Edison Electric Institute

Out of Sight, Out of Mind 2012

An Updated Study on the Undergrounding Of Overhead Power Lines

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Executive Summary

Since the late 1990s, numerous state studies and reports have been generated in response to the electric service outage impact of unusually large storms. At the writing of this report, states from the mid-Atlantic to New England are recovering from Hurricane Sandy. The storm's devastation will certainly trigger one additional side-effect: many utility commissions will scrutinize their utility's response to the event.

Following any major storm where a large percentage of the electrical grid is affected for an extended period, utilities, customers, public officials, and the media will undoubtedly study the performance response of any utility impacted by the storm. It is not uncommon for this focus to turn to discussing whether plans on migrating from an overhead (OH) to an underground (UG) electrical infrastructure would resolve or substantially mitigate, weather related outages. Even when storms are not wreaking havoc on the electric utility infrastructure, there are many communities that express the desire to improve the aesthetics of their neighborhoods and roadways by undergrounding all utilities. There are many issues to consider before such a transition can be implemented because undergrounding the system has substantial implications for the reliability, cost, and aesthetics of the electrical system.

Many states have issued reports which addressed whether undergrounding the electric utility's infrastructure would improve the reliability and availability of electric service during and after major storms. Currently, no state has recommended wholesale undergrounding of their utility infrastructure. The cost of conversion has always been the insurmountable obstacle in each of these studies.

In this fourth edition of the *Out of Sight, Out of Mind* report, the Edison Electric Institute (EEI) has updated the data set collected in the 2009 edition to help provide additional information to guide utilities, states and our customers' consideration of these issues.

Because of the importance of the cost of utility services to electrical customers, EEI polled electric customers concerning their willingness to pay for undergrounding. The results indicated that 60 percent of electric customers were willing to pay at least 1−10 percent more on their power bills for undergrounding and another 11 percent of customers were willing to pay up to 20 percent more. However, fewer than 10 percent of the customers polled were willing to incur a bill increase of 100 percent to pay the more realistic cost for undergrounding. This information confirms the experience of most utilities and state commissions that the cost of undergrounding is a very important consideration and that customers have limited tolerance for higher costs for utility services to pay for undergrounding.

EEI also looked at major storm data from the previous nine years to determine what trends and impact these events are having on the electric industry. The data was somewhat inconclusive because the number of storms had increased, but the average outage time per customer declined at times. This may simply mean that utility restoration responses have improved with the increased use of mutual assistance. Some measures of reliability indicate that underground electric infrastructure has only a slightly better reliability performance than overhead electric systems, while other measures show a higher reliability factor for underground facilities. One explanation may be that many underground facilities are fed by overhead facilities which can become disabled during storms. But it is important to remember than repairs to underground facility outages are often more complex and time consuming and such facilities are more costly to upgrade and replace. And as recent experiences with Hurricane Sandy demonstrate, underground facilities are very vulnerable to flooding and water damage.

The data collected this year, once again, demonstrated that new underground construction can be five to ten times more expensive than new overhead constructions. It is worth noting that although the conversion cost per mile appears to be less, much of the conversion cost is reduced by the salvage value of the overhead material being removed. Despite the higher cost of underground construction, utilities do find value in building underground facilities. This is particularly true for new developments where undergrounding can be accomplished along with the building of other basic infrastructure. Thus, it is not surprising that nearly all new residential and commercial developments in the United States are served with underground electrical facilities. In fact, every year for the last 13 years, utilities working with communities and customers have committed over 20 percent of new distribution construction expenditures toward the building of underground distribution facilities. In comparison, the portion of underground transmission construction has been much smaller and more varied, because undergrounding of transmission is much rarer and much more expensive.

The most significant obstacle to undergrounding utility infrastructure arises with efforts to convert existing overhead facilities to underground because of the high cost of making these conversions. Conversion costs can vary significantly depending on location-specific issues. While some recent data suggests that conversion costs are not much higher than initial installation costs (largely because of the salvage value of equipment), these numbers do not take into account other costs associated with conversions: the cost of converting individual customers' services/metering points so they can be connected to the new underground facilities and the substantial disruption caused by the undergrounding construction process (avoiding conflict with or limiting the damage to existing trees, walls, fences and other underground utilities).

Given the cost impact of converting existing overhead distribution facilities to underground and customer concerns about utility cost increases, a wholesale move to underground most existing utility distribution facilities is probably prohibitively expensive. However, a few states and utilities have developed policies and procedures designed to encourage the utility and the local municipality to work together to convert select overhead areas to underground. Potential criteria to apply in selecting such facilities include susceptibility to outages, number of customers served, cost of conversion and ability to recover conversion costs from the customers that may benefit. In some cases, the municipality may be able to defray some of the conversion costs or the utility may be allowed to add the conversion costs to the rate base for the customers within a localized district.

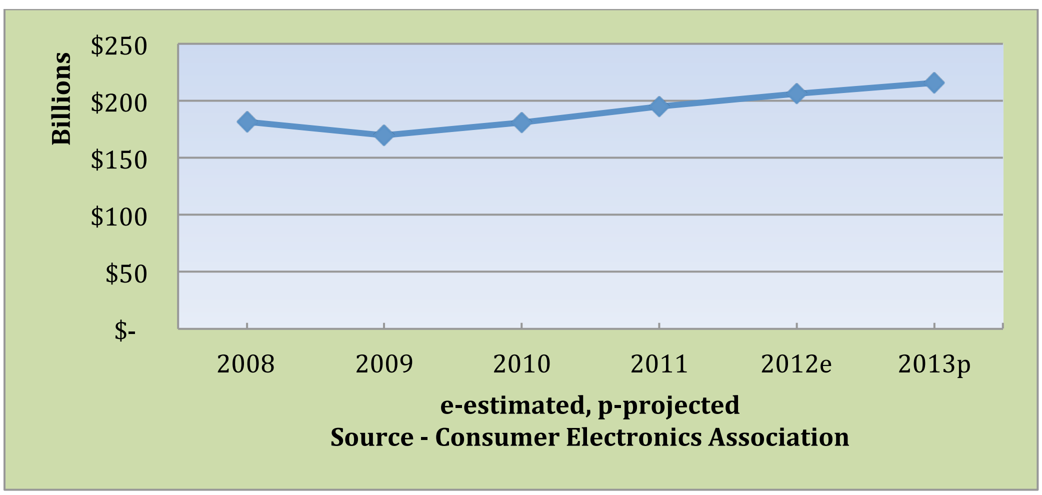
The future of such conversions will hinge on the ability of customers, utilities and utility regulators to work together to find viable funding approaches that meet customer expectations and compensate utilities for the cost of placing electrical facilities underground.

Chapter 1: Customer Expectations

Historically, consumer expectations and desires have helped guide the development of the electric utility industry, from its beginning in Thomas Edison's workshop to the vast network of cables and wires that currently comprise the modern electrical grid. The creation of the electrical grid and the priorities of electric customers have shaped the development of the industry. Reliability of electrical service, public safety, cost of service, and electrical system aesthetics have presented challenges and opportunities for electric utilities as they have sought to balance customer expectations while providing reliable electrical service at a reasonable price.

As a society, we are more digitally connected today than we could have comprehended 25 years ago. In the late 1980s, cell phones were big, bulky items that only a few people had and email was just starting to penetrate the business world as an effective form of communication. Today, most Americans have a cell phone, a personal computer, and many other handheld electronic devices. The Consumer Electronics Association notes that, in 2012, the average U.S. household owns 24 consumer electronic devices and this number has been growing annually. To give a perspective on this growth, the chart in Figure 1.1, Total Sales of Consumer Electronics, indicates that Americans have spent more than $169,000 million annually on consumer electronic devices each of the last five years.

Figure 1.1 Total Sales of Consumer Electronics



As the demand for electronic devices has increased, so has the consumer's sensitivity to electric outages. These devices provide connectivity to information and communications that Americans expect to use for business and leisure. When that connectivity is broken, such as during a power outage, there is little tolerance for any prolonged outage duration.

Because of this sensitivity, an ongoing topic of discussion in the utility-customer relationship is the desire for a more reliable electric system with fewer outages. Customers tend to think that if the electric system could be migrated from an overhead to an underground electrical infrastructure, the outage issue would be resolved. There are merits for making this transition, but there is significant cost involved to make it happen. In some cases, the desire for undergrounding is driven by utility needs; in other cases, it is a request spearheaded by customers. Regardless, undergrounding the system has implications for the reliability, cost, and aesthetics of the system.

Customer Feedback

Several times a year, the Edison Electric Institute (EEI) polls Americans regarding various energy related issues. As part of the EEI third-quarter Power Poll, questions were asked to discern the desire of customers to have electrical lines placed underground. A total of 1003 interviews were completed online with residential customers across the nation between October 5 and October 11, 2012. Those interviewed were asked several demographic questions to gauge perspectives from different regions of the country (Northeast, Midwest, South, or West) and different population density areas (urban, suburban, or rural).

Figure 1.2, Undergrounding Wires, asked the question "Are the electric wires that serve your home overhead or underground?" Of all respondents, 39 percent indicated that they have underground service. The region of the country with the larger amount of underground service was the South with 47 percent. In fact, more people in the South responded that they had underground service than overhead service. Contrary to what may have been expected for responses broken out by population density, people living in suburban areas indicated that 49 percent of them have underground service.

Figure 1.2 Undergrounding Wires

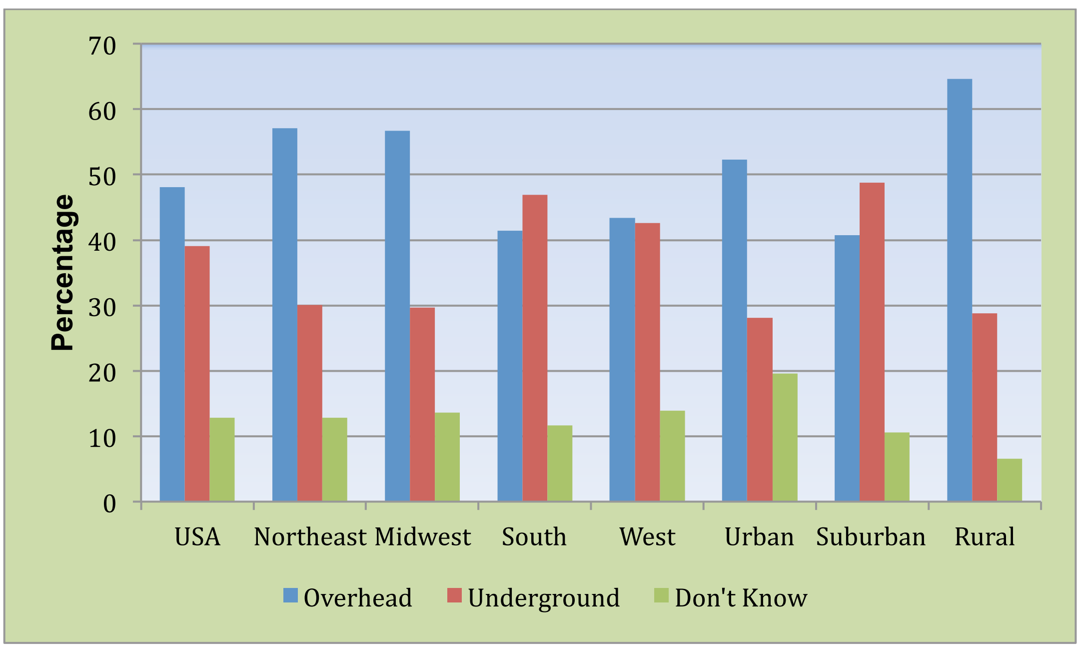
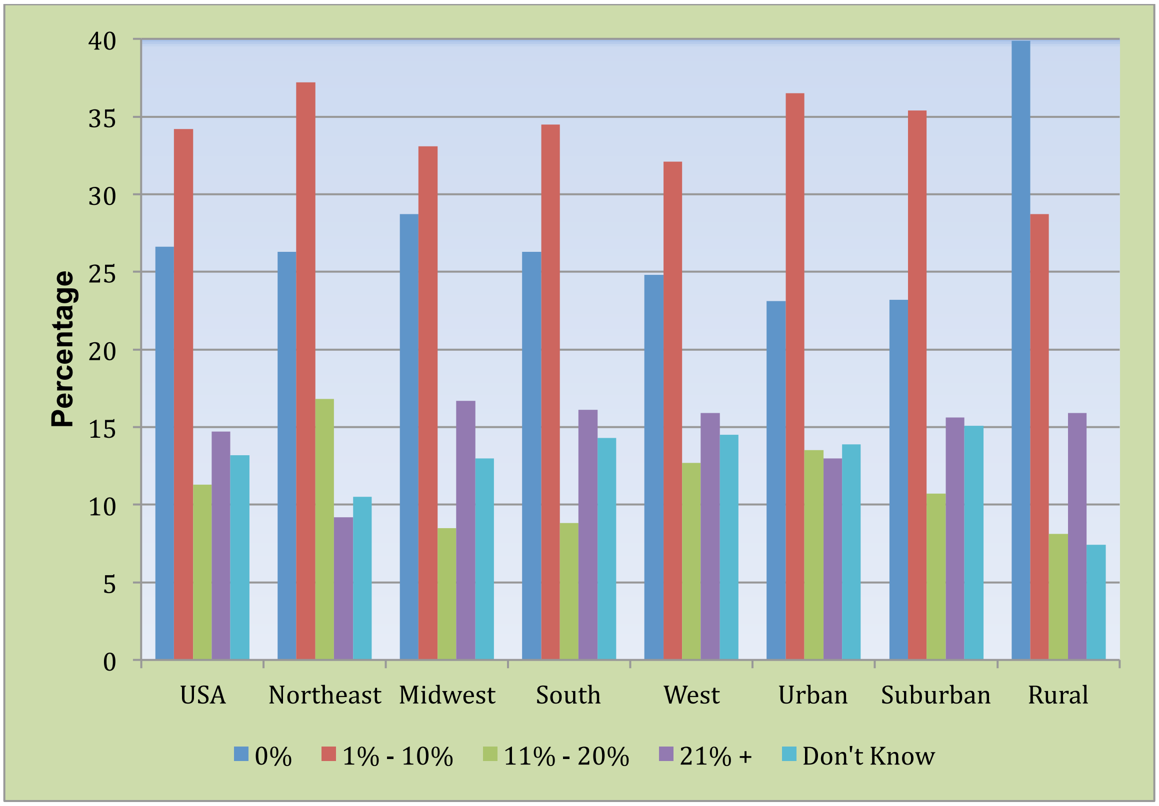


Figure 1.3, paying for Undergrounding, depicts the results from the question "How much more, as a percentage of your electric bill, would you be willing to pay to have the electric wires that serve your neighborhood placed underground?" Participants were given the choices: no increase, 1−10 percent increase, 11−20 percent increase, 21+ percent increase, or Don't Know. For the entire country, 34 percent of the respondents were willing to pay between 1−10 percent in additional costs on their electric bill to have utility facilities placed underground, with an additional 26 percent willing to pay more. The rural section of the polled participants had the largest group, 40 percent, who were not willing to pay anything for undergrounding.

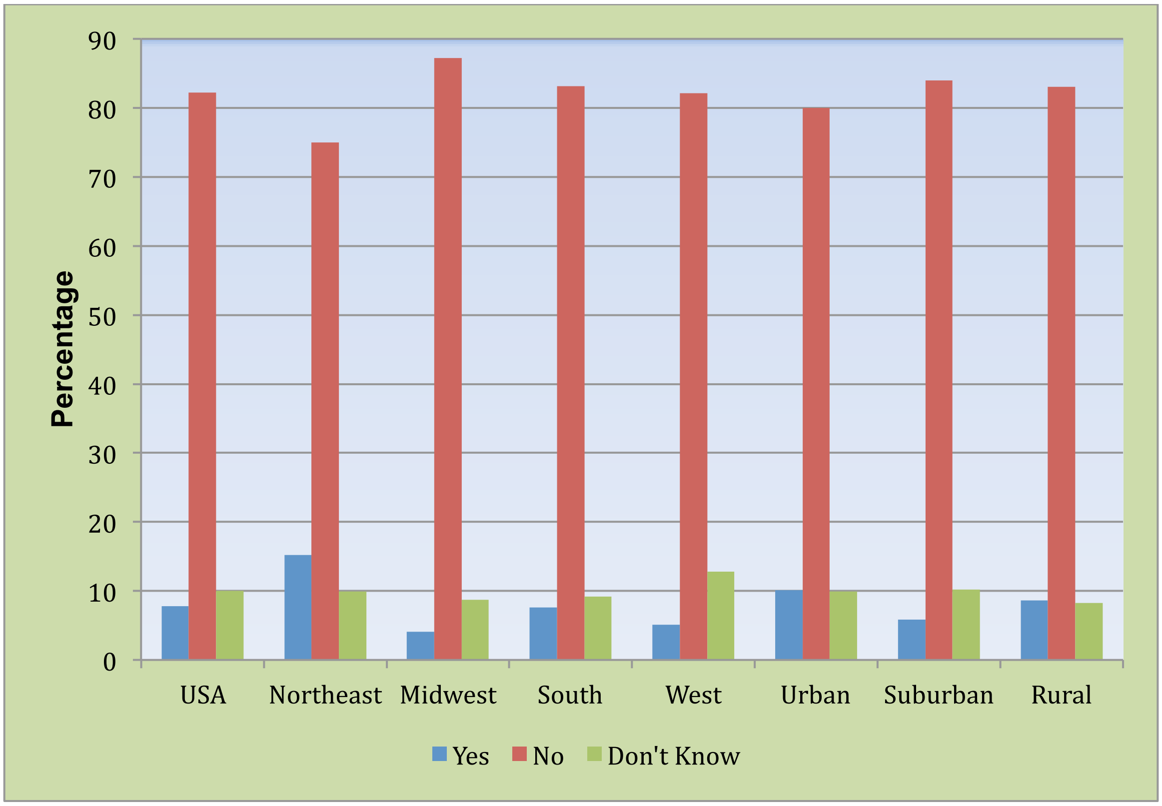
Figure 1.3 Paying for Undergrounding



With estimated costs to underground an entire electric utility in the billions of dollars, the impact to utility customers could result in their utility bill doubling. The North Carolina 2003[1] study noted that "the ultimate impact of the capital costs alone on an average residential customer's monthly electric bill would be an increase of more than 125 percent" to underground the electric facilities. EEI posed the question "Would you be willing to pay 100 percent more on your electric bill to have the electric wires that serve your neighborhood placed underground?" Figure 1.4, Doubling Power Bill, presents the overwhelming response from all parts of the country as "no."

1 Report of The Public Staff to The North Carolina Natural Disaster Preparedness Task Force, *The Feasibility of Placing Electric Distribution Facilities Underground*, November 2003.

Figure 1.4 Doubling Power Bill



This presents the biggest challenge of the whole undergrounding issue: customers want wires underground, but are unwilling to pay the cost of placing them there.

Reliability

Placing electric facilities underground can improve system reliability; however, many customers assume that by placing electric lines underground that all electrical interruptions will cease. It is true that underground lines are not prone to many of the typical overhead outage causes, but underground electrical systems do have their share of outage events that are unique to underground systems. Chapter 3 will discuss the impact that placing lines underground has on the overall reliability of the system, while investigating available reliability data comparing overhead and underground systems. Chapter 5 will discuss the types of inherent reliability issues underground facilities contribute to the grid.

Undergrounding Costs

Much of new construction is currently being placed underground by utilities across the country. The real issue is how to address existing overhead facilities. The cost of placing these existing electrical facilities underground is an issue of contention between utilities and customers. For many utilities, the cost of installing new underground facilities is covered in existing rates. The cost of converting existing overhead facilities to underground becomes the major impediment that utilities and customers face in the process of making this transition. To assist with these additional costs, utilities normally seek some type of cost recovery from the customers who desire this conversion. However, many customers would like these underground facilities to be installed at little or no cost, as noted in the EEI polling data. Chapter 6 will investigate the cost issue as it relates to installing underground facilities and converting to an underground system. Also, Chapter 7 provides summary information regarding how various state commissions have dictated the customer cost contribution for undergrounding.

Aesthetics

Aesthetics is a primary factor in placing lines underground (see Figure 1.2, illustrating New York City in the late 1800s). Most customers today prefer a more natural looking landscape, one that is not framed by wires and poles. To respond to customer concerns, most utilities have policies or procedures that prescribe how and when a utility places facilities underground. Chapter 7 discusses current policies and procedures that utilities are using to address these changes.

Figure 1.2 New York City in the late 1800s

Chapter 2: Storms and Outages

Restoring power to all affected customers in the aftermath of a large storm can take several days for most utilities. To expedite the restoration process following most major storms, utilities will bring in thousands of extra lineworkers from other utilities and work around the clock to "get the lights back on." Industry experience has shown that customers are somewhat understanding of the fact that the restoration process takes time, but their tolerance has its limits because outages lasting longer than a day or two are disruptive to everyday life.

Large events can also create an environment where customer expectations are difficult to meet. Most regions of the country have their typical large storm events. For example, utilities in the southeastern United States have extensive experience with the process to rebuild and recover from hurricanes, while the northern utilities have more experience with ice and snow storms. Unexpected or unusually large storms tend to lengthen total restoration times due to the need to mobilize additional resources and crews. As workforce demands increase, the mobilization time increases because workers are being brought in from states far away from the recovery area. During the recovery from Hurricane Sandy in 2012, crews from the west coast were being sent to assist with the recovery in New York and New Jersey.

After a large event, it has become common for customers, local officials, and even state utility commissions to push for putting some or all of the utility's electrical facilities underground. Table 2.1, Major Storms and Resulting State Studies, lists some of the major storms and the ensuing studies that have been performed in the wake of such storms over the past 10 years.

Table 2.1 Major Storms and Resulting State Studies

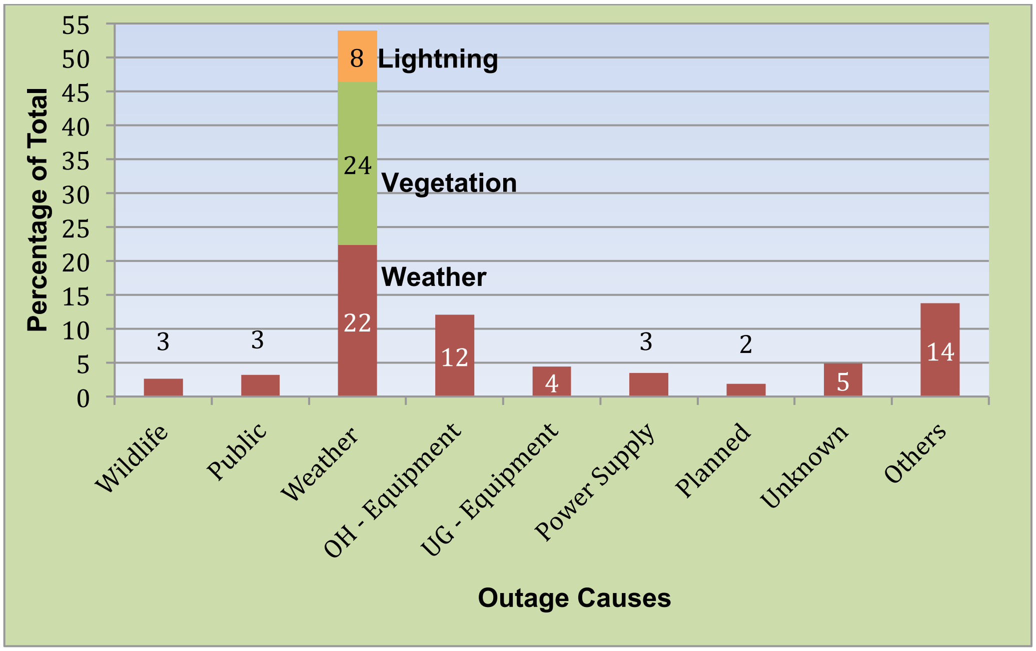
Storm	Year	Study
Derecho Hurricane Irene Snow Storm	2012	2012, September 24—*Weathering the Storm: Report of the Grid Resiliency Task Force*, Office of Governor Martin O'Malley of Maryland, Executive Order 01.01.2012.15
June 2012 Derecho	2012	2012, August—Infrastructure Security and Energy Restoration, Office of Electricity Delivery and Energy Reliability, U.S. Department of Energy *A Review of Power Outages and Restoration Following the June 2012 Derecho*
Hurricane Irene Snow Storm of October 29, 2011	2011	2012, August 9—New Jersey Board of Public Utilities *Performance Review of EDCs In 2011 Major Storms*
Hurricane Irene	2011	2012, August 7—Pennsylvania Public Utilities Commission *Summary Report of Outage Information Submitted by Electrical Distribution Companies Affected by Hurricane Irene (Aug. 27−28, 2011)*
October 2011 Snowstorm	2011	2011, December 1—State of Connecticut *Connecticut October 2011 Snowstorm Power Restoration Report*

	2010	2010, July 1—Public Service Commission of the District of Columbia *Study of the Feasibility and Reliability of Undergrounding Electric Distribution lines in the District of Columbia*
Hurricane Ike	2008	2009, April 21—Houston, Texas *Electric Service Reliability in the Houston Region,* Mayor's Task Force Report
December Ice Storm	2007	2008, June 30—Oklahoma *Oklahoma Corporation Commission's Inquiry into Undergrounding Electric Facilities in the State of Oklahoma*, Prepared and Submitted by Oklahoma Corporation Commission Public Utility Division Staff
Hurricane Dennis Hurricane Katrina Hurricane Ophelia Hurricane Rita Hurricane Wilma	2005	2008, May 21—Florida *Undergrounding Assessment Phase 3 Report: Ex Ante Cost and Benefit Modeling* by Richard Brown, Quanta Technology
Hurricane Dennis Hurricane Katrina Hurricane Ophelia Hurricane Rita Hurricane Wilma	2005	2007, August 6—Florida *Undergrounding Assessment Phase 1 Report: Undergrounding Case Studies* by Richard Brown, InfraSource Technology
Hurricane Dennis Hurricane Katrina Hurricane Ophelia Hurricane Rita Hurricane Wilma	2005	2007, February 28—Florida *Undergrounding Assessment Phase 1 Final Report: Literature Review and Analysis of Electric Distribution Overhead to Underground Conversion* by Richard Brown, InfraSource Technology
Hurricane Isabel	2003	2005, January 7—Virginia *Placement of Utility Distribution Lines Underground*, Report to the State Corporate Commission
January Ice Storm/ Hurricane Floyd	1999	2003, December 30—Maryland *Task Force to Study Moving Overhead Utilities Lines Underground*
December Ice Storm	2002	2003, November 21—North Carolina *The Feasibility of Placing Electric Distribution Facilities Underground*, Report of The Public Staff to The North Carolina Natural Disaster Preparedness Task Force

Outage Data

Weather plays a significant factor on the total number of outages that electrical systems experience. A summary of data collected between 2000 and 2011 by EEI as part of their annual Reliability Report shows that 54 percent of all outages are the result of weather or its effects. Figure 2.1, Outage Causes by Percentage (2000−2011 Combined), gives a perspective of how weather and related categories contribute to system outages.

Figure 2.1 Outage Causes by Percentage (2000−2011 Combined)



The contributing weather related categories from the EEI report are: lightening 8 percent, weather 22 percent, and vegetation 24 percent (the latter is usually the result of wind blowing vegetation into contact with utility lines).

Storm Data

In this 2012 edition of the report, data from the U.S. Department of Energy (DOE) was analyzed to demonstrate how substantial the impact of weather is to electrical system outages. DOE monitors major system incidents on electric power systems and conducts investigations of significant interruptions of the electric power system. All electrical utilities are required to report large outages using DOE Form OE-417, "Electric Emergency Incident and Disturbance Report." An outage must be reported if it meets any of the following criteria:

1. Physical attack that causes major interruptions, impacts critical infrastructure facilities, or impacts operations
2. Cyber event that causes interruptions of electrical system operations
3. Complete operational failure or shut-down of the transmission and/or distribution electrical system
4. Electrical System Separation (Islanding) where part(s) of a power grid remain(s) operational in an otherwise blacked-out area or within the partial failure of an integrated electrical system
5. Uncontrolled loss of 300 Megawatts or more of firm system loads for more than 15 minutes from a single incident
6. Load shedding of 100 Megawatts or more implemented under emergency operational policy
7. System-wide voltage reductions of 3 percent or more
8. Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the electric power system

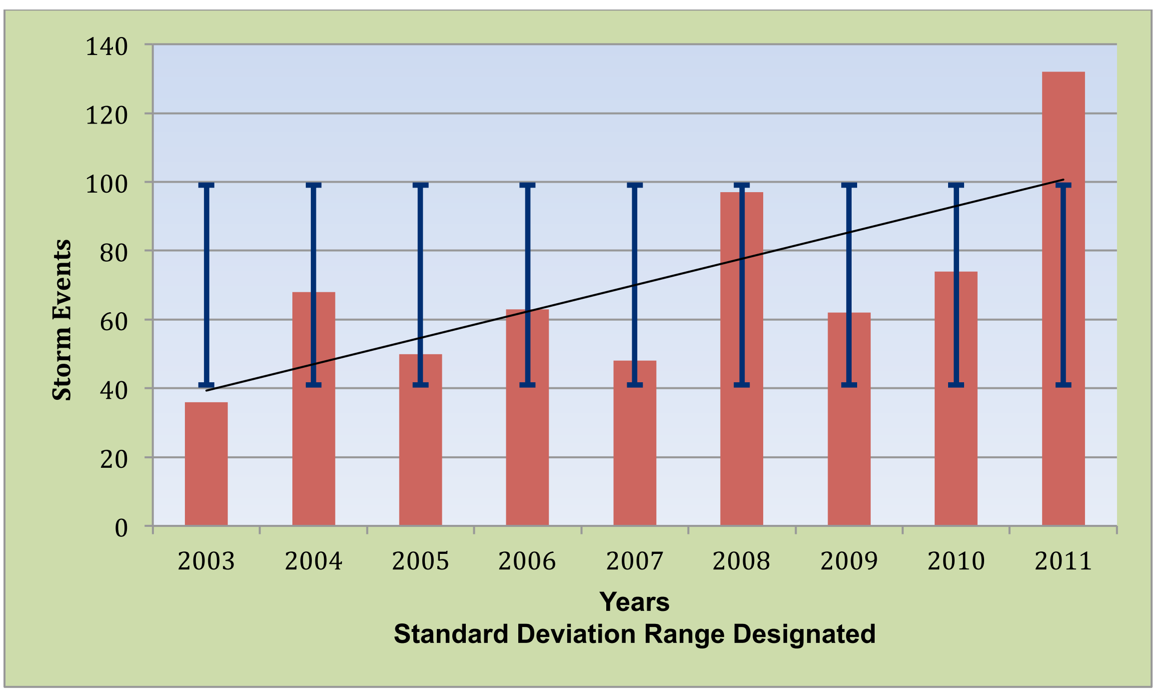
9. Physical attack that could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security system
10. Cyber event that could potentially impact electric power system adequacy or reliability
11. Loss of electric service to more than 50,000 customers for 1 hour or more
12. Fuel supply emergencies that could impact electric power system adequacy or reliability

The data collected from Form OE-417 is compiled by DOE's statistical agency, Energy Information Administration (EIA), to create publicly available information about electrical system outages. In this paper, EEI has reviewed and compiled available data for 2003 to 2011 to identify the impact and trends of major weather related outages during that nine-year period, and will discuss how the data has changed since the release of the 2009 *Out of Sight, Out of Mind* report. As noted in 2009, the current report does not include all system outages in the U.S., but only weather-related events that meet the OE-417 reporting requirement.

The following six figures provide information on the annual number of events,[2] the number of customers impacted, and the number of hours of annual outage.

Figure 2.2, EIA Data: Storm Events, exhibits the number of major weather events for each year. The outlier years for storm events are 2003 and 2011. All the other years fall within one standard deviation of ±27.3 events; this is an increase from the ±23 events shown in the 2009 report. The annual average of 70 events per year for all years increased from 57 events in the 2009 report. The data also shows an increased trend for more storms over the nine-year period.

Figure 2.2 EIA Data: Storm Events



[2] A single storm can count for more than one event if it impacts more than one utility. For example, Hurricane Ike (2008) resulted in nine utilities reporting outages to EIA; therefore, Hurricane Ike would account for nine events that year.

Figure 2.3, EIA Data: Customers Affected, shows the number of customers experiencing storm event outages annually. The outlier years for customers affected are 2007, 2008, and 2011. All the other years fall within one standard deviation of ±5.7 million customers; this is lower than ±6 million customers from the 2009 report. The annual average of 13.8 million customers experiencing an outage also fell from 14 million in the 2009 report. However, data shows an increasing trend for customers experiencing an outage event over this nine-year period.

Figure 2.3 EIA Data: Customers Affected

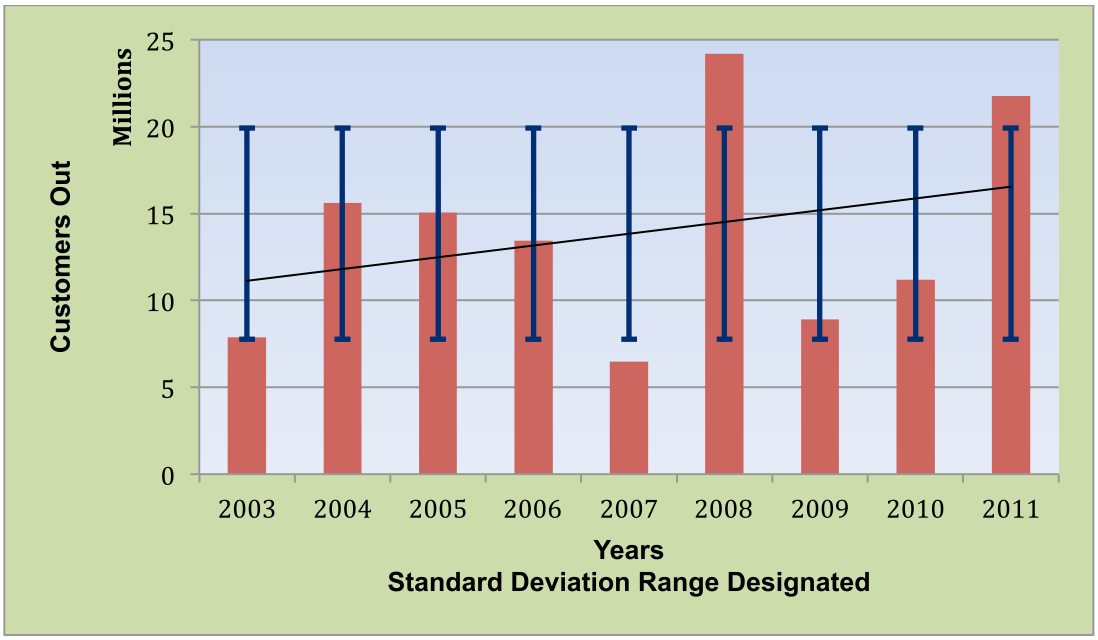


Figure 2.4, EIA Data: Hours of Interruptions, exhibits the total number of annual outage hours. The outlier years for hours of interruption are 2007, 2008, 2011, and the partial year 2012. Data for the other years falls within one standard deviation of ±1,814 hours; this is slightly lower than the ±1,900 hours in the 2009 report. The annual average of outage hours increased to 4,957 hours from the average of 4,770 hours from the 2009 report. The data shows an increasing trend for customers experiencing an outage event over the nine-year period.

Figure 2.4 EIA Data: Hours of Interruptions

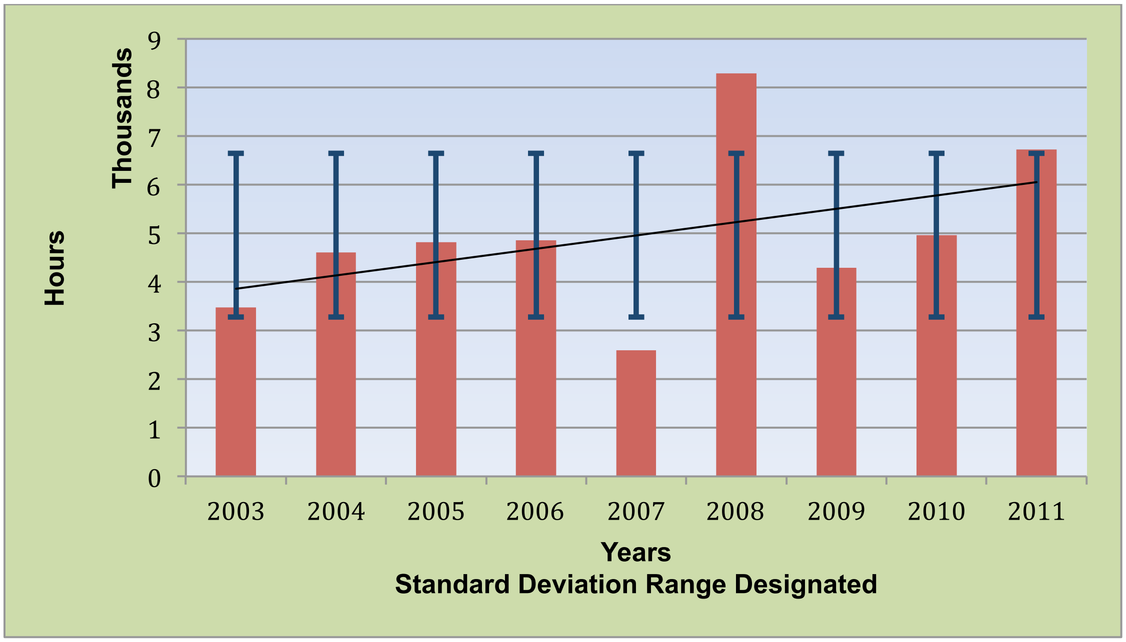


Figure 2.5, EIA Data: Customers Out per Reported Storm, represents the average number of customers experiencing an outage per storm. The outlier years for average number of customers experiencing an outage per storm are 2005, 2007, and 2009. Data for the other years falls within one standard deviation of ±51.8 thousand customers. The data shows a decreasing trend for customers out per storm over the nine-year period.

Figure 2.5 EIA Data: Customers Out per Reported Storm

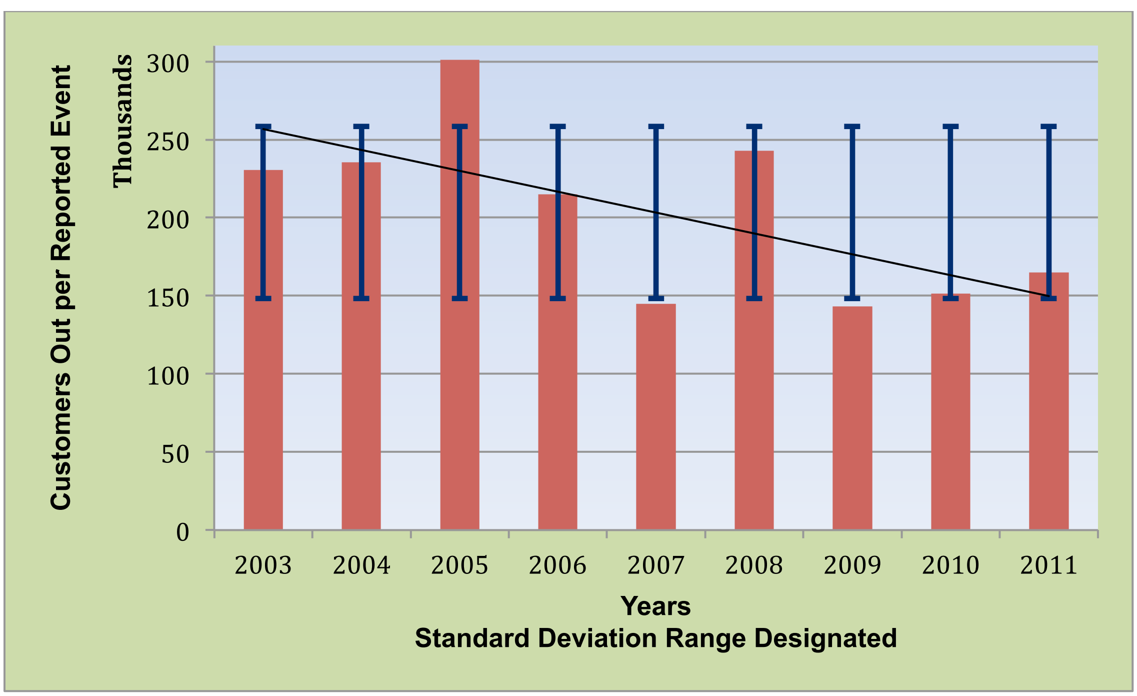
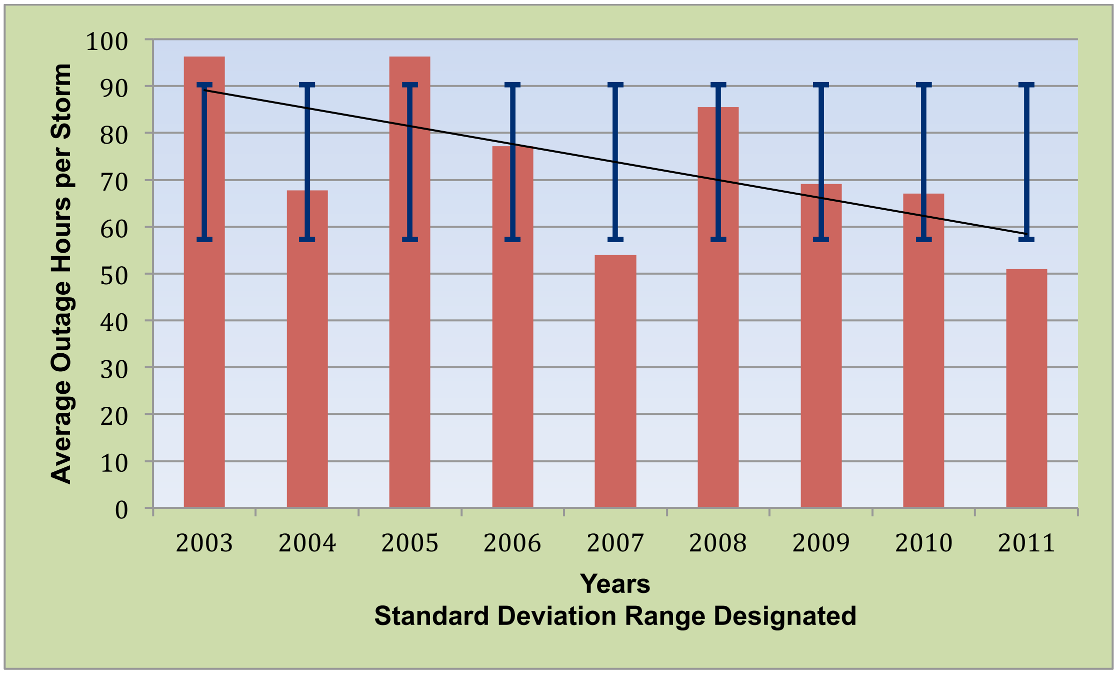


Figure 2.6, EIA Data: Average Outage Hours per Storm, represents the average outage hours per storm. The outlier years for average outage time per storm are 2003, 2005, 2007, and 2011. Data for the other years falls within one standard deviation of ±15.6 hours per storm. The data shows a decreasing trend for hours per storm over the nine-year period.

Figure 2.6 EIA Data: Average Outage Hours per Storm



The data in charts 2.2−2.6 reveals that over the last nine years the trends indicate an increase in the number of recorded storms, an increase in the total number of customers affected, and an increase in the total number of outage hours for the available data. The data demonstrated the trend for fewer customers being impacted per storm over the nine-year data set and that the trend for outage time has also decreased during this time. This implies that there have been more, but smaller storms over the past few years. This corresponds to the fact that there have been fewer hurricanes to make landfall in the last several years.

The data indicates that the annual weather-related outages do have an impact to the electrical grid each year. Some questions to consider at this point, after reviewing the EIA data for this nine-year period, include:

- How much of an impact do storms have on reliability statistics?
- Do underground facilities help to improve reliability statistics?
- Has the overall percentage of the underground electrical system increased during this time?
- If it has, has it contributed to any major improvement to reliability, according to the outage data available from EIA?

Chapter 4 will investigate what changes have taken place in the quantity of underground facilities and whether it has an impact on reliability.

Types of Storms

The next several figures will present the categories of storms that are most frequent, that affect the most customers, and that causes the largest amount of outage hours. The EIA data captures the "Type of Disturbance" for each outage; however, they have not created a standardized list of disturbances for uniformity in the data. For example, summer storms associated with rain, lighting, wind, and thunder have 47 different types of listings. In an effort to manage the data, this report has assigned each of the events to one of the following seven categories:

- Earthquake
- Flooding
- Heat Storm
- Hurricane/Tropical Storm
- Summer Storm (Lightning/High Winds)
- Wildfire
- Winter Storm (Ice/Snow)

Of these types of events, hurricanes/tropical storms, summer storms, and winter storms together make up more than 97.8 percent of all the events recorded. This report has included earthquakes, flooding, and wildfires in the listing because they are naturally-occurring events.

Figure 2.7, Percentages of Outage Hours, Storms Types, and Customers Out, is comprised of three charts showing the percentage breakdown for the Total Outage Hours, Type of Storms, and Total Customers Out for the summation of all events from 2003 to 2011. The data in the three pie charts consistently demonstrates that summer storms are the leading cause of electrical grid outages. However, because of fewer hurricanes/tropical storms over the last few years, summer storms have increased in their share of the percentage of all storms. The percentage difference between hurricanes/tropical storms and winter storms is minimal except when looking at the number of customers affected by the events. Again, it is worth reiterating that this data is only for major outage events reported to EIA.

Figure 2.7 Percentages of Outage Hours, Storms Types, and Customers Out

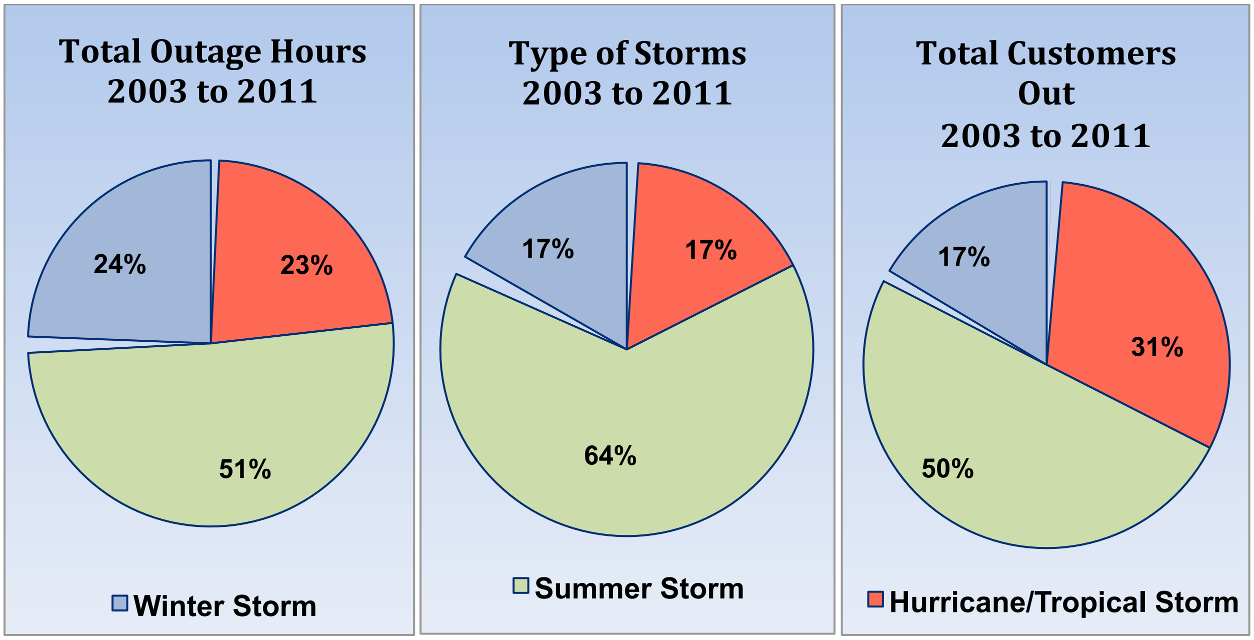
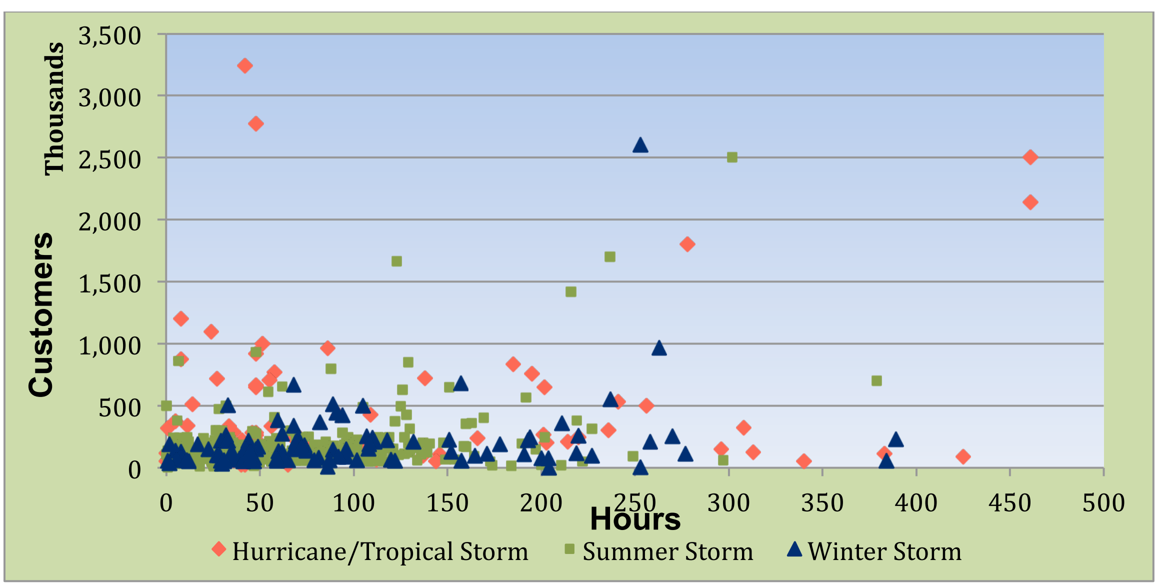


Figure 2.8, Customers vs. Hours, is a scatter plot of the number of customers affected compared to the length of the associated outage. As in the 2009 report, hurricane/tropical storms tend to be the more extreme events, affecting more customers and producing longer outage times. The data also illustrates that winter storms tend to have durations equal or greater than many of the summer storm events.

Figure 2.8 Customers vs. Hours



After analyzing EIA data on major storms over the last nine years, it may be deduced that storms that produce strong winds are the major cause of warm weather grid failures. The data shows that hurricanes/tropical storms and summer storms cause 80 percent of all major outages and that snow and ice accumulation are the major cause of system outages during the winter. From these observations, it would appear that underground facilities would be less prone to these types of major outage events. However, underground facilities are also affected by these major storms, because most existing underground facilities are supplied from overhead sections of the grid. So any event causing an overhead outage will also cause outages on sections of underground facilities.

In Chapter 3, we will investigate reliability of both overhead and underground electrical facilities to determine if customers served by either would experience any difference in service.

Chapter 3: The Reliability of Overhead and Underground Electrical Systems

For this report, the Edison Electric Institute captured and presented actual utility reliability data. An extensive survey was disseminated to EEI membership to gather information on reliability, construction costs, undergrounding policy information, and utility experiences with underground systems. A copy of the survey is included in Appendix A.

Reliability Data

Gathering and measuring reliability performance data is a task for which utilities commit significant resources. This data is invaluable to a utility in providing many different metrics that can be used to measure performance and by assisting the utility in developing mitigation plans to improve poor performing feeders and circuits.

There are many components associated with each outage event that a utility must capture to compile reliability statistics. A utility must know when an outage event starts, determine how many customers are impacted, identify the cause of the outage, and capture the time when each customer is restored. This may appear simple, but consider the complexity of managing the data collection for a major outage event with hundreds of thousands of customers without service and up to 10,000 lineworkers repairing and restoring the electrical system. Utilities have developed complex data gathering systems to assist in collecting and managing the information of outages which allows utilities to better understand the causes of outages and to identify more effective ways to respond and restore the electrical infrastructure.

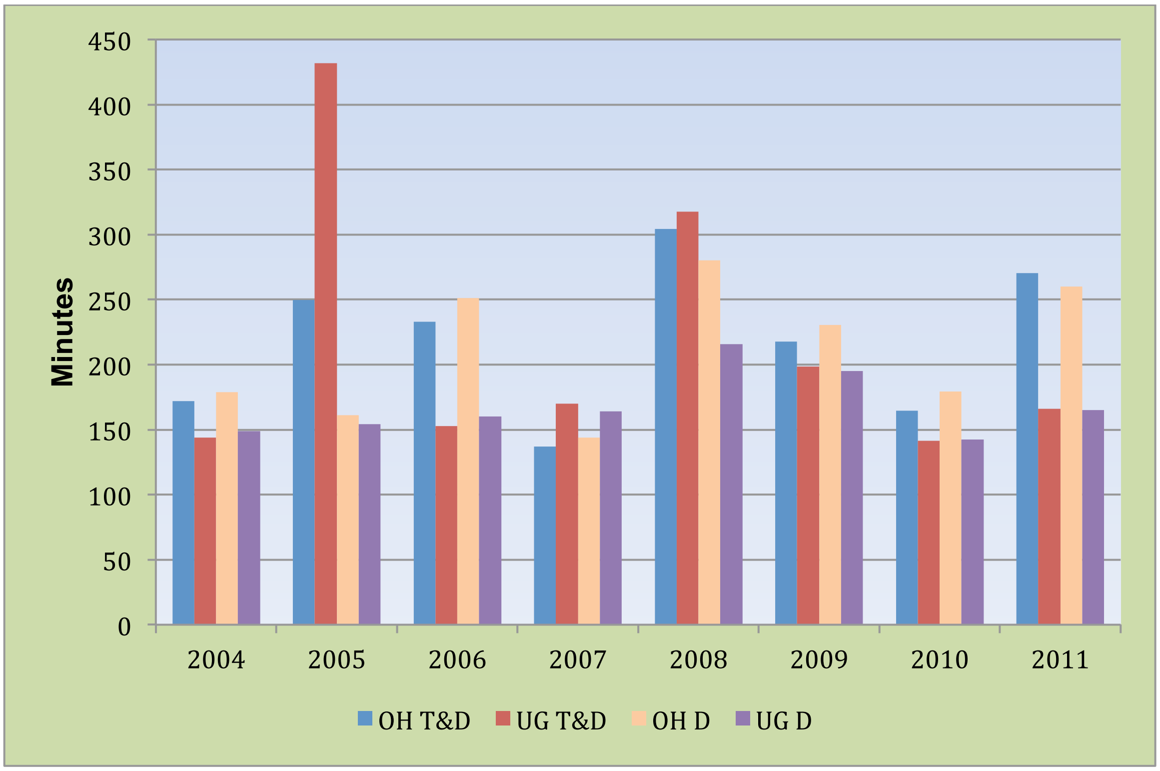
In comparing reliability data of overhead and underground infrastructure, it is worth noting that the overhead and underground elements of a utility electrical system are not always independent of each other. A large portion of underground facilities are served from an overhead feeder. Thus it is difficult to completely isolate the impact of an overhead outage from the underground system or vice versa.

There are many different reliability indices that can be used for comparison. For this report, EEI chose to gather data from three of the most used indices: CAIDI, SAIDI, and SAIFI. The information presented in the following figures represents the average of the data provided from the participating utilities for these indices.

Customer Average Interruption Duration Index (CAIDI)

CAIDI is defined as the average length of an interruption experienced by an interrupted customer, measured in "minutes." In this index, a customer can be counted as many times as they experience an outage. Figure 3.1, Customer Average Interruption Duration Index, presents the average CAIDI value for 2004 to 2011, for transmission and distribution combined, and distribution alone. The data demonstrates that the underground system has a slight advantage over the overhead system in five of eight years for the combined T&D reporting and seven of eight years for the D only data.

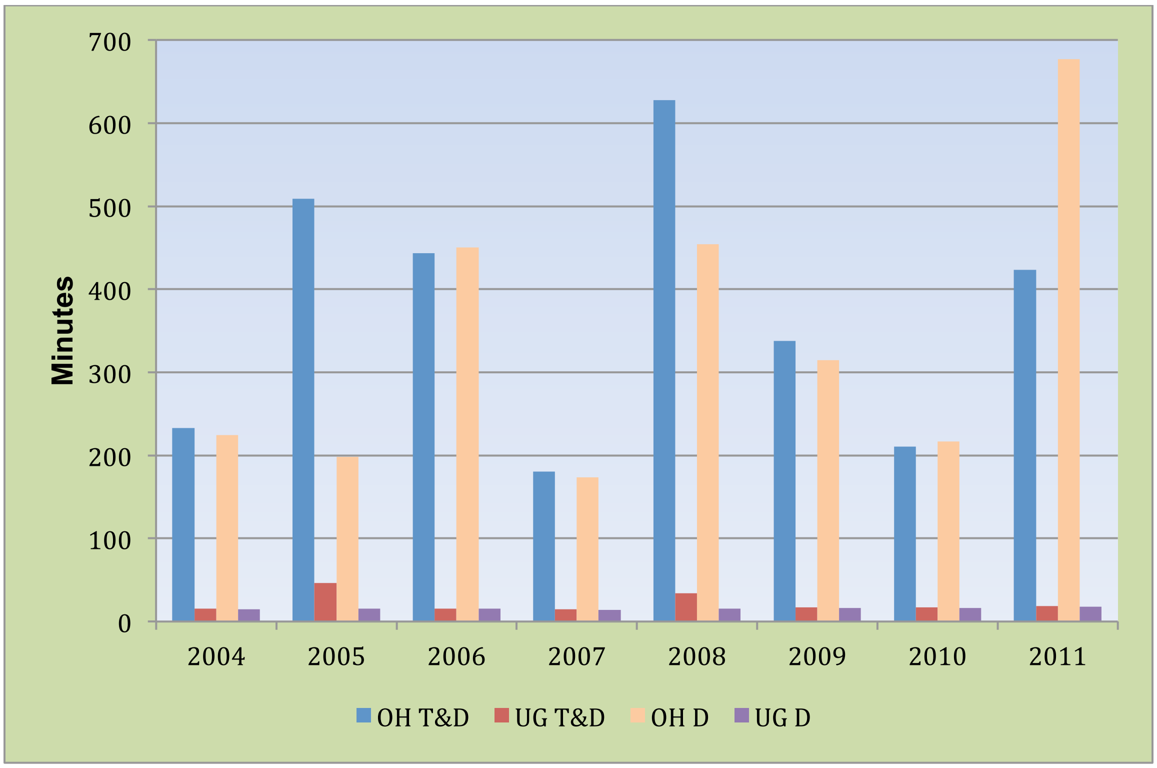
Figure 3.1 Customer Average Interruption Duration Index



System Average Interruption Duration Index (SAIDI)

SAIDI is defined as the average length of an interruption experienced by the average customer, measured in "minutes." In this index, each customer is only counted once and all customers are included in the calculation event even if they don't experience an outage. Figure 3.2, System Average Interruption Duration Index, presents the average SAIDI value for 2004 to 2011, for transmission and distribution combined, and distribution alone. This data set demonstrated that the average customer experienced significantly fewer minutes of outage from underground system outage events each year.

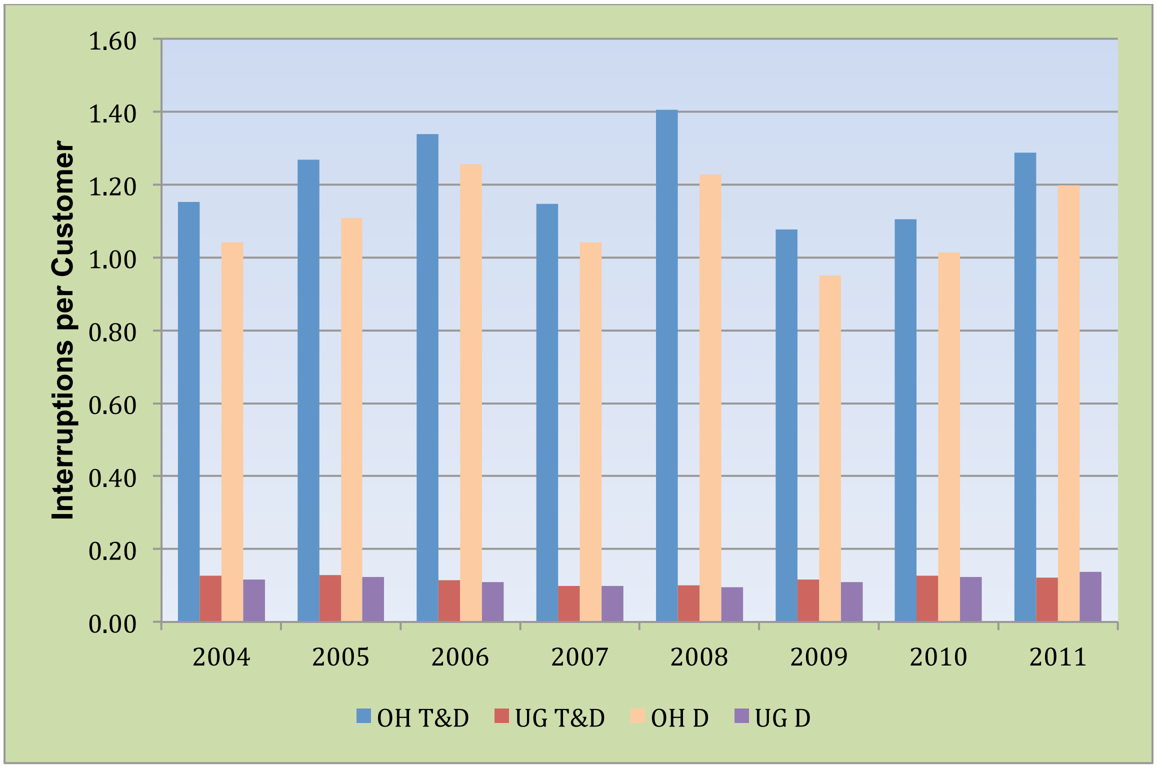
Figure 3.2 System Average Interruption Duration Index



System Average Interruption Frequency Index (SAIFI)

SAIFI is defined as the number of sustained interruptions the average customer experiences, measured in "interruptions per customer." Figure 3.3, System Average Interruption Frequency Index, presents the average SAIFI values for 2004 to 2011, for transmission and distribution combined, and distribution alone. In this data set, the underground electrical system is shown to contribute significantly fewer interruptions to the average customer outage experience.

Figure 3.3 System Average Interruption Frequency Index



From the data in the three previous charts, it is apparent that the underground electrical system contributes a smaller percentage to the overall outage numbers experienced by customers. But because parts of the underground systems are supplied by overhead systems, it is not conclusive if underground customers consistently experience a higher level of system reliability from a national average perspective.

Chapter 4: Utility Infrastructure

One objective in the 2012 *Out of Sight, Out of Mind* report is to demonstrate that utilities are investing significant resources and efforts into increasing the quantity of underground facilities.

System Growth

In the 2009 report, data was presented that compiled available information regarding the miles of installed overhead and underground circuits. This type of information was again considered for this report, but after reviewing the available source data, it has been determined that miles-of-line reporting was not consistent enough from year to year to be useful in presenting a clear discussion on the topic.

In Table 4.1, Transmission and Distribution Percentage Growth, utilities that participated in the EEI survey for this edition of the report provided information regarding the miles-of-line for their systems. The data that was collected was used to calculate an approximate annual percentage growth rate for the miles-of-line for overhead and underground facilities for the years between 2009 and 2011. In each of the cases presented below, the growth rate is less than 1 percent per year for either overhead or underground facilities. The data indicated that growth rate and additional miles-of-line built was greater for both transmission and distribution underground facilities.

Table 4.1 Transmission and Distribution Percentage Growth

	Transmission		Distribution	
	OH	UG	OH	UG
2009−2010	0.23%	0.76%	0.25%	0.45%
2010−2011	0.53%	0.80%	0.05%	0.39%

New Facilities Expenditures

More complete and consistent data is available from the U.S. Federal Energy Regulatory Commission (FERC) Form 1 on annual utility expenditures. This report reviewed the data on the amount of dollars spent on underground utility facilities. The following charts present data for the years from 1999 to 2011.

Figure 4.1, Total Transmission Expenditures, shows a steady increase in spending for overhead transmission over the last 13 years. The underground expenditures also show a positive trend over this 13-year period, but with a greater fluctuation over the last seven years.

Figure 4.1 Total Transmission Expenditures

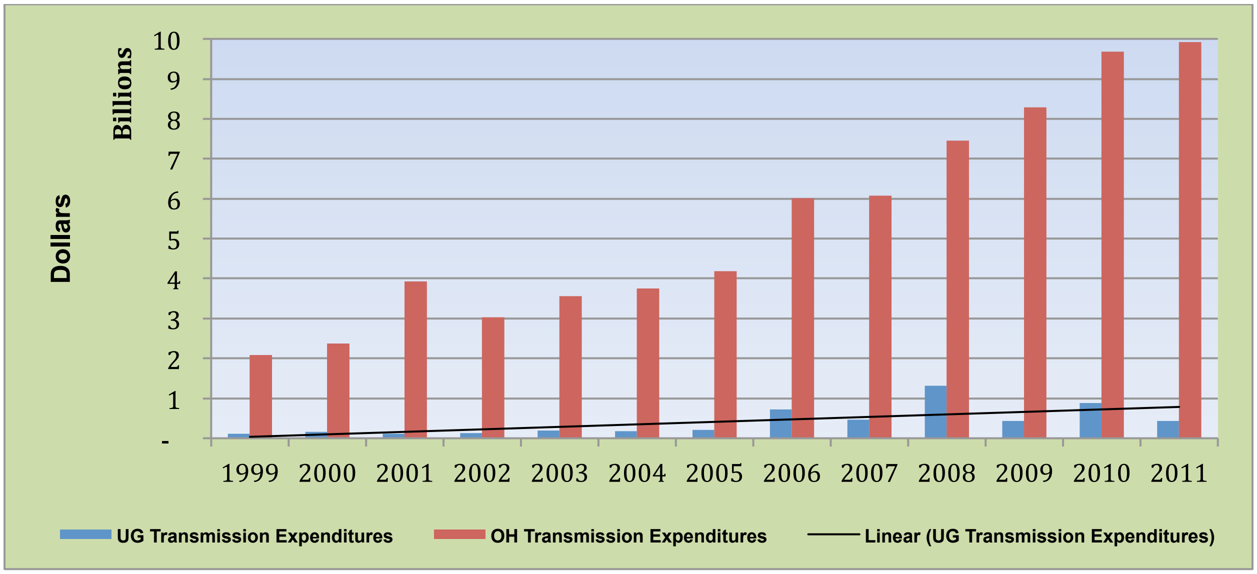


Figure 4.2, Total Distribution Expenditures, shows a steady increase in spending for overhead distribution until 2008, where it flattens out. The underground expenditures demonstrate a positive trend over this 13-year period, but with a slight decline in the last three years. Because much of the electrical distribution system growth is driven by the construction market, a downward trend is not unexpected due to the recession the U.S. economy.

Figure 4.2 Total Distribution Expenditures

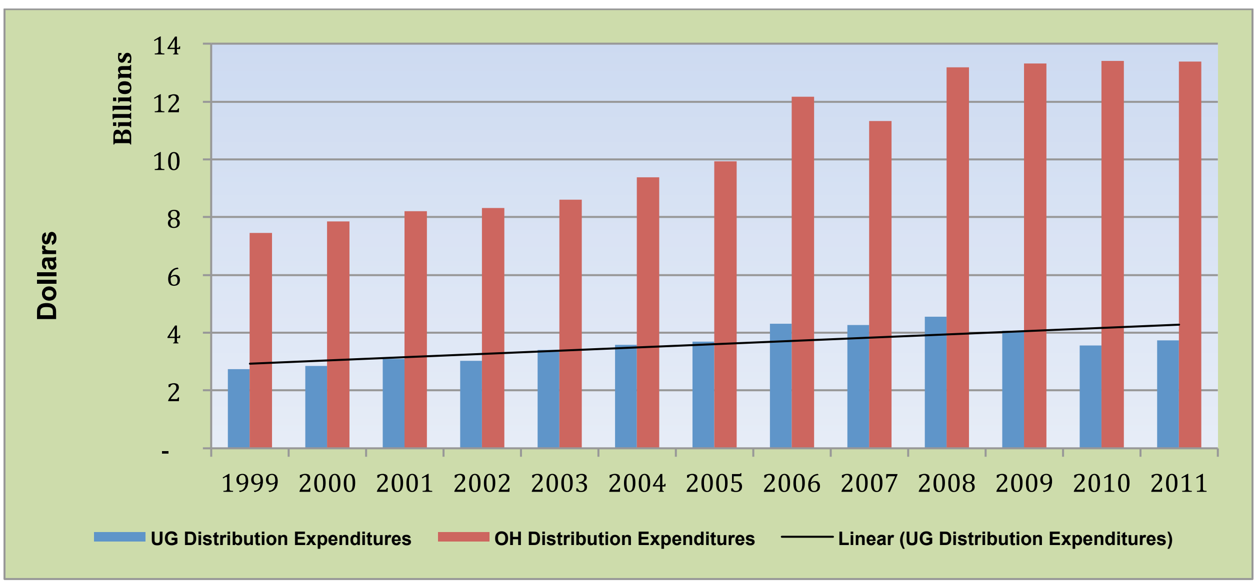
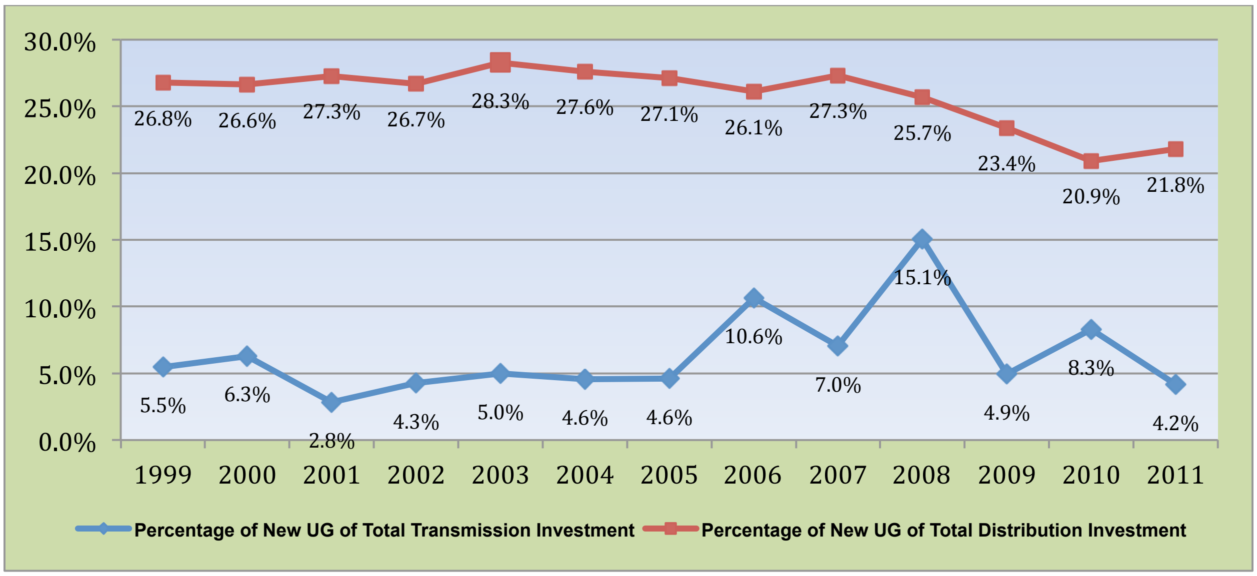


Figure 4.3, Percentages of Underground Investment, presents the annual percentage of total dollars spent on underground facilities out of all the dollars spent either on transmission or distribution. For transmission, this rate has varied from a low of 2.8 percent in 2001, to a high of 15.1 percent in 2008. For distribution, this rate has varied from a low of 20.9 percent in 2010, to a high of 28.3 percent in 2003. The distribution rate had been consistently above 25 percent until the late 2000s. This drop in spending is most likely the result of the U.S. recession and the falling demand for new construction starts.

Figure 4.3 Percentages of Underground Investment



From the available data, it is apparent that the underground electrical facilities are being installed at a faster pace than the overhead facilities. This demonstrates that utilities support the growth of underground facilities by investing resources to continue their construction.

Chapter 5: Benefits and Challenges of Undergrounding

Benefits of Undergrounding

To begin to understand the benefits derived from placing electrical infrastructure underground, it is useful to understand the perspective and experiences of how utilities perceive the value and the issues associated with underground facilities. In the 2012 survey, utilities were asked "What benefits does your utility derive from your underground system?". Their answers clearly reflected a perceived value, with examples including improved reliability, improved system performance, more effective routing of multiple feeders in confined areas, and in the enhancement of the visual aesthetics of roadways and streets in residential and business communities. The following is a summary of utilities' responses.

Reliability

- Benefits such as robustness to most weather events and less exposure to wildlife
- Increased reliability during high winds and storms
- Reduced exposure to lightning
- Reduced exposure to outages caused by trees
- Better voltage support
- Decreased tree trimming costs
- Newer UG cable systems, in general, tend to be more reliable and require less maintenance than OH installations
- In very dense urban areas, overhead construction becomes impractical, so the utility benefits by having the option of installing underground network systems in these areas where overhead can't be installed

Aesthetics

- Customers prefer underground construction
- Easier to obtain an easement for underground lines
- Helps with public image
- The primary benefit to an electric utility for an underground system is customer satisfaction
- One of the major benefits is to help create positive community relations by mitigating visual impact

Other

- Transmission─less public EMF concerns
- Transmission─fewer maintenance repairs
- Reduced congestion in high density areas
- Ability to maintain facilities at ground level, rather than from poles and bucket trucks
- Better public safety

- Lower feeder energy losses
- The cost of tree maintenance is removed entirely during the life of underground facilities
- Reduced route congestion near substations
- Increased customer acceptance for new projects
- Less resistance from towns for project approvals
- Significant reduction in right-of-way (R/W) maintenance costs and vehicular caused outages

Challenges of Undergrounding

In presenting and reviewing the challenges of undergrounding electrical systems, it is worth reiterating that underground utility systems take longer and cost more, both to install and to repair. Utilities do seek to provide the best service at the lowest cost; however, from a cost perspective, placing infrastructure underground seems to go counter to this basic objective.

The 2012 EEI survey identified several other disadvantages of having power lines and other equipment underground. In addition to higher costs for underground facilities, disadvantages include longer repair times, difficulty making system changes or upgrades, and damage from dig-ins.

The following list is a summary of the survey responses to the question "What issues and/or problems do your utility address because of your underground system?"

Costs

- Underground systems are normally more expensive to install than overhead systems
- Higher facility replacement costs
- Increased project costs associated with UG systems
- Increased material costs and longer installation timeframes vs. overhead
- Design redundancy/significantly higher capital costs for installation
- Higher operations and maintenance (O&M) cost offsets corresponding reduction in R/W maintenance costs
- Geographic areas with severe frost and rocky conditions can increase costs significantly
- Underground cable mitigation tends to be very expensive compared to other types of equipment repairs/replacements. This is due to the labor intensive nature of locating faults and repairing cable, the need for specialty contractors for replacement or mitigation work, and the need for additional crew resources to restore customers' power when a failure occurs.

Operation and Maintenance

- Older cables are more likely to fail and older tile or fiber duct systems are more likely to collapse when failed cable is pulled
- Repair times for UG construction are substantially higher than for OH construction, driving up maintenance costs and duration-based reliability indices
- Underground facilities experience many dig-ins by those who do not follow proper procedures to identify the location of underground facilities before excavating

- More complex operational needs, such as visual inspection, is impossible, making it more difficult and costly to maintain and repair
- Difficult repair due to frozen ground
- Difficult access for outage restoration in heavy snow areas
- Underground facilities are susceptible to flooding.
- Installation of underground services requires much more coordination between the utility and customer than similar overhead service installations
- Although UG construction eliminates some outage causes, UG systems are still vulnerable to lightning and equipment failure
- Difficulty locating space for padmounted gear
- Increased stray voltage concerns
- Specialized training/equipment for manhole/vault access
- Surface-mounted equipment inspections critical to protect public

Failure Issues

- Much of the cable installed in the 1970s and 1980s is reaching the end of its useful life, creating a peak in the need for infrastructure investment
- Customer satisfaction is at risk due to the connected nature of UG feeds. Multiple failures in a segment on a single tap interrupt power to the same set of customers. Customers often become frustrated since it is not visually apparent as to the cause/location and because failures often occur under warm, dry conditions.
- Power outages last longer because damage is more difficult to locate and takes longer to repair
- Outages involving the underground system take more time to resolve as faulted cable/equipment takes more time to locate and subsequently replace
- Customer perception that undergrounding their service or neighborhood should dramatically improve their reliability, not taking into account exposure of overhead portions of the system upstream

Other

- Submersible transformers, in particular, have created a significant safety hazard for crews attempting to locate and repair failed equipment
- Conflicts with other subsurface construction and utilities
- More specialized skillset and equipment required for installation and repairs

Conflict between Benefits and Challenges

One apparent conflict between the benefits and challenges associated with underground facilities is “improved reliability” and “longer restoration times.” On the surface it would appear that these two factors are mutually exclusive, i.e., they cannot both be true for the same underground system. To understand how both of these statements are true, we must take into account some of the differences in typical overhead and underground system construction and operations. Consider, for example, the scenario of how a small subdivision would be served with an overhead or underground electrical system.

Typical service for a subdivision served by an overhead configuration would consist of the construction of a signal phase line tapped off the main feeder circuit, with a fused cutout as a disconnect point. This tap line would be a radial line that did not connect back to the main circuit, but came to a dead end in the subdivision. Any type of fault on this line would cause the fuse to blow and would require utility personnel to restore service to the subdivision. In this configuration, the entire subdivision would be out of service until the problem was fixed.

If the subdivision was served with a typical underground configuration, the construction technique would require the underground line tapping off the main feeder to be looped through the subdivision and connected back to the main feeder at another tap point. This underground loop would have two feeds with an open point in the middle line, most likely at a transformer. In the case of a fault in this system, only one of the two tap fuses would blow, limiting the outage to only part of the subdivision. When utility personnel respond to this outage, they would seek to identify the problem area on the circuit, then isolate this problem area, and reconnect as much of the loop as possible with the problem area de-energized.

The underground system has built-in flexibility that allows the utility to restore most, if not all, of the customers' service before repairing the problem which caused the outage. The overhead system requires the problem to be repaired before service is restored; for an overhead system, this can be a relatively quick process because the problem can be visually identified and accessed easily. For the underground problem, a line fault may be easily identified between two transformer locations, but pinpointing the exact location can be time-consuming. The utility will have to determine if they can repair the problem or whether equipment or cable must be replaced. Consequently, this takes significantly more time than an overhead repair.

Chapter 6: Undergrounding Costs

The economics of undergrounding utility infrastructure has always been the overarching challenge for the utility and its customers who wanted lines put underground. If the cost of undergrounding were nearly the same as overhead construction, the decision would be easy, but that is not the case.

The 2012 EEI survey also collected data on the estimated cost per mile for new overhead construction, new underground construction, and the cost to convert from overhead to underground. The survey collected data on the percentage breakdown of these costs between material and labor to determine if underground construction is a more labor intensive and costly process.

Collecting data and comparing costs from across the country presents many challenges. First, it should be noted that all of these costs are high-level estimates based on averages or a utility's typical construction approach. There are many different variables to contend with, including customer density (urban, suburban, and rural), soil conditions (sandy to rocky), labor costs, construction techniques, vegetation, and voltage levels. This report has attempted to handle these variables in two ways, as follows:

First, data has been collected based on customer density, defined as:
- Urban─150+ customers per square mile
- Suburban─51 to 149 customers per square mile
- Rural─50 or fewer customers per square mile

Second, the report seeks to identify the range of costs for each category discussed, identifying the highest and lowest estimated costs in each category.

In addition to the challenges noted above for the data collected for this edition of the report, there is also some difficulty comparing data between the previous editions of the *Out of Sight, Out of Mind* reports. Several companies participating in each report have been different, leading to variances between high and low values within each of the data sets and the ratios between overhead and underground values in the comparisons. In this edition, very few utilities from high cost areas of the country provided data for this report. This could give the false impression that the cost of underground construction and the cost of conversions from overhead to underground are much less than it actually is compared to other areas of the country.

Because each construction project is unique due to load, number of customers served, and various construction parameters, there is no precise cost per mile to build utility facilities of any type for any utility. The cost data in this report is not meant to be the absolute range in which utility construction costs must fall; rather, it is intended to provide a range of cost data that utilities have estimated on various projects. Also, because of the complexity of calculations involved with these costs, they are not typically updated frequently.

Since the previous edition of this report, the cost of building electrical facilities has increased in all locations and construction categories.

Transmission Costs

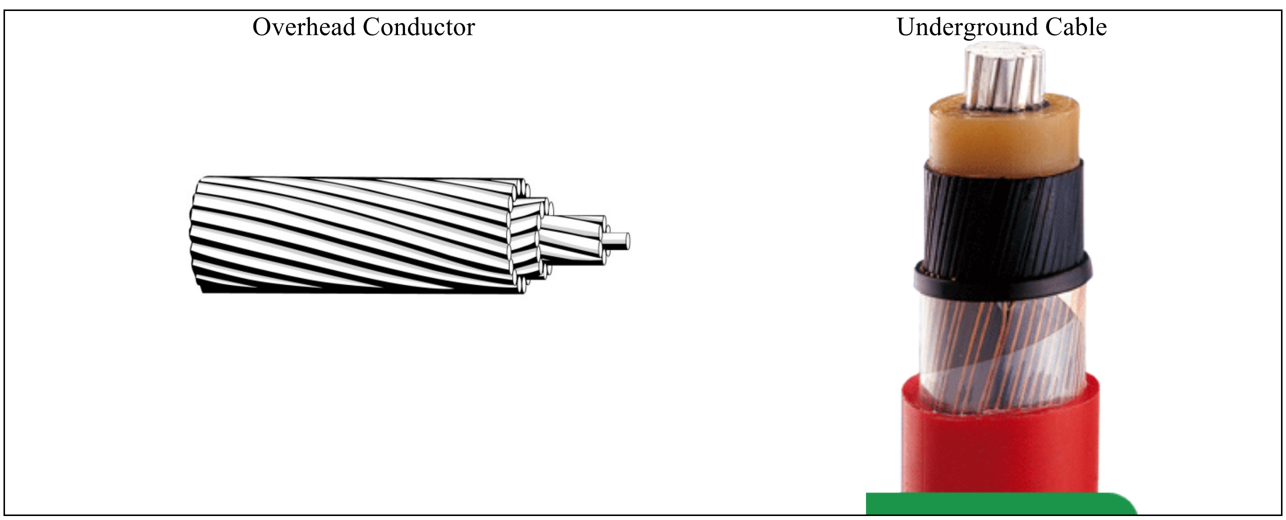
Table 6.1, Cost per Mile: New Construction Transmission, presents a range of costs for new construction of transmission. Overhead costs range from $174,000 per mile (for rural construction) to $11 million per mile (for urban construction). Likewise, underground costs range from $1,400,000 per mile (for rural construction) to $30 million per mile (for urban construction). This data shows a cost increase for both the high and low values as compared to the 2009 report. In the 2009 report, the underground range was from $1 to $23 million. When comparing data provided for transmission construction, remember that the construction requirements associated with different voltage levels contribute greatly to the cost variations. Higher voltage transmission lines require larger poles/towers and greater insulation levels in order to transmit electricity. All of these items contribute to the higher costs.

Table 6.1 Cost per Mile: New Construction Transmission

	Overhead			Underground		
	Urban	Suburban	Rural	Urban	Suburban	Rural
Minimum	$377,000	$232,000	$174,000	$3,500,000	$2,300,000	$1,400,000
Maximum	$11,000,000	$4,500,000	$6,500,000	$30,000,000	$30,000,000	$27,000,000

A simple visual example of the complexity of the underground cable compared to the overhead wire is the conductor used to transmit electricity. Figure 6.2, Utility Cables, shows an example of an overhead conductor and an underground cable. By simple inspection, it is easy to see how the construction of the underground cable is much more complex than the overhead. Consequently, this complexity results in a much more expensive component.

Figure 6.1 Utility Cables



Distribution Cost

Table 6.2, Cost per Mile: New Construction Distribution, presents a range of costs for new construction of distribution. Overhead costs range from $86,700 per mile (for rural construction) to $1 million per mile (for urban construction). Likewise, underground costs range from $297,200 per mile (for rural construction) to

$4.5 million per mile (for urban construction). This data shows a cost increase for both the high and low values as compared to the 2009 report. In the 2009 report, the underground range was from $63,000 to $2,074,000. For overhead distribution, voltage levels do not contribute as greatly to the variation in costs as compared to transmission lines. The variation in costs from rural to urban is related to the need for a greater number of poles or manholes, transformers, and service drops per mile to serve a denser load. (Do not assume that the low end costs provided by some utilities can be replicated by every utility.)

Table 6.2 Cost per Mile: New Construction Distribution

	Overhead			Underground		
	Urban	Suburban	Rural	Urban	Suburban	Rural
Minimum	$126,900	$110,800	$86,700	$1,141,300	$528,000	$297,200
Maximum	$1,000,000	$908,000	$903,000	$4,500,000	$2,300,000	$1,840,000

Conversion Cost

Table 6.3, Cost per Mile: Converting Overhead to Underground Transmission, presents a range of costs for converting overhead transmission electrical facilities to underground facilities. The conversion costs ranged from $1.1 million per mile for rural construction, to $12 million per mile for urban construction. In the 2009 report, transmission conversions were not discussed. The conversion costs may not appear to differ much from the cost of new underground distribution construction; however, the salvage value of the overhead system that would be removed during a conversion can offset some of the conversion costs.

Table 6.3 Cost per Mile: Converting Overhead to Underground Transmission

	Urban	Suburban	Rural
Minimum	$536,760	$1,100,000	$1,100,000
Maximum	$12,000,000	$11,000,000	$6,000,000

Table 6.4, Cost per Mile: Converting Overhead to Underground Distribution, presents a range of costs for converting overhead distribution electrical facilities to underground facilities. The conversion costs ranged from $93,000 per mile for rural construction, to $5 million per mile for urban construction. This cost has increased compared to the range of $80,000 to $2,130,000 from the 2009 report. Here, too, the salvage value of the overhead system that would be removed during a conversion offsets the conversion costs.

Table 6.4 Cost per Mile: Converting Overhead to Underground Distribution

	Urban	Suburban	Rural
Minimum	$1,000,000	$313,600	$158,100
Maximum	$5,000,000	$2,420,000	$1,960,000

Customer Conversion Cost

One component that is not always discussed in the conversion process is the direct cost that individual customers must pay to have their electrical service connection point converted. For most customers, a conversion will require them to hire an electrician to replace the overhead meter base with an underground meter base. In some cases, additional work may be required to bring the customer's service up to the current electrical code requirements.

Table 6.5, State Reports Conversion Cost Comparison, provides a comparison of the conversion cost data collected by the EEI 2009 and 2012 surveys and data collected by various state studies. The states conducting each study and the year the study was published are listed in the table; more information about each study can be found in Chapter 8. All values from the other studies fall within minimum and maximum values of the EEI data.

Table 6.5 State Reports Conversion Cost Comparison

State, Year of Study	Estimate / Actual Cost	Project Information	Cost per Mile
EEI, 2009	Estimate	Minimum Cost	$80,000
North Carolina, 2003	Estimate	Minimum Cost	$151,000
EEI, 2012	Estimate	Minimum Cost	$158,100
Maryland, 1999	Estimate	Minimum Cost	$350,000
Florida, 2007	Actual	Allison Island	$414,802
Florida, 2007	Actual	County Road 30A	$883,470
Florida, 2007	Actual	Sand Key	$917,532
Virginia, 2005	Estimate	Average Cost	$1,195,000
Oklahoma, 2008	Estimate	Average Cost	$1,540,000
Florida, 2007	Actual	Pensacola Beach	$1,686,275
Maryland, 1999	Estimate	Maximum Cost	$2,000,000
EEI, 2009	Estimate	Maximum Cost	$2,130,000
North Carolina, 2003	Estimate	Maximum Cost	$3,000,000
District of Columbia, 2010	Estimate	Maximum Cost	$3,500,000
EEI, 2012	Estimate	Maximum Cost	$5,000,000

Labor and Material Costs

For the 2012 report, EEI investigated whether there was a significant difference in the proportion of labor costs for underground construction as compared to overhead construction. The data indicates that the percentage of material costs increased in each category from the 2009 EEI report in a range of three to 12 points. In addition, except for underground transmission, construction labor contributes a little over 50 percent of the total cost in all the other categories.

Table 6.6, Material and Labor Percentages, demonstrates how costs for new construction are broken down between material and labor percentages. These are average values from the data collected by the 2012 EEI survey. It could be assumed that underground construction labor costs are the cause for the higher underground costs, but the data indicates this is not the case. The relative cost breakdown between labor and material for distribution, on average, is very close. For transmission, the percentages are reversed because of the higher underground material costs.

Table 6.6 Material and Labor Percentages

	Transmission		Distribution	
	Overhead	Underground	Overhead	Underground
Material	46.3%	53.5%	43.4%	45.9%
Labor	53.7%	46.5%	56.6%	54.1%

Chapter 7: State Policies and Utility Approaches to Undergrounding

Utility Policies for New Underground Construction

For nearly all new residential and commercial developments, it has become the electric industry's standard to provide underground electrical service. Also, for new stand-alone customers, utilities will typically provide underground services as an option. Regardless of whether the new customer is part of a development, a stand-alone customer, or in a high density urban setting, there is typically a cost associated with new underground electrical service.

Utilities recover undergrounding costs in basically two ways: either by incorporating the cost into the basic utility electric rate or by charging a connection fee for underground service. There are some variations for these undergrounding fees:

- Rate base approach─In high density, urban settings where standard utility construction is underground (i.e., New York City), the cost for undergrounding is part of the basic electrical rate that the customer pays each month. In these locations, the electric rates are higher to compensate for the higher cost of the underground electrical network.
- Cost difference approach─The typical approach that utilities use to calculate customer charges for providing underground service is to determine the cost difference between typical overhead construction and underground construction. Customers, or in many cases the builder/developer, have to pay these fees before utility construction will begin.
- First few feet free─A common variation of the cost difference approach is to provide the first few hundred feet of underground service at no additional charge to the customer. In cases where the distance from existing utility facilities exceeds the free distance, the customer would be charged the cost difference between typical overhead construction and underground construction for the additional distance.

Appendix B provides an overview of different company policies for new underground construction for 14 utilities that provided feedback to the EEI survey.

Utility Policies for Converting Existing Overhead Facilities to Underground

All utilities have policies and procedures for the conversion of overhead facilities to underground facilities. In nearly all cases, there are associated fees for the conversion. For most utilities, the conversion charges that customers are required to pay is equal to the cost of installing the underground electrical system, plus the cost of removing the overhead electrical system, minus the salvaged value of the removed overhead facilities. In nearly all conversion situations, customers are responsible for the labor and costs for converting their electrical service facility (meter base and service connection point) from overhead to underground.

Some utilities have special policies for conversion requests from municipalities. In high density urban areas where electrical load is high, utilities and municipalities may work together to offset some costs of the conversion (with the city providing land and space for underground utility facilities). Cities may also provide trenching and conduits for cables and vaults for transformers to help defray some of the undergrounding costs.

Some state utility commissions have set rules in place (e.g., California Rule 20) that dictate a process by which municipalities and utilities work together to identify a limited number of facilities that can be converted to underground each year. Once the conversion is completed, the associated cost is added to the utilities' rate base.

Other utilities are running pilot projects. For example, Duke Energy Carolinas will work with municipalities to place qualifying areas underground. The expenses for these conversion projects are funded by a Duke fund with municipality matching funds for up to 0.5 percent of Duke's taxable gross receipts from furnishing electricity within the municipality. Duke has indicated that very few municipalities have contacted them about this rate.

Appendix C provides an overview of different company policies for overhead to underground conversions for the utilities that provided feedback to the EEI survey.

Additional Policies

In the survey, EEI sought to determine if there were other policies that played a role in encouraging the conversion of overhead facilities to underground. EEI's survey asked the following additional questions:

- Are there special rate areas associated with these types of conversions?
- Does your public utility commission (PUC) have additional policies that you must comply with associated with converting existing overhead facilities to underground?

The overall responses to these questions were negative. No utility indicated that they had a special rate for overhead to underground conversion customers or that their PUCs had additional compliance policies.

Chapter 8: State Undergrounding Studies

Since 1999, an increasing number of state utility commissions have studied the possibility of mandating utilities to place all or part of their electrical facilities underground. Each study has been the result of a catastrophic weather event that left hundreds of thousands of customers without electrical service for many days. The general consensus from all of these studies has acknowledged that undergrounding the electrical infrastructure would have a positive impact on system reliability. The conclusion in every study, has determined that cost to achieve the desired underground system is considerably too expensive for either the utility or the electrical customers. Some of the key findings from these studies are shown below.

District of Columbia—The cost of undergrounding electrical facilities, depending on all or part of the facilities, would range between $1.1 to $5.8 billion dollars.

Florida—There is insufficient data to show that this high cost is 100 percent justifiable by quantifiable benefits such as reduced O&M cost savings and reduced hurricane damage.

Houston, Texas—The cost of undergrounding the existing distribution infrastructure is prohibitive. It would cost an estimated $35 billion to bury the cables of the entire regional distribution system.

North Carolina—Replacing the existing overhead distribution lines of the utilities with underground lines would be prohibitively expensive. Such an undertaking would cost approximately $41 billion, nearly six times the net book value of the utilities' current distribution assets, and would require approximately 25 years to complete. The ultimate impact on an average residential customer's bill would be an increase of more than 125 percent.

Oklahoma—Information gathered … clearly indicated that requiring electric utilities to underground all of their facilities is generally not a feasible solution. The cost to underground … would likely run into the billions of dollars, and the potential impact on customers would … approach thousands of dollars per customer.

Virginia—The cost associated with undergrounding was estimated to be over $80 billion. The resultant annualized revenue requirement on a per customer basis would be approximately $3,000. The potential benefits … resulting from the elimination of tree trimming maintenance, vehicle accidents, post storm restoration and lost sales during outages, do not appear to be sufficient to offset the initial construction costs.

Complete undergrounding of all electrical facilities is not the solution to the outage problems caused by storms. These studies have helped to identify ways of improving service reliability as state commissions are now working with their utilities to identify ways to harden the electric utility infrastructure, with the hope of reducing the ensuing outages caused by storms.

The executive summaries of the 11 state studies identified by this author are provided in Appendix D. Reports are listed in most recent chronological order.

Conclusion

What is the future for undergrounding? Although state commissions will continue to be pressured to study the feasibility of undergrounding electric facilities following major outage events, it is highly unlikely that any commission will ever mandate the complete undergrounding of any utility. No study has ever come close to showing an economic justification for undergrounding. However, that does not mean that utilities, customers, and commissions should not work together to develop undergrounding approaches where funding, resources, and support are available and in agreement to support undergrounding projects.

For customers, improved aesthetics and the hope that underground electrical facilities will provide greatly enhanced electric reliability will continue to be the driver for their desire for undergrounding of utility facilities. In this edition of *Out of Sight, Out of Mind 2012*, EEI and the author have included feedback from customers about their desire for undergrounding and their willingness to pay for such conversions. The customer responses were not surprising. Many were willing to pay a small additional fee for undergrounding but less than 10 percent were willing to pay double their current bill to pay for any conversion.

The available data has demonstrated that utilities are investing significantly in the construction of new underground facilities, spending over 4 percent of transmission dollars annually and over 20 percent of distribution dollars annually on underground construction.

This study has demonstrated that utilities see value in and are open to undergrounding their overhead facilities. However, the challenge for utilities and customers is the high cost for building new or converting existing facilities to an underground electrical system. The data has shown that underground versus overhead costs can be between five to 10 times greater for transmission and distribution construction.

Given the cost impact of converting existing overhead distribution facilities to underground and customer concerns about utility cost increases, a wholesale move to underground most existing utility distribution facilities is probably prohibitively expensive. However, a few states and utilities have developed policies and procedures designed to encourage the utility and the local municipality to work together to convert select overhead areas to underground.

The future of such conversions will hinge on the ability of customers, utilities and utility regulators to work together to find viable funding approaches that meet customer expectations and compensate utilities for the cost of placing electrical facilities underground.

Appendix A: EEI Out of Sight Out of Mind Survey

Welcome to the EEI Out of Sight, Out of Mind Survey. Data collected from this survey will be used in preparing the 4th update to the EEI Out of Sight, Out of Mind study.

The reliability data provided will be kept confidential and only averages and trends will be presented in the data presented in the report. If there is value in identifying a specific utility, permission will be obtained before inclusion. The final report will be available at no cost to survey participants.

To get started filling out the survey, please fill in the contact information below. You will then be given the choice to report at a holding company level or at an operating company level. To determine if you need to fill the survey out at the operating company level or at the holding company level and to review the survey questions prior to filling it out, please click **here** to view a blank copy of the survey.

Once you have completed and submitted the survey, you will be able to save a copy of your survey in PDF format.

We ask that you please try and complete the survey by Friday September 21, 2012.

If you have any questions about technical content of the survey please contact Ken Hall at khall@hallenergyconsulting.com or on (828) 627-2135.

If you have any questions about the survey tool please contact Steve Frauenheim at sfrauenheim@eei.org or on (202) 508-5580.

Please Provide Contact Information

First Name

Last Name

Title

Company Name

Phone Number

Email Address

Will you be completing the survey at the holding/company consolidated level or at the operating company level?

- (•) **Holding/Company Consolidated Level**
- ( ) **Operating Company Level**

Please select the Holding/Consolidated Company you are reporting for:

( ) AES Corp.	( ) Entergy Corp.	( ) Otter Tail Corp.
( ) Alaska Electric Light & Power Co.	( ) Exelon Corp.	( ) Pepco Holdings
( ) ALLETE	( ) FirstEnergy Corp.	( ) PG&E Corp.
( ) Alliant Energy Corp.	( ) Green Mountain Power Corp.	( ) Pinnacle West Capital Corp.
( ) Ameren Corp.	( ) Great Plains Energy	( ) PNM Resources

- American Electric Power Co.
- Avista Corp.
- MidAmerican Energy Holdings Co.
- Black Hills Corp.
- CenterPoint Energy
- Central Vermont Public Service Corp.
- CH Energy Group
- Cleco Corp.
- CMS Energy Corp.
- Consolidated Edison
- Dominion Resources
- DTE Energy Co.
- Duke Energy Corp.
- Edison International
- El Paso Electric Co.
- BHE Holdings (Bangor Hydro & Maine Public Service)
- Empire District Electric Co.
- Energy Future Holdings Corp.
- Iberdrola USA
- IDACORP
- Integrys Energy Group
- ITC Holdings Corp.
- Duquesne Light Holdings
- MDU Resources Group
- MGE Energy
- Mt Carmel Public Utility Co.
- National Grid USA
- NextEra Energy
- NiSource
- Northeast Utilities
- NorthWestern Corp.
- Northwestern Wisconsin Electric Co.
- NSTAR
- NV Energy
- OGE Energy Corp.
- Portland General Electric Co.
- PPL Corp.
- Public Service Enterprise Group
- Puget Energy
- SCANA Corp.
- Sempra Energy
- Southern Co.
- TECO Energy
- UGI Corp.
- UIL Holdings Corp.
- UniSource (UNS) Energy
- Unitil Corp.
- Vectren Corp.
- Vermont Electric
- Westar Energy
- Wisconsin Energy Corp.
- Xcel Energy

Please select all of the operating companies you are reporting for:

- AEP: AEP Texas Central
- AEP: AEP Texas North
- AEP: AEP Transmission Co.
- AEP: Appalachian Power Co.
- AEP: Columbus Southern Power Co.
- AEP: Indiana Michigan Power Co.
- AEP: Kentucky Power Co.
- AEP: Kingsport Power Co.
- AEP: Ohio Power Co.
- AEP: Public Service Co. of Oklahoma
- AEP: Southwestern Electric Power Co.
- AEP: Wheeling Power Co.
- AES Corp: Dayton Power & Light Co.
- AES Corp: Indianapolis Power & Light Co.
- ALLETE: Minnesota Power
- ALLETE: Superior Water Light & Power Co.
- Alliant Energy: Interstate Power & Light Co.
- Empire District Electric Co.
- Energy Future Holdings: Oncor Electric Delivery Co.
- Entergy Arkansas, Inc.
- Entergy Gulf States, Louisiana
- Entergy Louisiana, Inc.
- Entergy Mississippi, Inc.
- Entergy New Orleans, Inc.
- Entergy Texas
- Exelon: Commonwealth Edison Co.
- Exelon: PECO Energy Co.
- FirstEnergy: American Transmission System
- FirstEnergy: Cleveland Electric Illuminating Co.
- FirstEnergy: Jersey Central Power & Light
- FirstEnergy: Metropolitan Edison Co.
- FirstEnergy: Monongahela Power Co.
- FirstEnergy: Ohio Edison Co.
- FirstEnergy: PATH-AYE
- National Grid: Niagara Mohawk Power Corp.
- Next Era Energy: Florida Power & Light Co.
- NiSource Inc: Northern Indiana Public Service Co.
- Northeast Utilities: Connecticut Light & Power Co., The
- Northeast Utilities: Public Service Co. of New Hampshire
- Northeast Utilities: Western Massachusetts Electric Co.
- NorthWestern Corp.: Montana Operations
- NSTAR Electric
- NV Energy: Nevada Power Co.
- NV Energy: Sierra Pacific Power Co.
- OG&E Electric Services
- Otter Tail Power Co.
- Pepco Holdings: Atlantic City Electric Co.
- Pepco Holdings: Delmarva Power & Light Co.
- Pepco Holdings: Potomac Electric Power Co.
- PG&E: Pacific Gas & Electric Co.
- Pinnacle West: Arizona Public Service

- Alliant Energy: Wisconsin Power & Light Co.
- Ameren: Ameren Illinois
- Ameren: Ameren Missouri
- Ameren: Ameren Transmission Co.
- ATC: American Transmission Co.
- Avista Corp.
- BHE Holdings: Bangor Hydro-Electric
- BHE Holdings: Maine Public Service Co.
- Black Hills: Black Hills Colorado Electric
- Black Hills: Black Hills Power
- Black Hills: Cheyenne Light, Fuel & Power
- CenterPoint Energy Houston Electric, LLC
- Central Vermont Public Service Corp.
- CH Energy: Central Hudson Gas & Electric
- CLECO Power LLC
- CMS Energy: Consumers Energy
- ConEd: Consolidated Edison Co. of New York, Inc.
- ConEd: Orange & Rockland Utilities, Inc.
- ConEd: Pike County Light & Power Co.
- ConEd: Rockland Electric Co.
- Exelon Corp.: Baltimore Gas & Electric Co.
- Dominion: North Carolina Power
- Dominion: Virginia Power
- DTE Energy: Detroit Edison Co.
- Duke Energy Carolinas
- Duke Energy Indiana
- Duke Energy Kentucky
- Duke Energy Ohio
- Duquesne Light Co.
- Edison International: Southern California Edison
- El Paso Electric Co.
- FirstEnergy: Pennsylvania Electric Co.
- FirstEnergy: Pennsylvania Power Co.
- FirstEnergy: Potomac Edison Co.
- FirstEnergy: Toledo Edison Co.
- FirstEnergy: Trans-Allegheny Interstate Line Co.
- FirstEnergy: West Penn Power Co.
- Great Plains Energy: Kansas City Power & Light
- Great Plains Energy: KCP&L Greater Missouri Operating Co.
- Green Mountain Power Co.
- Hawaii Electric Light Co., Inc.
- Hawaiian Electric Co., Inc.
- Hawaiian Electric: Maui Electric Co., Ltd.
- Iberdrola US: Central Maine Power Co.
- Iberdrola US: New York State Electric & Gas Corp.
- Iberdrola US: Rochester Gas & Electric
- Idaho Power Co.
- Integrys Energy: Upper Peninsula Power Co.
- Integrys Energy: Wisconsin Public Service Corp.
- ITC Holdings: ITC Great Plains
- ITC Holdings: ITC Midwest
- ITC Holdings: ITC Transmission Co.
- ITC Holdings: Michigan Electric Transmission Co.
- Madison Gas & Electric Co.
- MDU Resources: Montana-Dakota Utilities Co.
- MidAmerican Energy Holdings: MidAmerican Energy
- MidAmerican Energy Holdings: PacifiCorp
- National Grid: Granite State Electric Co.
- National Grid: Massachusetts Electric Co.
- National Grid: Narragansett Electric Co.
- National Grid: New England Power Co.
- PNM Resources: Public Service Co. of New Mexico
- PNM Resources: Texas-New Mexico Power Co.
- Portland General Electric Co.
- PPL: Kentucky Utilities Co.
- PPL: Louisville Gas & Electric Co.
- PPL: PPL Electric Utilities
- Progress Energy: Progress Energy Carolinas
- Progress Energy: Progress Energy Florida
- PSEG: Public Service Electric & Gas Co.
- Puget Sound Energy
- SCANA Corp: South Carolina Electric & Gas Co.
- Sempra Energy: San Diego Gas & Electric Co.
- Southern: Alabama Power Co.
- Southern: Georgia Power Co.
- Southern: Gulf Power Co.
- Southern: Mississippi Power Co.
- TECO Energy: Tampa Electric Co.
- UGI Utilities
- UIL Holdings: United Illuminating Co.
- UniSource Energy: Tucson Electric
- UniSource Energy: UNS Electric
- UNITIL Corp.
- Vectren Corp: Southern Indiana Gas & Electric Co.
- Westar Energy
- Westar Energy: Kansas Gas & Electric Co.
- Wisconsin Energy: Wisconsin Electric Power Co.
- Xcel Energy: Northern States Power Co.
- Xcel Energy: Northern States Power Co.-WI
- Xcel Energy: Public Service Co. of Colorado
- Xcel Energy: Southwestern Public Service Co.

Survey Questions:

1. Number of Miles of Line:

	Overhead			Underground		
	2009	2010	2011	2009	2010	2011
Transmission						
Primary						
Secondary/Services						

2. CAIDI Reliability Data (minutes):

	Overhead			**Underground**		
	2009	2010	2011	2009	2010	2011
Transmission & Distribution						
Distribution only						

3. SAIDI Reliability Data (minutes):

	Overhead			Underground		
	2009	2010	2011	2009	2010	2011
Transmission & Distribution						
Distribution only						

4. SAIFI Reliability Data (minutes):

	Overhead			Underground		
	2009	2010	2011	2009	2010	2011
Transmission & Distribution						
Distribution only						

5. Total Annual Outage Minutes:

	Overhead			Underground		
	2009	2010	2011	2009	2010	2011
Outage Minutes						

6. Cost Per Mile--New Construction:

	Overhead			Underground		
	Urban (150+ cust/sq. mi.)	Suburban (51-149 cust/sq. mi.)	Rural (<51 cust/sq. mi.)	Urban (150+ cust/sq. mi.)	Suburban (51-149 cust/sq. mi.)	Rural (<51 cust/sq. mi.)
Transmission						
Primary						
Secondary/Services						

7. Cost Per Mile--New Construction (System Average)

	Overhead		Underground	
	% Material	% Labor	% Material	% Labor
Transmission				
Primary				
Secondary/Services				

8. Cost Per Mile Converting Overhead to Underground:

	Urban	Suburban	Rural
	(150+ cust/sq. mi.)	(51-149 cust/sq. mi.)	(<51 cust/sq. mi.)
Transmission			
Primary			
Secondary/Services			

9. What benefits does your utility derive from your underground system?

10. What issues and/or problems does your utility address because of your underground system?

11. What is your company's current policy for new underground construction? Has this changed since 2008? If so, please provide a copy or a link to this information.

12. What is your company's current policy for converting existing overhead facilities to underground? If so, please provide a copy or link to the information.

13. Are there special rate areas associated with these types of conversions? Has this changed since 2008? If so, please provide a copy or a link to the information.

14. Does your PUC have additional policies that you must comply with associated with converting existing overhead facilities to underground? Has this changed since 2008? If so, please provide a copy or a link to the information.

15. Has your PUC or state government published any studies or reports since 2007 addressing converting existing overhead facilities to underground? If so, please provide a copy or a link to this information.

Appendix B: Utility Policies for New Underground Construction

Ameren—Illinois

A single-phase overhead or underground Line Extension up to 250 feet, plus any necessary transformer and associated protective devices, may be provided free.
Customers extending from a Line Extension on which the Company is already holding a deposit will still be entitled to a free Line Extension. In addition, the Customer whose deposit is being held is still subject to refunds.
a) For Extensions greater than the free allowance, Customer will have the choice of the following two options:
(i) Refundable Deposit
The first option is for the Customer to provide a Refundable Deposit to pay for the cost of the Line Extension, calculated as the Standard Line Extension Refundable Cost per Foot, multiplied by the footage in excess of 250 feet.
(ii) Discounted Non-Refundable Contribution
The second option is for the Customer to provide a Non-Refundable Contribution to pay for the cost of the Line Extension, calculated as the Standard Line Extension Non-Refundable Cost per Foot, multiplied by the footage in excess of 250 feet. This amount provides a discount from the Standard Line Extension Refundable Cost per Foot by including a credit for an assumed additional Customer every 1,000'. Consequently, Customers choosing this option will not receive any refunds as additional Customers locate on the Extension.
b) All Refundable Deposits and Non-Refundable Contributions are to be paid by the Customer or Applicant prior to the start of construction.
c) Additional Options for Underground Line Extensions
The Customer may be allowed to furnish and install a conduit system on his premise or public right-of-way for either primary or secondary voltage cables. If primary/secondary conduit is installed by Customer, the Non-Refundable Contribution for the cable installation will be the Nonrefundable Cable in Conduit Installation Charge for any distance over the 250' allowance.

Allegheny Energy—Maryland, Pennsylvania, West Virginia, Virginia

Customer/Developer must provide all trenching conduit and backfill; with the exception of Lot Plans (5 or more lots) in VA (Allegheny Energy provides trenching, conduit and backfill per the VA Tariff Plan C).

Baltimore Gas & Electric—Maryland

Code of Maryland Regulations–20.85.01.01
A. An extensions of electric distribution lines on applicants' owned and leased properties, and in industrial parks, necessary to furnish permanent electric service to new commercial and industrial buildings, and to new multiple-occupancy buildings shall be made underground.
B. These regulations do not apply to extensions of lines of nominal 33,000 volts and higher.
C. The application of these regulations is not mandatory for extensions of lines to provide electric service to customers whose premises are so unaesthetic that the construction of underground lines would serve no purpose. Customers of this nature might include gravel pits and other mining operations, junk yards, railroad yards, and steel mills.

Central Hudson—New York

Underground Residential Distribution Systems in Subdivisions:
Any distribution line, service line and appurtenant facilities necessary to furnish permanent electric service to one or more multiple-occupancy dwellings (including four or more dwelling units) or within a residential subdivision in which it is planned to build five or more new residential buildings shall be installed underground if:

i. the residential subdivision will require no more than 200 trench feet of facilities per dwelling unit planned; or
ii. a governmental authority having jurisdiction to do so has required undergrounding; or
iii. the applicant requests undergrounding.

Connecticut Light & Power Company—Connecticut

Overhead construction is the standard with the exception of conventional underground construction in downtown city environments. However, nearly all municipalities require new residential and commercial developments to be underground construction. Private developers also have the choice to request underground construction. In all cases, the developer must pay the differential cost between underground construction and standard overhead construction. The regulatory commission does not dictate when extensions should be underground or overhead construction, but they do regulate the policy for determining the customer contribution.

Detroit Edison—Michigan

Existing rules issued by the Michigan Public Service Commission require that distribution systems in a new residential subdivision and commercial distribution and service lines in the vicinity of or on the customer's property and constructed solely to serve a customer or a group of adjacent customers be placed underground. The general policy of the Company is that real estate developers, property owners, or other applicants for underground service shall make a non-refundable contribution in aid of construction to the Company in an amount equal to the estimated difference in cost between underground and equivalent overhead facilities.

Duke Energy Carolinas—North Carolina, South Carolina

RESIDENTIAL SERVICE—At the request of an owner, the Company will install, own, and maintain underground facilities for service to single residences, apartments, condominiums, and manufactured homes following these Plan provisions. Any charge to the owner is for the cost difference of the necessary underground facilities requested and is nonrefundable. The signed agreement with the owner for underground service shall specify the payment arrangements.
Permanent Residences—Residences which are to be permanent customer locations on a residential rate schedule of the Company will be served from underground facilities as shown below.

1. New Service Installations Located in New Developments
    - Service to new residences on lots averaging an acre (43,560 sq. ft.), or less—No charge
    - Service to new residences on lots averaging more than one acre—No charge except for cost difference of new primary facilities exceeding 300’ per lot
2. New Service Installations Not Located in New Developments
    - Service to new residences requiring new underground secondary voltage facilities from an above-ground distribution line on, or adjacent to, the lot on which the residence is located—No charge
    - Service to new residences requiring new underground primary and secondary voltage facilities—No charge except for cost difference of new primary facilities exceeding 300’

3. New Three-Phase Service Installations
   - Three-phase service to new single-residence structures, where this type of service is available─No charge except for cost primary difference of new primary facilities exceeding 300’
   - Three-phase service to new multi-residence structures, where this type of service is available─No charge

NON-RESIDENTIAL SERVICE

At the request of an owner, the Company will install, own, and maintain underground facilities to new general service and industrial service installations following these Plan provisions. Any charge to the owner is for the cost difference of the necessary underground facilities requested and is non-refundable. The signed agreement with the owner for underground service shall specify the payment arrangements.

1. New Service Installations Requiring Only Secondary Voltage Facilities─No charge
2. New Service Installations Requiring Primary Voltage Loop System Facilities─No charge
3. New Service Installations Requiring Primary Voltage Radial Extension Facilities─No charge except for cost difference of single-phase primary facilities exceeding 300’, or three-phase primary facilities exceeding 500’. For three-phase primary facilities exceeding 500’, additional underground footage will be provided at no charge when installation of underground facilities is less than comparable overhead facilities.
4. New Bulk Feeder and Sub-feeders─Cost difference of such primary facilities

Entergy—Arkansas, Louisiana, Mississippi, Texas

Except for downtown network areas, the default system for new construction is overhead. The company generally requires payment of the installation cost difference between overhead and underground construction before underground will be installed.

Florida Power & Light—Florida

FPL's standard service is overhead service on wood poles (except for specific high load, high density areas such as downtown Miami, aka DUGA [Designated Underground Area]). In areas other than DUGA, if the applicant requests underground service, or if underground service is required by ordinance or deed restriction, the applicant is charged a contribution in aid of construction (CIAC) as required by Florida Administrative code 25-6.064.

Hawaiian Electric—Hawaii

The Company will install its distribution system underground only when the customer, developer, or sub-divider makes a contribution of the estimated difference between the cost of the underground system and an equivalent overhead system, or when for engineering and operating reasons the company may install the system underground at its own expense.

Louisville Gas & Electric/Kentucky Utilities—Kentucky

Underground Electric Distribution Systems for New Residential Customers

Installation of underground distribution system within new subdivision

(a) Where appropriate contractual arrangements have been made, the utility shall install within the subdivision an underground electric distribution system of sufficient capacity and suitable materials which, in its judgment, will assure that the property owners will receive safe and adequate electric service for the foreseeable future.

(b) Facilities required to be underground:

1. All single phase conductors installed by the utility shall be underground. Appurtenances such as transformers, pedestal-mounted terminals, switching equipment, and meter cabinets may be placed above ground.
2. Three (3) phase primary mains or feeders required within a subdivision to supply local distribution or to serve individual three (3) phase loads may be overhead unless underground is required by governmental authority or chosen by the applicant, in either of which case the differential cost of underground shall be borne by the applicant.

Customer pays the difference in cost between overhead and underground construction, less applicable credits for new line extensions.

Madison Gas & Electric—Wisconsin

All new urban construction is proposed to be underground. Rural distribution extensions are proposed overhead unless conditions dictate otherwise. All new services are proposed underground.

Minnesota Power—Minnesota

All new residential developments are served with underground facilities. All existing underground circuits remain underground if cables are replaced. Some areas where we are unable to obtain easements wide enough for overhead lines may be constructed underground.

Northeast Utilities—Connecticut

Customer pays for the difference in cost between overhead and underground.

NorthWestern Energy—Montana

The Utility will install underground distribution lines in new service areas of five (5) or more consumer units when undergrounding is technically feasible.
Upon application for electric service, the Utility shall make an electric line extension, including primary and secondary service lines to the applicant (except that the applicant shall furnish all necessary rights-of-way) as follows:
A. In the case of an application for residential service, a maximum free extension allowance of $500 plus the service drop (not to exceed 150 feet overhead or 100 feet underground), transformer, and meter.
B. In the case of an application for general service (GS), a maximum free extension allowance of:
1. GS non-demand metered service; $0.04/kWh times the Utility's estimate of the annual kWh consumption of the Customer plus the service drop (not to exceed 150 feet overhead or 100 feet underground), transformer, and meter;
2. GS demand metered less than 1 Mw; $0.04/kWh times the Utility's estimate of the annual kWh consumption of the Customer plus the service drop (not to exceed 150 feet overhead or 100 feet underground), transformer, and meter;
3. GS demand metered equal to or greater than 1 Mw; calculated based on the Revenue/Cost Ration described below;
4. Industrial Customers or projects requiring transmission or substation facilities; calculated based on the Revenue/Cost Ratio described below.
Revenue/Cost Ratio: The comparison between the expected annual revenue to be received from the Customer and the annual cost of serving the Customer. A Revenue/Cost Ration greater than one (1) will

result in some level of free extension cost allowance; a Ration less than or equal to one (1) will result in no free extension cost allowance.

Oncor Electric Delivery—Texas

Underground Extensions for Small Loads
Except in those areas where Network Service is the existing or planned service in use, Company makes extension of underground single phase electric service without charge to permanent Retail Customers having an estimated maximum annual demand of less than 20 kW if electric service desired by Retail Customer is of the type and character of electric service which Company provides, and if the cost of the extension does not exceed an amount equivalent to 300 feet of overhead radial single phase circuit. The cost of the extension is calculated using the route of the new line from Company’s existing distribution facilities, which includes primary, secondary, and Service Lateral to the point of delivery. When two or more applications for electric service from the same extension are received prior to starting construction of the line extension, the extension will be provided without charge if the total cost of the extension does not exceed an amount equal to the number of applicants times an amount equivalent to 300 feet of overhead radial circuit. Retail Customer makes a onetime non-refundable contribution in aid of construction for the cost of providing an extension in excess of such amount based upon a specific cost study.

Orange and Rockland Utilities—New Jersey, New York, Pennsylvania

(1) Allowance for Mandatory Residential Underground Service
Where the Company is required, by the Commission or a governmental authority having jurisdiction to do so, to provide residential underground service, the cost and expense which the Company must bear, except as otherwise provided in the Rules of the Public Service Commission parts 98, 99, and 100, or as set forth in General information Schedule 5 shall include the material and installation costs for up to a total of 100 feet of single phase underground distribution line (including supply line) and underground service line per dwelling unit served, measured from the Company's existing electric system (from the connection point on the bottom of the riser pole for overhead to underground connections) to each applicant's meter or point of attachment with respect to each residential building. For multiple occupancy buildings, the footage allowance for each building shall be up to 100 feet of single phase underground line times the average number of dwelling units per floor of each building. The average number of dwelling units per floor is calculated as follows: total # of units/# floors = number of allowances. If the Company receives an application for underground residential service outside a subdivision, and a governmental authority having jurisdiction to do so has required that the facilities be installed underground, the Company may, if the per-foot cost of installing the necessary facilities will be greater than two times the charges per foot set forth in General Information Schedule 3.H.2, petition the Secretary of the Commission to allow a greater contribution to the cost of installation of the facilities than would otherwise be required.
(2) Allowance for Non-Mandatory Residential Underground Service
Where an applicant requests a residential underground service line in situations other than those as set forth in paragraph (1) above, the cost and expense which the Company must bear shall include the material and installation costs for up to
500 or 300 feet of overhead distribution line, measured from the Company's existing electric system (from the connection point on the bottom of the riser pole for overhead to underground connections) to each applicant's meter or point of attachment with respect to each residential building.

PPL Electric Utilities—Pennsylvania

Transmission: PPL's current policy for new underground Transmission (69−138kV) has not changed much since 2008. PPL's standard practice utilizes a concrete encased duct and manhole system, typically with EPR or XLPE insulated copper or aluminum power cables. On double-circuit lines PPL uses a two manhole system to avoid having more than one circuit in a manhole.
Distribution:

- Primary─utilize preassembled cable in conduit. The Developer digs the trench and we install the cable in conduit.
- Secondary/services─customer is required to provide either schedule 40 PVC direct buried or flexible pipe. We expect the conduit to be pull-able and then we install the conductor.
- Commercial 3PH primary─customer installs concrete encased PVC, we pull cable into the conduit and terminate.
- Commercial 3PH secondary/service─customer installs concrete encased PVC, we pull cable into the conduit and terminate.
- Company installed UG (replacement of existing URD, substation getaways)─we use a combination of trenching and directional boring. Depending on the application, it may be preassembled cable in conduit, PVC conduit (direct buried or concrete encased), or direct buried cable.

Public Service of New Hampshire—New Hampshire

There is no company policy on what should be underground. However, PSNH does offer the option to customers/developers to locate their developments and services underground. Many communities in New Hampshire have town ordinances requiring underground construction for new residential and commercial developments. Costs in excess of overhead construction are borne by the developer/ customer.

Puget Sound Energy—Washington

Undergrounding is provided per jurisdictional requirements or when the customer makes a financial contribution towards project.

Southern California Edison—California

We are continuing to install new UG cable systems; however, we are attempting to pursue padmount installations instead of subsurface/vault installations.

Tucson Electric Power—Arizona

Per TEP's current Rules and Regulations on file with the Arizona Corporation Commission, underground line extensions will be made provided that the customer pays a non-refundable contribution in aid of construction equal to the differential cost of the underground construction compared to overhead construction.

We Energies—Michigan, Wisconsin

Underground construction is used for new subdivisions designs, where existing underground facilities exist, or when determined to be the best overall design in terms of expected reliability performance and life-cycle cost.

Western Massachusetts Electric—Massachusetts

Customers may request underground supply for new residential and commercial installations. The Customer would pay a differential average cost between overhead and underground construction and be required to install some infrastructure (i.e., conduits, transformer pads).

Xcel Energy—Colorado

All transmission construction is overhead unless a third party pays the difference in cost to place it underground. Transmission will be put underground if right-of-way cost makes UG less expensive. Distribution and secondary construction is overhead unless required in a franchise agreement or ordinance.

Appendix C: Utility Policies for Converting Existing Overhead Facilities to Underground

Ameren—Illinois

Existing Customers who are presently served by adequate electrical facilities, but request Company to relocate, convert, or in some other manner modify these facilities will reimburse the Company if Company, at its discretion, agrees to make the requested changes. At Company's discretion, such charges may be based on either actual costs or standard job estimation calculations incurred for such work.
When a relocation or modification is done in conjunction with other system expansion or excess facilities requested by Customer, all applicable provisions of each section shall apply. Types of modifications that may fall under this provision include, but are not limited to: 1. Overhead to underground or underground to overhead conversions.

Allegheny Energy—Maryland, Pennsylvania, West Virginia, Virginia

Customer pays for the cost of converting overhead facilities to underground. Customer must also perform trenching, provide conduit, and do all backfilling.

Baltimore Gas & Electric—Maryland

No set policy—done selectively on a case-by-case basis for reliability benefit or at customer request (cost reimbursable by customer).

Connecticut Light & Power Company—Connecticut

The standard primary design is overhead, open wire construction. Underground construction may be justified under the following circumstances: in urban areas, where no overhead facilities exist; in a defined new development or primary service; for highway or transmission line crossings; where outside agencies or parties are willing to pay the entire cost of undergrounding existing facilities.

1. A designated underground area is defined as an urban area, where no overhead facilities exist because of clearance problems, circuit congestion, or space limitations. A conventional duct/manhole system shall be used. Configurations of six ducts or 12 ducts shall be used based on the ultimate circuit loading in the immediate vicinity as well as consideration for circuits routed to adjacent areas. Consult DTR Section 73 for standard duct configurations.
2. In a new residential, commercial, or industrial development, where the developer is willing to pay the differential cost between overhead and underground service, direct buried construction shall be used. This includes primary services. However, in some instances, all or part of a development may require ducts and manholes due to poor backfill conditions or to multiplicity of circuits.
3. For highway and transmission line crossings, where overhead facilities are not feasible, underground cable in a duct or ducts is the preferred design. In these cases, at least one spare duct per cable should be included in the installation where practical. If cable length exceeds 500 feet, a spare cable should be installed with switching to allow its use quickly if full-load tie capability does not exist.
4. When the Company is requested by an outside agency or private party to place existing overhead facilities below grade, the following rules should apply: the minimum length to be considered is 1000 feet, unless contiguous with existing underground construction; the construction will be standard duct/manhole design,

utilizing a minimum of six 5″ concrete encased ducts and 5′ x 10′ manholes; if full-load tie capability does not exist beyond subject area then a second cable must be installed as a backup; if underground construction exists within 1000 feet on either side of proposed construction, then the new construction must be made contiguous with the existing construction.
These guidelines are designed to mitigate the negative effects of frequent changes from overhead to underground construction. All construction listed above shall be considered necessary and 100percent reimbursable. This guideline would also apply if below grade construction is requested on a new or existing through street when a line extension is required.

Detroit Edison—Michigan

The Company will not undertake the replacement of existing overhead lines and above-surface equipment with underground installations or provide underground installations for transmission lines, sub-transmission lines, distribution feeders, and above-surface electric equipment associated with switching stations except where agreements for reimbursement are made in accordance with MPSC R-460.516, "Replacement of Existing Overhead Facilities." The general policy of the Company is that real estate developers, property owners, or other applicants for underground service shall make a non-refundable contribution in aid of construction to the Company in an amount equal to the estimated difference in cost between underground and equivalent overhead facilities.

Duke Energy Carolinas—North Carolina, South Carolina

CONVERSION TO UNDERGROUND
The Company will replace an existing overhead distribution system with an underground system in an existing residential development or other area under the following terms and conditions:
1. The Company shall place facilities underground by an agreement with the requesting persons which provides for payment of a nonrefundable, contribution in aid of construction as follows:
a. When the existing overhead distribution system is not adequate to supply the customer's load due to added electrical load, the contribution in aid of construction shall be equal to the cost difference between comparable overhead and underground facilities.
b. When the existing overhead distribution system is adequate to supply the customer's load, the contribution in aid of construction shall be equal to the cost of comparable underground facilities, less any salvage value of the overhead system.
2. Preliminary engineering studies are necessary to determine the approximate costs of replacing overhead with underground facilities. Persons requesting replacement of such facilities shall pay, prior to commencement of such studies by the Company, a good faith, nonrefundable deposit in an amount of $100 for each 600' of front lot lines for residential development studies, and, for studies of all other service areas, the estimated cost of the preliminary engineering study. If the replacement is undertaken following completion of such studies, actual costs, including preliminary engineering studies, will be charged and credit will be given for the estimated costs, or deposit, which was advanced.
3. The Company need not replace existing overhead systems with underground facilities, except individual services from pole to residence, unless at least one block or 600' of front lot line is involved, whichever is less.
4. All customers served directly from the specific section of line or in the area to be replaced with underground facilities shall agree to the conditions outlined for replacement of overhead facilities.
5. Owners shall arrange the wiring of their structures to receive underground service at meter locations which allow unimpeded installation of the underground service facilities.

Overhead to Underground Conversion Plan for Municipalities— (Pilot)

AVAILABILITY—Available on an experimental basis, at the Company's option to up to three municipalities where Duke Energy Carolinas, LLC and the municipality have entered into a franchise agreement. The initial term of this pilot is three years.
GENERAL PROVISIONS—This program provides mechanism to defray the costs of converting overhead electric distribution facilities to underground facilities under the Company's Underground Distribution Installation Plan under the following provisions:

- Each participating municipality will enter into a separate agreement for service under this program which may be an addendum to, or incorporated into the franchise agreement.
- The cost of overhead conversion projects under this program shall be funded by a Company Fund and a Municipality Matching Fund whereby the Company and the municipality shall commit matching contributions up to 0.5 percent of the Company's taxable gross receipts from the business of furnishing electricity within the municipality.
- The Company Fund contributions shall be paid out on a one-to-one basis with the Municipality Matching Fund as needed to pay the reasonable and necessary costs of converting the Company's facilities from overhead to underground. The costs to be paid from this fund shall include planning, designing, and constructing the necessary Company facilities. The Company Fund and Municipality Matching Fund are not available for the costs of overhead to underground conversion of any other facilities (e.g. telecommunications, cable television) or the property owners' cost to connect to underground facilities.
- Municipalities shall, with input from the Company, establish priorities for overhead to underground conversion projects. Projects will be prioritized based on expected improvement in system service reliability and/or safety, and an expected accompanying reduction in operating and maintenance expense. Overhead to underground conversion projects for aesthetic reasons, or those associated with redevelopment efforts, are not eligible for the Company's matching funds under this program.
- Unexpended amounts of the Company's Match not used in a given year shall remain in the fund, and may be used prior to the end of the pilot.
- Overhead to underground facility conversions made under this program shall be made in accordance with all other provisions of the Company's Underground Distribution Installation Plan and the Company's design practices.
- The Company shall not begin construction of an overhead to underground conversion project under this program until the municipality's matching funds are received and all necessary permits and rights of way are provided.

Duke/Progress Energy Florida—Florida

Facilities are converted from OH to UG at the customer's request, in which they would incur the cost, or as identified for reliability improvement and funded by Storm Hardening.

Entergy—Arkansas, Louisiana, Mississippi, Texas

Generally, such conversions are only done at the request of a specific customer, and only after the customer pay the entire conversion cost.

Florida Power & Light—Florida

If an applicant requests that the existing overhead facilities be converted to underground, a contribution in aid of construction is charged as required by Florida Administrative code 25-6.115, as outlined in FPL's Electric Tariff sheets 6.300−6.330 (http://www.fpl.com/customer/rates_and_bill/rules_tariffs.shtml).

Hawaiian Electric—Hawaii

When mutually agreed upon by the customer or applicant and the Company, overhead facilities will be replaced with underground facilities, provided the customer or applicant requesting the change makes a contribution of the estimated cost installed of the underground facilities less the estimated net salvage of the overhead facilities removed.

Louisville Gas & Electric/Kentucky Utilities—Kentucky, Virginia

The customer pays the total conversion cost including design, installation of underground, and removal of existing overhead.

Madison Gas & Electric—Wisconsin

Overhead-to-underground conversion projects for reliability improvements are analyzed and completed. Request from municipalities for aesthetic improvements are entertained and compensable.

Minnesota Power—Minnesota

Some areas where vegetation control is difficult or where we do not have permission to trim or remove trees are converted to underground. We convert other overhead lines if requested by, and paid for by, a customer.

Northeast Utilities—Connecticut

At customer request, the customer pays.

NorthWestern Energy—Montana

When electric Customers request a conversion of existing overhead electrical facilities to underground facilities, Customer shall make a nonrefundable contribution to the Utility equal to the cost to the Utility of the underground installation after an allowance is made for the net salvage value of materials removed after deducting from such salvage the cost of removing the same. Whenever, under the provisions of this Rule, an advance or contribution is required, or a refund is made on any such advance or contribution, such advance contribution, or refund shall be increased by a factor of 30 percent. This increase is to offset the effect of income taxes imposed by the Tax Reform Act of 1986. This income tax surcharge is not applicable where such contributions or advances are the result of highway relocations.
It is NorthWestern Energy's policy to not place 161 kV and 230 kV transmission lines underground. The placement of 50 kV through 115 kV transmission lines underground will be considered on a case-by-case basis. Where requests for placing transmission facilities underground are made primarily for aesthetic reasons, the customer or requesting party will pay for the costs incurred to place the lines underground.

Oncor Electric Delivery—Texas

Requesting entity pays the total cost.

PPL Electric Utilities—Pennsylvania

Transmission: PPL does not have a program in place to convert existing overhead Transmission facilities into an underground system.
Distribution: At a customer's request, we will provide an estimate of the costs to relocate our facilities. This is defined in our tariff.

Public Service of New Hampshire—New Hampshire

The customer is responsible for all costs in excess of overhead construction costs

Puget Sound Energy—Washington

Occasionally underground portions of our system that have a high number of tree related outages and have exhausted all overhead improvements are placed underground.

Southern California Edison—California

Rule 20—Replacement of Overhead with Underground Electric Facilities
(Note: only section A of Rule 20 is provided below)
A. SCE will, at its expense, replace its existing overhead electric facilities with underground electric facilities along public streets and roads, and on public lands and private property across which rights-of-way satisfactory to SCE have been obtained by SCE, provided that:
1. The governing body of the city or county in which such electric facilities are and will be located has:
a. Determined, after consultation with SCE and after holding public hearings on the subject, that such undergrounding is in the general public interest for one or more of the following reasons: such undergrounding will avoid or eliminate an unusually heavy concentration of overhead electric facilities; the street or road or right-of-way is extensively used by the general public and carries a heavy volume of pedestrian or vehicular traffic; the street or road or right-of-way adjoins or passes through a civic area or public recreation area or an area of unusual scenic interest to the general public; or the street or road or right-of-way is considered an arterial street or major collector road, as defined in the Governor's Office of Planning and Research General Plan Guidelines.
b. Adopted an ordinance creating an underground district in the area in which both the existing and new facilities are and will be located requiring, among other things, that all existing overhead communication and electric distribution facilities in such district shall be removed, that each property served from such electric overhead facilities shall have installed in accordance with SCE's rules for underground service, all electrical facility changes on the premises necessary to receive service from the underground facilities of SCE as soon as it is available, and authorizing SCE to discontinue its overhead service.

We Energies—Michigan, Wisconsin

Distribution Planning, Protection, and Reliability Groups are responsible for assessing the performance of existing overhead and underground systems. Decisions to convert existing overhead facilities to underground construction are made on a case-by-case basis in concert with expected reliability targets and standard designs.

Western Massachusetts Electric—Massachusetts

For specific customer, i.e., non-municipal requests, the Customer would pay the full cost to underground and existing overhead system. For municipal requests, a municipal vote is required and the cost for undergrounding is recovered through a rate addition paid by residents of the municipality. We discourage this practice as it raises rates and may result in longer restoration times.

Xcel Energy—Colorado and Minnesota

All transmission, distribution, and secondary conversion are paid for by a third party. Some franchise agreements (CO) have a 1 percent of revenue fund for franchisee designated undergrounding projects. In MN, cities may request undergrounding projects that are paid for by customers with a limited bill reimbursement surcharge over five years. These are mainly for aesthetic and/or safety reasons. Distribution and secondary policy is stated in the state PUC tariff filings.

Appendix D: State Undergrounding Studies

2012, September 24 – *Weathering the Storm: Report of the Grid Resiliency Task Force*, Office of Governor Martin O'Malley of Maryland, Executive Order 01.01.2012.15

Executive Summary

On July 25, 2012, Governor Martin O'Malley signed Executive Order 01.01.2012.15 directing his Energy Advisor, in collaboration with identified agencies, to solicit input and recommendations from experts on how to improve the resiliency and reliability of the Maryland electric distribution system. The Executive Order specifically charged the Task Force with evaluating:

1. The effectiveness and feasibility of undergrounding supply and distribution lines;
2. Other options for infrastructure investments to improve resiliency of the grid; and
3. Options for financing and cost recovery for capital investment.

Foundational Principles of the Task Force

The Task Force established several foundational principles that guide its recommendations:

- The current level of reliability and resiliency during major storms is not acceptable.
- Increased reliability and resiliency during major storms is the goal of the Task Force and will inform the recommendations.
- Severe weather events resulting from climate change are likely to continue to occur. It is unacceptable for anyone involved in response efforts to continue to be surprised by the "worst storm" the system or the State has ever seen. Utilities, government, and citizens must be prepared for severe weather events.
- If done strategically and appropriately, increased expenditures by the utilities to improve resiliency and harden the gird—to literally ensure that the electric distribution system can weather the storm—will lead to fewer outages during storms and shorter outages when interruptions happen.

Recommendations of the Task Force

1. Improve RM43's reliability and reporting requirements
2. Accelerate RM43's march toward reliability
3. Allow a tracker cost recovery mechanism for accelerated and incremental investments
4. Implement a ratemaking structure that aligns customer and utility incentives by rewarding reliability that exceeds established reliability metrics and penalizes failure to reach those metrics
5. Perform joint exercises between the state and utilities
6. Facilitate information sharing between utilities, state agencies, and emergency management agencies
7. Increase citizen participation in list of special needs customers and share information with emergency management agencies

8. Evaluate state-wide vegetation management regulations and practices beyond RM43
9. Determine cost-effective level of investment in resiliency
10. Study staffing pressures due to graying of workforce
11. Task the energy future coalition with developing a pilot proposal

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2010, July 1—Public Service Commission of the District of Columbia
Study of the Feasibility and Reliability of Undergrounding Electric Distribution lines in the District of Columbia, by Shaw Consultants International, Inc.

Executive Summary:

This study did not draw a conclusion on undergrounding but provided several different approaches to consider if the Commission decides to pursue undergrounding. The study's objectives were to:

- Provide a comprehensive review and analysis of previous undergrounding studies including studies and analyses performed by Pepco
- Provide costs, feasibility, and reliability implications of select undergrounding alternatives to the existing overhead distribution system
- Examine the potential impacts of undergrounding projects on the environment, residents, infrastructure, and health and safety.

The study proposed three different approaches to undergrounding the electric facilities in the District of Columbia. They are:

Option	Total Cost	Reliability Improvement
Undergrounding all existing overhead assets	$ 5.8 Billion	1030 fewer outage events annually
Undergrounding all mainline primary and laterals	$ 2.3 Billion	924 fewer outage events annually
Undergrounding all mainline primary	$ 1.1 Billion	462 fewer outage events annually

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2009, April 21—Houston, Texas *Electric Service Reliability in the Houston Region,* Mayor's Task Force Report

Executive Summary:

- After landfall of Hurricane Ike in September 2008, the electrical grid in the greater Houston area failed broadly, causing personal hardship and economic loss to residents and businesses in our area. Approximately 3.5 million people were without electrical power in the immediate aftermath of the storm, and it was fully two weeks before electrical power was restored to many homes and businesses in the region. Coming only three years after a similar, although less pervasive, power outage in the aftermath of Hurricane Rita, the citizens of Houston, along with local media and civic leaders, began a dialog about our regional electrical grid: Is it overly fragile? Should we take measures to harden its infrastructure against storm-related failure? Are there new technologies that might enhance the resiliency of our electrical power delivery system? Are there strategies we should encourage for citizens who want to prepare their own environment for the next outage?

- In October of 2008, Mayor Bill White convened a Task Force to explore the options for hardening our electrical grid against catastrophic failure during hurricane events and, by extension, against lesser weather events or terrorist actions. The Task Force was comprised of members from government, utility, business, regulatory, and environmental technology backgrounds. CenterPoint Energy, the regional transmission and distribution utility, was an active participant. The Task Force convened monthly and assigned research tasks between meetings, attempting to cast a wide net to capture expert opinion on a variety of topics, including the cause of Houston's recent grid failures, and strategies to increase resilience and recovery in anticipation of future storm events.
- The conclusions of the Task Force related to undergrounding are summarized here:
  - The cause of grid failure during Hurricane Ike was predominantly falling trees and tree limbs across power distribution and service lines, rather than the wind or water directly. No high-voltage transmission lines failed, no substations failed, and fewer than 1 percent of the distribution system's one million wooden poles were knocked out of commission, suggesting that improved vegetation management will have a more significant effect on reliability than would replacement of wooden poles with steel or concrete.
  - The cost of undergrounding the existing distribution infrastructure is prohibitive. It would cost an estimated $35 billion to bury the cables of the entire regional distribution system, which is cost prohibitive. Undergrounding has other costs in traffic congestion and business losses as rights-of-way are excavated. Furthermore, while undergrounding reduces risk of grid failure due to wind damage, it increases vulnerability to flood damage such as that seen in Tropical Storm Allison in 2001.
  - Some selective undergrounding makes sense. When developing new land parcels, undergrounding is economically rational: earthmoving is underway, and disruption to existing infrastructure is minimal. Ninety percent of all new residential distribution facilities since 1990 have been placed underground. Also, critical facilities that serve a critical role in disaster recovery might be given priority for selective undergrounding, when excavation for some other capital purpose (sewer, water main, or roadbed replacement) is otherwise required.

2008, June 30—Oklahoma
Oklahoma Corporation Commission's Inquiry into Undergrounding Electric Facilities in the State of Oklahoma, Prepared and Submitted by Oklahoma Corporation Commission Public Utility Division Staff

Excerpt of the Executive Summary:

- The purpose of this report is to gather, develop, and provide the Oklahoma Corporation Commission with relevant information to assist the Commissioners in making an informed decision as to what actions, if any, should be taken regarding future plans and development to protect electric plant in the State of Oklahoma from weather events to assure reliable service for state electric customers.
- The need for this study surfaced when on December 8 and continuing through December 10, 2007, the State of Oklahoma experienced one of the most disruptive ice storms in the state's history. The Commission's Customer Service Division reported the storm resulted in more than 600,000 homes and businesses across the state being without electric service. Many customers were without electric service for several days while others were without service for a week or more. This storm followed by less than 12 months another "storm of the century" in which rural portions of Oklahoma suffered

even greater physical damage to the electricity infrastructure, although loss of life was less and the homes and businesses affected were fewer.

- Following this storm and cleanup efforts, the Oklahoma Corporation Commission conducted a meeting on January 7, 2008, to discuss the impact of severe storms on state utilities. More specifically, the meeting was conducted to discuss advantages, disadvantages, and feasibility of moving more aggressively to bury power lines, as well as the impact burying electric lines may have on electric customers across the State of Oklahoma.
- Staff's review of this issue also included meeting on January 10 and January 15, 2008 with representatives from Oklahoma's two largest investor-owned electric utilities, Public Service Company of Oklahoma (PSO) and Oklahoma Gas and Electric Company (OG&E), to gain additional insight about the potential of undergrounding electric transmission and distribution facilities. On January 16, 2008, Staff issued an extensive data request to all retail electric utilities and cooperatives operating in the State of Oklahoma, in order to gain additional information about utility operations and activities affecting utility response to storm outages. The Staff also met with members of the Oklahoma Climatological Survey on February 1, 2008, to discuss the impact of severe weather conditions and the frequency of such conditions, which will likely continue to have a negative impact on Oklahoma's electrical plant and Oklahoma customers.
- Information gathered from the various in-depth commission studies clearly indicated that requiring electric utilities to underground all of their facilities is generally not a feasible solution. The cost to underground all transmission and distribution facilities in any state would likely run into the billions of dollars, and the potential impact on customers would be significant, to say the least. Approaching thousands of dollars per customer.
- No public utility commission has found a funding mechanism that will permit undergrounding of electric facilities to be completed on any sort of universal or fast track basis. However, commissions have attacked this problem by addressing very specific parts of the electric grid, e.g., poorly performing circuits, lines along road rights of way undergoing construction, all secondary line extensions, etc.
- The potential financial impact of undergrounding all electric facilities is generally accepted to be in the billions of dollars, which would cause an enormous and impractical burden to customers. For example, there are approximately 8,551 miles of main (or feeder) distribution lines and approximately 34,600 miles of lateral distribution lines in Oklahoma. Using information supplied in response to the Staff's January 16, 2008 data request, the cost to underground existing overhead main and lateral distribution lines is estimated to be between $435,000 and $2.5 million per mile, depending on certain conditions, resulting in an estimated statewide cost of $30.5 billion to underground only distribution lines.
- The $30.5 billion does not include burial of transmission lines, which require special treatment due to heat-dissipation issues not present with distribution lines. Oklahoma has approximately 7,500 miles of transmission facilities. Oklahoma electric utilities had a difficult task estimating the cost to underground these facilities in their response to Staff's data requests.
- To put these numbers into perspective, consider that the State Equalization Board's determination of funds available for legislative appropriation in Fiscal Year 2009 is approximately $7 billion, making the estimated cost of burying all electric lines in Oklahoma more than six times the annual State budget. The cost is also roughly four times the total value of all centrally assessed public utility assets in the State, as determined by the Tax Commission. Monthly electric bills would have to increase $80 to $260 for 30 years to pay for the cost of burial; contingent upon how much of the electric network is placed underground.

2008, May 21─Florida
Undergrounding Assessment Phase 3 Report: Ex Ante Cost and Benefit Modeling, by Richard Brown, Quanta Technology

Excerpt of the Executive Summary:

- This report is the Phase 3 deliverable of a project awarded in response to RFP #U-1 issued by the Florida Electric Utilities. RFP #U-1 was a result of Florida Public Service Commission Order No. PSC-06-0351-PAA-EI, which directs each investor-owned electric utility in Florida to establish a plan that increases collaborative research to further the development of storm-resilient electric utility infrastructure and technologies that reduce storm restoration costs and interruptions to customers. Municipal electric and cooperative electric utilities are participating voluntarily.
- The scope of the overall project (all three phases) is to investigate the implications of converting overhead electric distribution systems in Florida to underground (referred to as undergrounding).
- Phase 3 develops and tests a methodology for analyzing the costs and benefits of specific undergrounding proposals in Florida. The methodology is separated into two basic components: normal weather assessment and hurricane assessment. The normal weather model includes the basic cost of utility capital and operational cost information. It also includes high-level reliability information that allows for the calculation of customer interruption information and related costs.
- It is well-known that the conversion of overhead electric distribution systems to underground is costly, and these costs almost always exceed quantifiable benefits. This conclusion is reached consistently in many reports that range from state-wide studies to very small projects. However, there is no consistent approach has been used to compute the costs and benefits of proposed undergrounding projects, making studies difficult to interpret and use for making decisions.
- As more areas in Florida begin to explore the possibility of underground conversion, it becomes increasingly desirable to have a consistent methodology to assess the associated costs and benefits. Results from a trusted approach can provide insight, lead to better projects, aid in customers communicating with utilities, and potentially help guide certain regulatory approaches.
- This report has presented a methodology capable of computing the costs and benefits of potential undergrounding projects. The methodology can also be used to compute the costs and benefits of other activities that have an impact on hurricane performance such as the hardening of overhead systems. The methodology used a detailed simulation with the following components: hurricane module, equipment damage module, restoration module, and cost-benefit module. This methodology has been implemented in a spreadsheet application so that it can be easily used by interested parties.
- The conversion of overhead electric infrastructure to underground is of interest around the country and around the world. Often times underground conversion proposals are either pursued or rejected without a systematic analysis of costs and benefits. The methodology presented in this report is an attempt to add consistency, rigor, and thoroughness to these types of analyses. At present, the methodology is specific to the state of Florida, but the general approach is valid wherever extreme weather events have the potential to wreak havoc on electricity infrastructure.

2007, August 6─Florida
Undergrounding Assessment Phase 1 Report: Undergrounding case Studies, by Richard Brown, InfraSource Technology

Executive Summary:

- This report presents the results of Phase 2 of a three-phase project to investigate the implications of converting overhead electric distribution systems in Florida to underground (referred to as undergrounding). The purpose of Phase 2 is to examine the cost and benefits of actual undergrounding projects that have been completed. The focus is to identify the drivers of each project, discuss the challenges of each project, and to collect data that can serve as a real-world basis for *ex ante* modeling in Phase 3.
- A review of the case studies reaches the same conclusion reached in Phase 1 literature review: the initial cost to convert overhead distribution to underground is high, and there is insufficient data to show that this high cost is 100 percent justifiable by quantifiable benefits such as O&M cost saving and reduced hurricane damage. Increased data collection can potentially increase the amount of quantifiable benefits, but it is unlikely that these benefits will 100 percent justify high initial cost, except potentially in a situation where an undergrounded system is struck by multiple severe hurricanes. For all of these case studies, by far the strongest reason for undergrounding is to improve the aesthetics of the area. Additional observations relating to these case studies include:
    - All case studies occurred in coastal areas.
    - Two of the four projects were done in conjunction with roadway widening projects.
    - More circuit miles of underground are sometimes built than the original overhead amount. This is typically to create an underground loop that increases operational flexibility and the ability to respond to faults.
    - Cost per circuit mile figures correspond to those identified in Phase 1 literature search.
    - Cost per customers varies widely based on both the cost per circuit mile and the amount of high density housing such as high rise condominiums.
- Not much data is available on the impact of the case studies on non-storm reliability and hurricane performance. The little data that is available indicates that non-storm reliability is not significantly different after undergrounding and that hurricane reliability of underground systems is not perfect due to storm surge damage.
- For these case studies, there is an extensive amount of project description and project cost data, but limited avoided cost and benefit data. These case studies can certainly be used as an input for an *ex ante* model, but there is not sufficient data to compare the output of the *ex-ante* model to historical realized benefits. There is not even enough data to determine upper and lower bounds of potential results. At this point, any *ex ante* model that is developed, such as one to be developed in Phase 3, must be justified by its model assumptions rather than by its ability to replicate realized benefits from any of these case studies.

2007, February 28─Florida
Undergrounding Assessment Phase 1 Final Report: Literature Review and Analysis of Electric Distribution Overhead to Underground Conversion, by Richard Brown, InfraSource Technology

Executive Summary:

- The conversion of overhead electric power distribution facilities to underground has been a topic of discussion in Florida for more than 20 years. The topic has been studied, discussed, and debated many times at the state, municipal, and local levels. Overhead construction is the standard in Florida, but all investor-owned utilities are required to have a process where customers can opt to underground existing overhead service by paying the incremental cost. For municipals and cooperatives, the decision to underground is left to the local citizen boards.
- This report presents the results of a review of relevant previous undergrounding studies done in Florida as well as literature on the subject from throughout the U.S. and around the world. This review finds that the conversion of overhead electrical distribution systems to underground is costly, and these cost are far in excess of the quantifiable benefits presented in existing studies, except in the rare case where the facilities provide particularly high reliability gains or otherwise have a higher than average impact on the community goals.
- This conclusion is reached consistently in many reports, which almost universally compare the initial cost of undergrounding to the expected quantifiable benefits. No prior cost benefit study recommends broad-based undergrounding, but several recommend targeted undergrounding to achieve specific community goals.

2005, January 7─Virginia
Placement of Utility Distribution Lines Underground, Report to the State Corporate Commission

Executive Summary:

- The primary advantages of underground circuits are improved aesthetic and the overall improved reliability. In addition, underground rights-of-way require little tree trimming and underground facilities are much less susceptible to motor vehicle accidents. However, the relocation of currently existing overhead lines would result in the tremendous cost and significant disruption. In addition, a major relocation initiative could take decades to complete and encounter complications regarding underground damage prevention and attainment of new easements.
- The cost associated with the placement of the currently existing overhead electric utility distribution facilities underground was estimated by utilities to be over $80 billion. The resultant annualized revenue requirement on a per customer basis would be approximately $3,000.
- The potential benefits, both to the utilities and to the economy, resulting from the elimination of tree trimming maintenance, vehicle accidents, post-storm restoration, and lost sales during outages do not appear to be sufficient to offset the initial construction costs associated with a comprehensive program to relocate the currently existing overhead utility distribution lines to underground. The placement of all new distribution line underground, though not as costly, is also probably not cost effective.
- Regardless of the funding options available for a comprehensive statewide initiative, the cost would be paid ultimately by consumers, either directly or indirectly, in the form of prices, taxes, or utility rates. Anecdotal evidence suggests that consumers might not be willing to pay the cost necessary to fund a comprehensive statewide initiative.

- Based on our research and analysis and input from interested parties, the wholesale relocation of the currently existing overhead utility distribution lines and placement of all new utility distribution lines underground is probably reasonable. The economic effects of such an effort on state and local governments or utilities, and ultimately customers, would be significant.

2003, December 30─Maryland
Task Force to Study Moving Overhead Utilities Lines Underground

Finding:

- No new laws are necessary to facilitate undergrounding projects
- Improved aesthetics is the primary reason to underground overhead utilities
- Undergrounding can enhance public safety
- Undergrounding remains very expensive─cost is the primary obstacle
- When undergrounding, economies of scale can be realized if all overhead utilities (electric, cable TV, phone) are relocated at the same time
- Further saving can be realized if undergrounding is done in connection with planned infrastructure improvements to roadways or other underground utilities
- Undergrounding is desirable in certain instances
- While the frequency of outages may be significantly improved in the short-term, the long-term reliability of undergrounding is more questionable
- Underground cables are more susceptible to damage during excavation activities
- While underground outages may occur less frequently, they generally take longer to repair

2003, November 21─North Carolina
The Feasibility of Placing Electric Distribution Facilities Underground, Report of The Public Staff to The North Carolina Natural Disaster Preparedness Task Force

Executive Summary:

- In early December 2002, a major ice storm blanketed much of North Carolina with up to one inch of ice, causing an unprecedented power outage to approximately two million electric utility customers. In the immediate aftermath of the storm, the public expressed considerable interest in burying all overhead power lines in the state. The Public Staff responded by investigating the desirability and feasibility of converting the existing overhead lines of the state's three investor-owned electric utilities─Duke Power ("Duke"), Progress Energy Carolinas ("Progress Energy"), and Dominion North Carolina Power ("Dominion") (collectively, "the Utilities")─to underground. Since the majority of the damage sustained in severe weather events usually involves distribution rather than transmission lines, the Public Staff's investigation focused on undergrounding this portion of the electrical power delivery system. The primary purpose of this report is to present the results of that investigation.
- The investigation consisted of (1) comparing the operational advantages and disadvantages of overhead and underground power distribution systems; (2) estimating and comparing the capital

costs of converting overhead lines to underground, along with the differences in operation and maintenance (O&M) costs for the two types of systems; (3) estimating the time and human resources required to bury underground lines; (4) identifying potential additional costs to customers, municipalities, and other utilities that may result from conversion; and (5) exploring options for financing conversion projects. The Utilities provided valuable assistance throughout the investigation, and the Public Staff gratefully acknowledges their contribution to this report.

- The Public Staff has determined that replacing the existing overhead distribution lines of the Utilities with underground lines would be prohibitively expensive. Such an undertaking would cost approximately $41 billion, nearly six times the net book value of the Utilities' current distribution assets, and would require approximately 25 years completing. The ultimate impact of the capital costs alone on an average residential customer's monthly electric bill would be an increase of more than 125 percent. Rates would also be impacted by the higher O&M costs associated with direct-buried underground systems, particularly in urban areas, where underground conductors are four times more costly to maintain than overhead facilities. In addition to the impact on the cost of providing utility service, conversion to underground would impose costs on individual customers, municipalities, and other utilities. While these costs have not been quantified, they could be significant.
- The Public Staff has also determined that underground facilities are not without their disadvantages. Although underground systems are more reliable than overhead systems under normal weather conditions, they are not impervious to damage, and the repair time for underground systems is almost 60 percent longer than for overhead systems when damage does occur. Consequently, the Public Staff does not recommend that the Utilities undertake the wholesale conversion of their overhead distribution systems to underground.
- The Public Staff does recommend, however, that each of the Utilities (1) identify the overhead facilities in each region it serves that repeatedly experience reliability problems based on measures such as the number of outages or number of customer-hours out of service, (2) determine whether conversion to underground is a cost-effective option for improving the reliability of those facilities, and, if so, (3) develop a plan for converting those facilities to underground in an orderly and efficient manner, taking into account the outage histories and the impact on service reliability. Such a plan might include a policy similar to that of Dominion Virginia Power of annually identifying the "worst 10 circuits" and "worst 10 devices" in each of its regions and taking appropriate steps to improve or replace each of these circuits and devices.
- In the meantime, the Public Staff recommends that the Utilities continue their current practices of (1) placing new facilities underground when the additional revenues cover the costs or the cost differential is recovered through a contribution in aid of construction, (2) replacing existing overhead facilities with underground facilities when the requesting party pays the conversion costs, and (3) replacing overhead facilities with underground facilities in urban areas where factors such as load density and physical congestion make service impractical from overhead feeders.

1999, December 30—Maryland
Undergrounding Electric Utility Lines in Maryland, by Exeter Associates, Inc.

Findings:

- The utilities' transmission system, sub-transmission systems, and substations were largely unaffected by ice storms and Hurricane Floyd and significant efforts for these components were not required.

- Almost all of the restoration efforts related to the ice storm and Hurricane Floyd were directed toward distribution mains, distribution laterals from mains, secondary conductors, and service conductors directly connecting end users.
- Relative to overhead lines, underground lines offer advantages in terms of aesthetics; reduced susceptibility to damage from wind, ice, and vehicles; reduced operation and maintenance cost; and minimization of inadvertent contact with lines by people and animals.
- Relative to overhead lines, underground lines present disadvantages in terms of installation costs; power-carrying capacity; the ease (and cost) of locating and correcting problems on the lines; the ease of performing system upgrades; and certain ancillary concerns such as traffic disruptions during installation, arranging for placement of above-ground transformers on private property, and possible impacts on above-ground utility systems, e.g., telephone and cable television.
- Assuming an average cost per mile of $450,000 for undergrounding the existing OH distribution system of PEPCO and BGE, the cost of underground would result in substantial increase in electric utility rates if funding for undergrounding were to be collected fully from distribution service ratepayers. Increases in residential rates are estimated to be approximately 36 percent for BGE customers (or an increase of approximately $340 per year) and 46 percent for PEPCO customers (or an increase of approximately $415 per year).
- Costs for undergrounding existing overhead lines vary significantly depending on the specific characteristics of the area, such as topography, geology, and land use.
- Completion of conversion to UG lines for substantial portions of the OH distribution system will likely require 15 to 20 years for planning, design, and construction.

1999, December—Hawaii
Undergrounding Public Utility Lines, by Pamela Martin, for Legislative Reference Bureau

Executive Summary:

- This report examines the policies and issues of undergrounding public utility lines. The policies and issues discussed in Chapter 2 have been categorized into seven topics: (1) type of line, (2) location, (3) benefits of undergrounding, (4) costs, (5) public sentiment, (6) technological issues, and (7) legal matters. The discussions within each topic address related issues and refer to assorted documents that may be of interest in those particular areas. Chapter 3 of this report reviews the treatment of undergrounding in other jurisdictions. Finally, Chapter 4 discusses the theory and process of public utility actions and suggests alternatives to address some of the problematic issues identified in Chapter 2. Legislation is included in the appendices for all suggestions.
- While all of the issues discussed are relevant, the issues of benefits and cost have the most significance with regard to requirements of the current law in evaluating whether or not electrical lines should be underground in section 269-27.6, Hawaii Revised Statutes. The structure of the law requires a balancing of benefits and costs but without a standard to measure benefits, it is almost impossible to accurately compare these issues. The study suggests that the Consumer Advocate should be provided with the tools to measure benefits that include the valuation of certain intangibles. This measurement of externalities is necessary to complete the current analysis required under the law. Costs are considered from the perspectives of consumers, the utilities, and government. The study also looks at cooperative funding from all entities.

- Regarding plans for the conversion of overhead lines to underground, this report focuses on the solutions presented by the California Public Utility Commission. The California PUC has actively pursued the conversion of overhead utility lines to underground for thirty years by establishing guidelines for counties and requiring utilities to participate by allocating as much as two percent of a utility's gross revenues to undergrounding. Counties and consumers are expected to share costs according to locations and criteria set by both the California PUC and counties.
- The final analysis of the issues highlights the need to develop the measurement of intangibles; create independent review throughout the process in order to reduce built-in bias; establish clearer communication lines between consumers and PUC operations; promote quality consumer participation in the process; encourage settlement through alternative dispute resolution; and provide for safety through the establishment of a one-call system.