Outage cost—other customers	$435	$ per customer outage	Sullivan et al. (2010) assumption for small commercial and industrial (30 min. duration)
Number of customers	6,983,069	Customers	Brown (2009)
Share of commercial and industrial customers	11.9%	%	Author derived based on U.S. Energy Information Administration via Form 861 (EIA 2013); Ventyx Velocity Suite via FERC et al. (2014); and U.S. Department of Agriculture Rural Utilities Service/ABB Ventyx (2015)
Share of residential customers	86.5%	%	Author derived based on U.S. Energy Information Administration via Form 861 (EIA 2013); Ventyx Velocity Suite via FERC et al. (2014); and U.S. Department of Agriculture Rural Utilities Service/ABB Ventyx (2015)
Share of other customers	1.6%	%	Author derived based on U.S. Energy Information Administration via Form 861 (EIA 2013); Ventyx Velocity Suite via FERC et al. (2014); and U.S. Department of Agriculture Rural Utilities Service/ABB Ventyx (2015)

Table A - 4. Key data sources for aesthetic benefits

Data	Value	Original units	Source
Median value of Texas residential real estate	$139,400	$	Zillow (2014)
Approximate median value of Texas commercial and industrial real estate	$1,000,000	$	Lincoln Institute (2011)
Median value of Texas other real estate	$500,000	$	Author
Total service area for Texas IOUs	190,597	Square miles	Author derived from public sources
Width of transmission viewing corridor	600	Feet	Approximate average of Sims and Dent (2005) and Colwell (1990)
Property loss factor attributed to view of transmission line	12.5%	%	Average of range of values reported by Des Rosiers (2002)

Table A - 5. Key data sources for impacts to ecosystems

Data	Value	Original units	Source
Width of ecosystem footprint (overhead transmission line)	60	Feet	Author
Width of ecosystem footprint (underground transmission line)	120	Feet	Author
Conservation easement price (Texas)	$3,000	$ per acre	The Nature Conservancy (2014)

Table A - 6. Key data sources for health and safety costs

Data	Value	Original units	Source
Value of statistical life	$6,900,000	Dollars	Executive Office of the President (2013b)
Aggregate number of employees	8,514	Number of employees	Author estimated from public sources
Maximum cost of utility-related accident (electric shock)	$130,658	$ per accident	U.S Department of Labor (2014)
Incidence rate for electric utility (non-fatal injury)	2,100	Accidents per 100,000 workers	U.S. Department of Labor (2014)
Incidence rate for electric utility (fatality)	15	Fatalities per 100,000 workers	U.S. Bureau of Labor Statistics (2014)

Table A - 7. Results for base SAIFI and SAIDI regressions (Larsen et al. 2015)

Dependent variable:

Explanatory variables:	Log of SAIDI (with major events)	Log of SAIFI (with major events)
Intercept	-185.236*** (49.627)	-23.488 (20.295)
Electricity delivered (MWh per customer)	0.004 (0.015)	-0.005 (0.011)
Abnormally cold weather (% above average	0.004 (0.013)	0.002 (0.005)
Abnormally warm weather (% above average	-0.008* (0.004)	0 (0.001)
Abnormally high # of lightning strikes (% above e strikes)	0.001 (0.002)	0.002** (0.001)
Abnormally windy (% above average wind	0.121*** (0.031)	0.04*** (0.012)
Abnormally windy squared	-0.007*** (0.002)	-0.003*** (0.001)
Abnormally wet (% above average total ation)	0.01* (0.005)	0.002 (0.001)
Abnormally dry (% below average total ation)	0.001 (0.005)	0.003* (0.002)
Outage management system?	0.128 (0.136)	-0.02 (0.051)
Years since outage management system tion	-0.02 (0.025)	0 (0.012)
Year	0.095*** (0.025)	0.012 (0.01)
Lagged T&D O&M expenditures ($2012 per er)	0 (0.07)	-0.069 (0.184)
Number of customers per line mile	0.006 (0.007)	0.008 (0.005)
Share of underground T&D miles to total T&D	-0.014**	-0.001

Explanatory variables:	Dependent variable: Log of SAIDI (with major events)	Log of SAIFI (with major events)
	(0.007)	(0.004)
Degrees of freedom:	335	292
Number of utilities:	46	46
Adjusted R^2	0.14	0.71
Root mean square error	0.73	0.26
Utility effects:	Random	Fixed

Notes:

(1) Standard errors are presented in parentheses underneath coefficient.
(2) *** represents coefficients that are significant at the 1% level.
(3) ** represents coefficients that are significant at the 5% level.
(4) * represents coefficients that are significant at the 10% level.
(5) † represents preferred model specification.

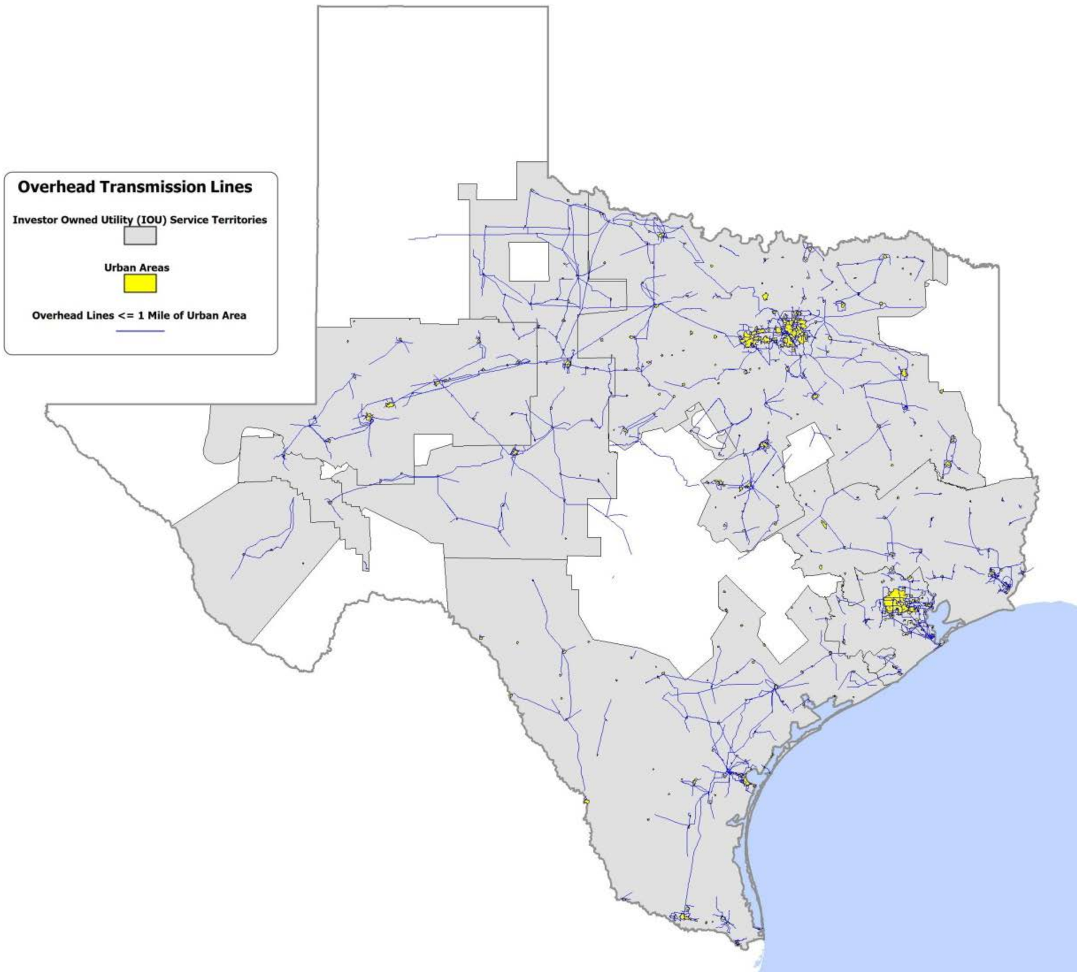

Figure A-1. Overhead transmission lines near urban areas within investor-owned utility service territories

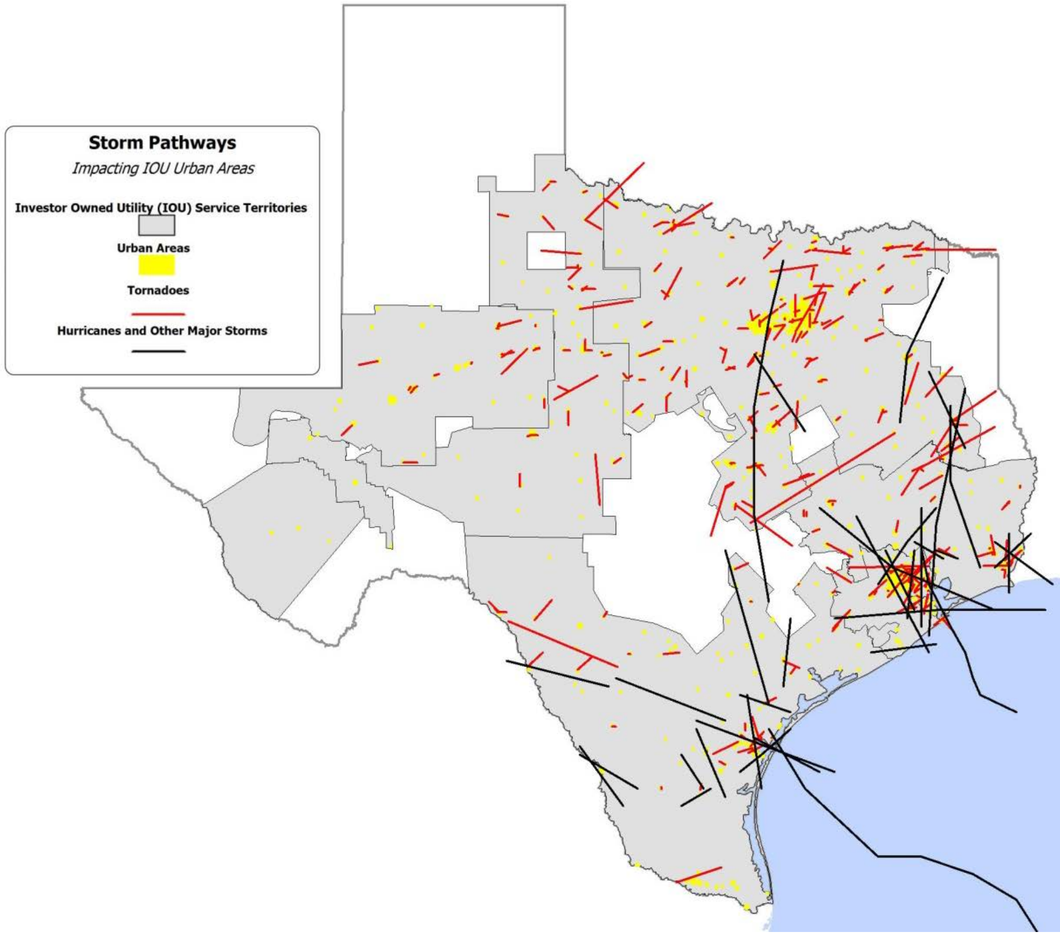

Figure A-2. Major storm pathways impacting urban areas within investor-owned utility service territories