LIFE-CYCLE 2012

Connecticut Siting Council Investigation into the Life-cycle Costs of Electric Transmission Lines

Final Report

Prepared for the Connecticut Siting Council
Prepared by KEMA, Inc.
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Executive Summary

This report is prepared and updated every five years by the Connecticut Siting Council and is intended to provide useful information regarding the cost of transmission lines in the State of Connecticut to the general public. In addition to providing quantitative data, it provides general information about transmission line cost elements that are affected by regulatory requirements, environmental regulations, line type, and maintenance requirements. There also is a discussion of existing and new technologies and how they could affect future line costs. A description of the Net Present Value (NPV) method of evaluating transmission life-cycle costs is presented in Section 1. First costs for transmission lines applicable to Connecticut are presented in Section 2. Of the four overhead and four underground line types that were considered in this report, the total first cost of each line type are listed from least to most costly, as follows in Table ES-1:

Table ES-1: Ranking of Transmission Line First Costs

Line Type	Total First Costs
Overhead 115 kV Wood H-Frame	$3,315,400
Overhead 115 kV Steel Delta	$4,871,000
Overhead 345 kV H-Frame	$5,421,200
Overhead 345 kV Steel Delta	$7,714,800
Underground 115 kV HPFF	$14,970,677
Underground 345 kV HPFF	$16,634,086
Underground 115 kV XLPE	$18,780,600
Underground 345 kV XLPE	$21,970,700

Note: costs are in $ per circuit-mile.

As illustrated by this ranking, first costs for underground transmission lines can range from roughly three to six times more than those for overhead transmission lines. Key factors affecting first costs are presented in Section 3. Greatly varying costs related to right-of-way (ROW) differences, permitting and legal requirements, cost of materials and labor, escalation, and environmental costs are discussed in general terms.

Cost differences between overhead and underground transmission technologies are discussed in Section 4, along with the concept of a "hybrid" line. Emerging transmission technologies, Flexible AC Transmission Systems (FACTS), High-Voltage Direct-Current (HVDC) Transmission Lines, High-Temperature, Low-Sag (HTLS) Conductors, Superconductors, and the applicability of each of these technologies in the State of Connecticut are also presented in this section.

Transmission loss costs are presented in Section 5. The loss calculation method is presented along with a general discussion of key factors contributing to the cost of losses. The formula for calculating electrical energy losses is provided in the Appendix.

Annual operations and maintenance (O&M) costs of transmission lines are presented in Section 6. Since underground transmission O&M costs in the State of Connecticut were affected by significant underground cable failures in 2007 and 2009, an average of 2009 and 2010 O&M expenditures was used as the basis for the underground life-cycle cost calculation. To capture the most recent data, 2010 O&M expenditures were used as the basis for the overhead life-cycle cost calculation.

Cost effects of electric and magnetic field (EMF) mitigation are presented in Section 7. For more information, please review the Council's "Electric and Magnetic Fields Best Management Practices for the Construction of Electric Transmission Lines in Connecticut", located in the Appendix. This document presents information available on acceptable transmission line EMF mitigation practices for the State of Connecticut.

Environmental considerations and costs are presented in Section 8. Some examples of remediation plans that resulted in high environmental costs are provided to illustrate the specific nature of these expenditures and how quickly they can become a major portion of the project cost.

Life-cycle cost calculations for the lines referenced in this report are presented in Section 9. The economic assumptions used in the life-cycle cost calculations include:

Capital Recovery Factor:	14.1 percent
O&M Cost Escalation Factor:	4.0 percent
Load Growth Factor:	2.03 percent
Energy Cost Escalation Factor:	1.2 percent
Discount Rate (inflation):	8.0 percent

The NPV of transmission line costs over a 40-year life were calculated for each of the lines referenced in this report.

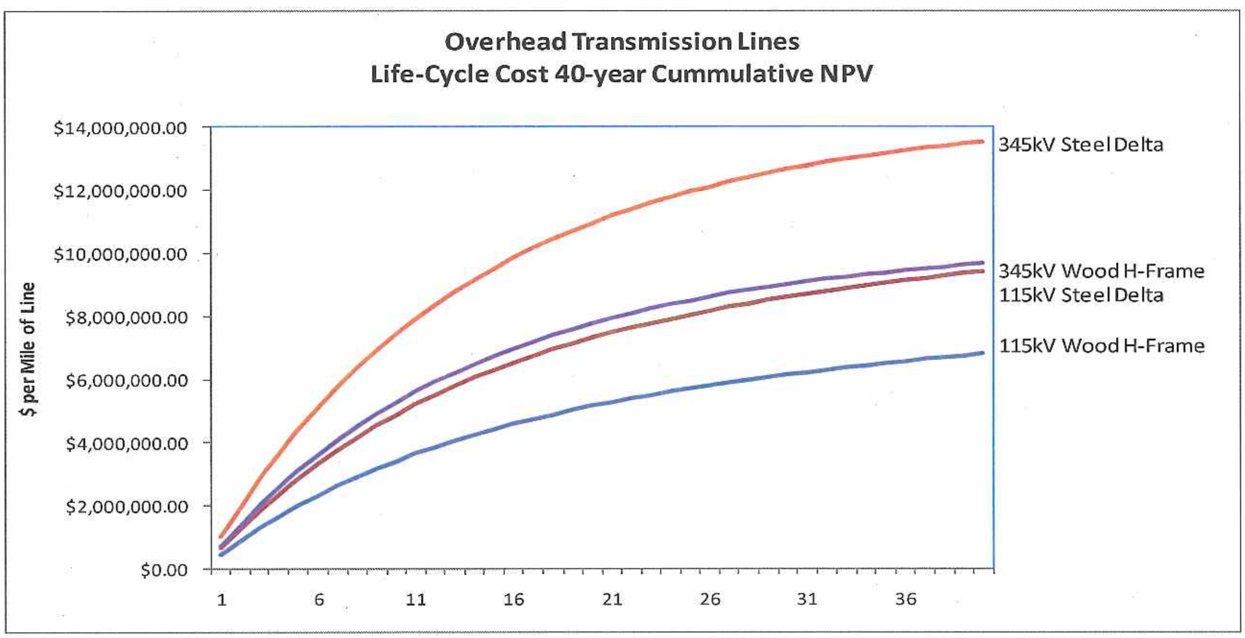
The overhead transmission line life-cycle costs are shown in Table ES-2:

Table ES-2: NPV of Overhead Life-cycle Cost Components

LCC Component	115 kV Wood H-Frame	115 kV Steel Delta	345 kV H-Frame	345 kV Steel Delta
Poles & Foundations	$1,034,631	$2,450,297	$2,280,275	$4,739,447
Conductor & Hardware	$1,307,434	$1,410,458	$2,476,827	$3,043,953
Site Work	$1,616,554	$2,483,186	$2,435,045	$2,850,427
Construction	$227,826	$229,568	$228,919	$247,750
Engineering	$334,465	$818,996	$455,752	$648,572
Sales Tax	$118,215	$188,155	$229,357	$369,433
Admin/PM	$935,291	$609,297	$1,008,872	$1,071,855
Losses	$263,512	$263,512	$107,002	$107,002
O&M Costs	$96,631	$96,631	$96,631	$96,631
Total LCC	$5,934,559	$8,550,100	$9,308,680	$13,175,070

The yearly growth in cumulative NPV of life-cycle costs for each of the overhead line types is shown in Figure ES-1.

Figure ES-1: Overhead Transmission Lines Life-cycle Cost 40-Year Cumulative NPV



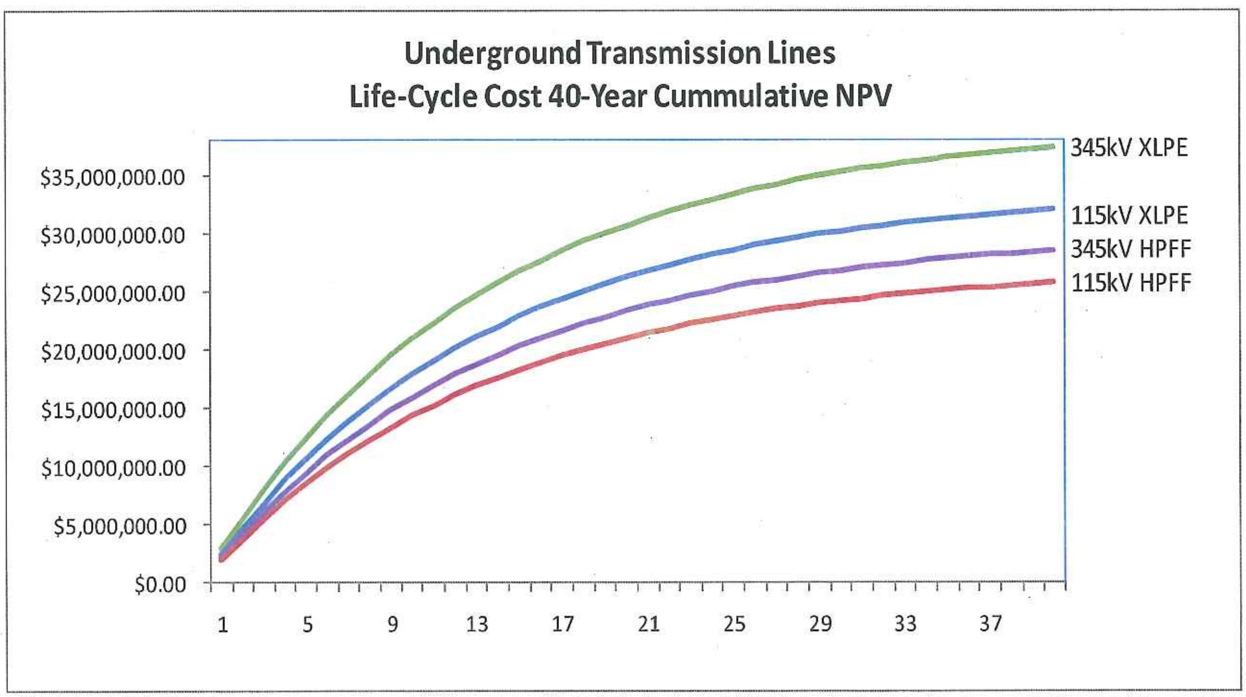
The total NPV of the underground transmission line life-cycle costs for each underground line type considered is shown in Table ES-3.

Table ES-3: NPV of Underground Transmission Life-cycle Cost Components

LCC Component	115 kV XLPE	115 kV HPFF	345 kV XLPE	345 kV HPFF
Ducts & Vaults	$10,104,687	$8,935,795	$11,821,084	$9,928,661
Cable & Hardware	$11,052,001	$7,677,232	$12,929,310	$8,530,258
Site Work	$5,052,343	$4,530,826	$5,910,542	$5,034,250
Construction	$631,543	$503,426	$738,818	$559,362
Engineering	$789,429	$629,281	$1,108,227	$839,042
Sales Tax	$1,002,259	$787,357	$1,172,504	$874,841
Admin/PM	$2,944,885	$2,107,338	$3,260,403	$2,201,647
Losses	$81,062	$95,883	$81,062	$95,883
O&M Costs	$177,000	$177,000	$177,000	$177,000
Total LCC	$31,835,212	$25,444,137	$37,198,951	$28,240,945

The yearly growth in cumulative NPV of life-cycle costs for each of the underground line types are shown in Figure ES-2.

Figure ES-2: Underground Transmission Lines Life-cycle Cost 40-Year Cumulative NPV



From this life-cycle cost comparison, one can make some general observations about the cost of transmission lines in the State of Connecticut:

1. The total life-cycle cost of steel delta 115 kV overhead lines is roughly 44 percent higher than wood H-frame lines. One of the major reasons is the cost of materials. Similarly, the total life-cycle cost of steel delta 345 kV overhead lines is roughly 41 percent higher than H-frame lines.
2. The total life-cycle cost of overhead 345 kV lines is approximately 54 to 57 percent higher than overhead 115 kV lines, while providing 3 times the capacity for an equivalent conductor size.
3. The total life-cycle cost of underground XLPE cables is 25 to 32 percent higher than for HPFF cable systems. Since HPFF (fluid-filled cable) is the environmentally undesirable choice near waterways, this cable is also not being used as much as in the past.
4. The total life-cycle cost of underground 345 kV cables is roughly 11 to 17 percent higher than underground 115 kV cables, while providing 3 times the capacity for an equivalent conductor size.
5. The total life-cycle cost of underground lines is roughly two to five times higher (mirroring first costs) than the cost of overhead lines at the same voltage level.

The Appendices contain useful reference data and the life-cycle cost calculations for each specific line type considered in this report. The cost data presented in this report are specific to Connecticut utilities and should not be used for estimating costs in other states.

Background and Introduction

Pursuant to Connecticut General Statutes § 16-50r (b), the Connecticut Siting Council is required to prepare and publish information on transmission line life-cycle costs (LCCs) every five years. The previous report, issued in 2007, investigated the costs of 115 kV and 345 kV transmission lines. This report provides current updated information on those costs.

To assist the Council in this matter, the Council retained the services of the technical consulting firm KEMA, Inc. (KEMA). The Council held a public hearing on life-cycle costs and also provided an opportunity for public comment on November 15, 2011. A continued hearing was also held on January 17, 2012. Other participants in this proceeding are The Connecticut Light and Power Company (CL&P) and The United Illuminating Company (UI). CL&P and UI are the primary owners/operators of electric transmission in the State of Connecticut. CL&P's territory contains approximately 93 percent of the transmission circuit mileage in the State, and UI's territory contains approximately 7 percent of the circuit mileage. With the assistance of KEMA, the Council prepared this final report.

The life-cycle costs of electric transmission lines include:

- Costs that are incurred to permit and build a line;
- Costs of operating and maintaining the line over its useful life; and
- Costs of energy losses resulting from the line's use. (Typically, all of the electrical energy losses are expressed in the equivalent dollar value for a single year, such as the year the line is first energized.)

In preparing this report, two key objectives were: to provide information that is relevant to Connecticut's future transmission decisions; and to provide data useful in comparing one transmission line to another equivalent line. Achieving these objectives was a challenging assignment. The transmission cost data submitted by the utilities in Connecticut and used in this report are based on the most current costs available for transmission lines in the State of Connecticut.

The life-cycle costs can be qualitatively compared with those identified from other eastern states that are similar in population, demographics, and terrain.

While recently-built lines are clearly the best sources of cost data, future transmission lines may have attributes that result in either higher or lower costs. Also, as this report discusses, two different transmission lines of the same voltage may have characteristics that make them quite difficult to compare as exact substitutes for one another. In response to these challenges, this report provides the best available cost information on recently-built transmission facilities and a discussion of how these costs have varied and might vary for future lines with different attributes.

1. Life-cycle Costs

Life-cycle costs are the total costs of ownership of an asset or facility from its inception to the end of its useful life. These costs include the design, engineering, construction, operation, maintenance, and repair of the asset. Life-cycle costs provide the information to compare project alternatives from the perspective of the least cost of ownership over the life of the project or asset [1].

Life-cycle cost calculations use the "time value of money" concept to evaluate alternatives on a common basis. NPV computations bring all anticipated expenses of a project or asset, over its entire useful life, to a present day value that is then used for comparison with other alternatives. NPV analysis is an accepted standard method for financial evaluation of alternatives in the capital budgeting process, and is commonly used by utility companies as a life-cycle cost methodology.

Transmission line life-cycle costs are a function of many factors, and can vary greatly from one project to another. Life-cycle costs are influenced by the line design required to meet the specific need, the geographic area through which the line is to be built, the regulatory and permitting requirements of the jurisdiction(s) involved and many other factors. Because each transmission line project is unique, the life-cycle costs for each project are specific to that application, and caution should be exercised in any attempt to compare life-cycle costs across different projects in different time periods. This report will discuss in detail the major elements of costs included in life-cycle costs, the factors influencing those costs, and the overall impact of the cost factors on a life-cycle analysis.

In the case of life-cycle cost analyses for transmission lines in Connecticut, the transmission operating utilities have a common view of what cost elements should be included and how they should be considered. There is general agreement that the life-cycle cost comparisons should be used to compare two assets that have a roughly equivalent useful life [2]. Whether a transmission line life is estimated at 35 years or 40 years is a subjective judgment based on the best information available. NPV analysis of transmission line costs shows that operations and maintenance costs incurred beyond year 25 have very little bearing on the NPV of a project and therefore, become insignificant in terms of materially changing the overall life-cycle cost evaluation. If there are no anticipated major investments for a rebuild or upgrade, for example, beyond year 25, whether the estimated life of a transmission line alternative is 35 years or 40 years is less significant. The critical factor is that alternatives be compared over an equivalent lifetime.

The transmission operating utilities in Connecticut have identified the following items as the major components of the life-cycle cost of an electric transmission line.

First costs typically include the following costs:

- Structures (poles/foundations or ducts/vaults);
- Conductors or cables with associated hardware;
- Site work;
- Construction work;
- Engineering;
- Sales Tax; and
- Administration and project management.

Operations and Maintenance (O&M) costs typically include labor and expenses for control and dispatching, switching, and other element of routine operation of a transmission line. Maintenance includes the costs of scheduled inspection and servicing of equipment and components as well as right-of-way (ROW) vegetation management, painting, general repairs, emergency repairs and all other activities required to keep a line in proper operating condition.

Electrical energy losses include the cost of the resistive losses of electrical energy that occur on a transmission line as reflected by the cost of producing that electricity.

Each of these components of transmission line life-cycle costs are examined in detail in this report. Both the key elements of costs and the factors that affect those costs are discussed. Section 9 gives examples of transmission line life-cycle costs based on typical cost data from utilities that own and operate transmission lines in the State of Connecticut. Appendix B presents the 40-year NPV calculations for each type of transmission line discussed in this report.

As mentioned earlier in this section, transmission line projects are specific to a particular need and application. Therefore, it is difficult to develop "typical" life-cycle costs that are meaningful beyond the specific project for which they are calculated. This report will, however, use recent project cost information to represent how different cost components can influence the life-cycle cost of a project. To be relevant to the State of Connecticut, this report examines the life-cycle costs of four basic types of alternating current (AC) transmission lines. The four types of lines are among those currently in use in Connecticut and the types that are most likely to be used in the near future. These include the following:

- 115 kV overhead transmission lines;
- 115 kV underground transmission lines;
- 345 kV overhead transmission lines; and
- 345 kV underground transmission lines.

Within each of these four basic types of lines there are variations of design and materials that will also be considered in the sample cost calculations.

Single versus Double-circuit Lines

The four basic types of "typical" transmission lines addressed in this report, whose life-cycle cost elements are shown in Figure 1-1 through Figure 1-4, focus on single-circuit construction types. Double-circuit lines are not "typical" in the State of Connecticut for reasons of reliability and are not presented in this report[3].

Life-Cycle Costs of Typical Lines

The life-cycle cost calculations use an energy cost of 4.8 cents per kilowatt hour for the purpose of calculating energy losses. This figure is consistent with average 2011 ISO New England electrical energy costs[4]. Figure 1-1 through Figure 1-4 offer a basis for understanding the contribution of the basic life-cycle cost elements that are detailed in this report.

Figure 1-1: Life-Cycle Cost for a Typical 115 kV Overhead Line

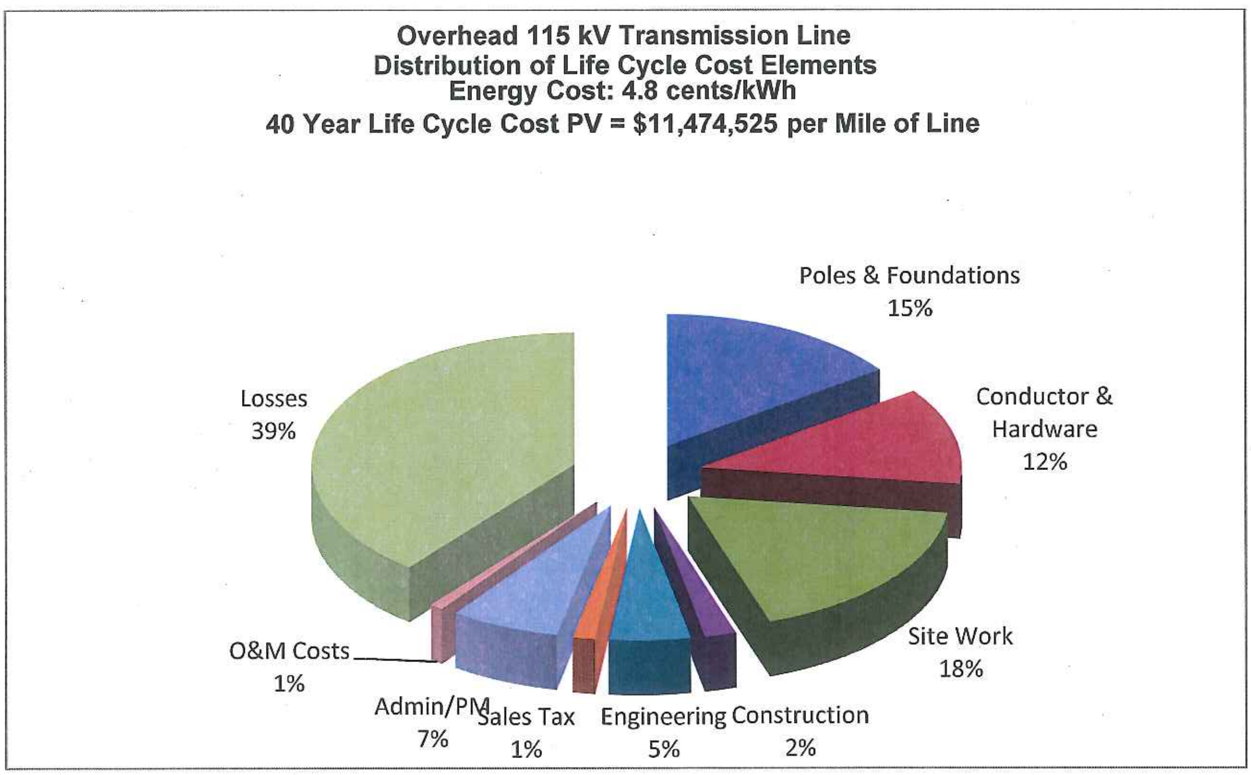


Figure 1-2: Life-Cycle Costs for a Typical 345 kV Overhead Line

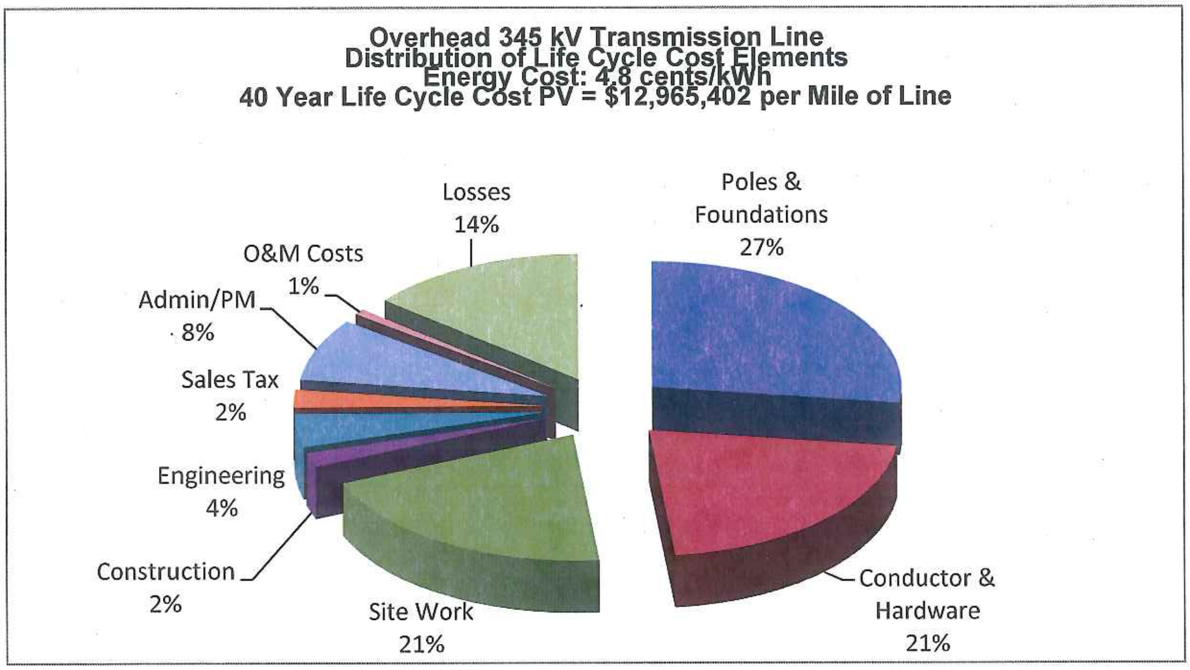


Figure 1-3: Life-Cycle Costs for a Typical 115 kV Underground Line

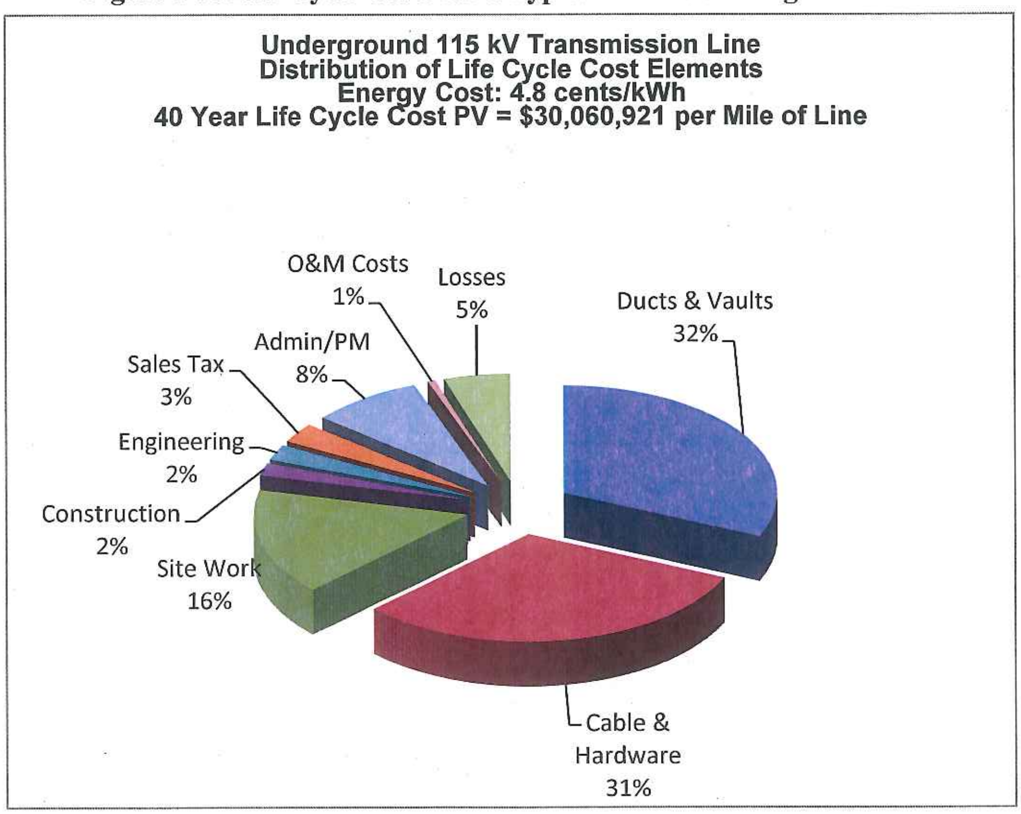
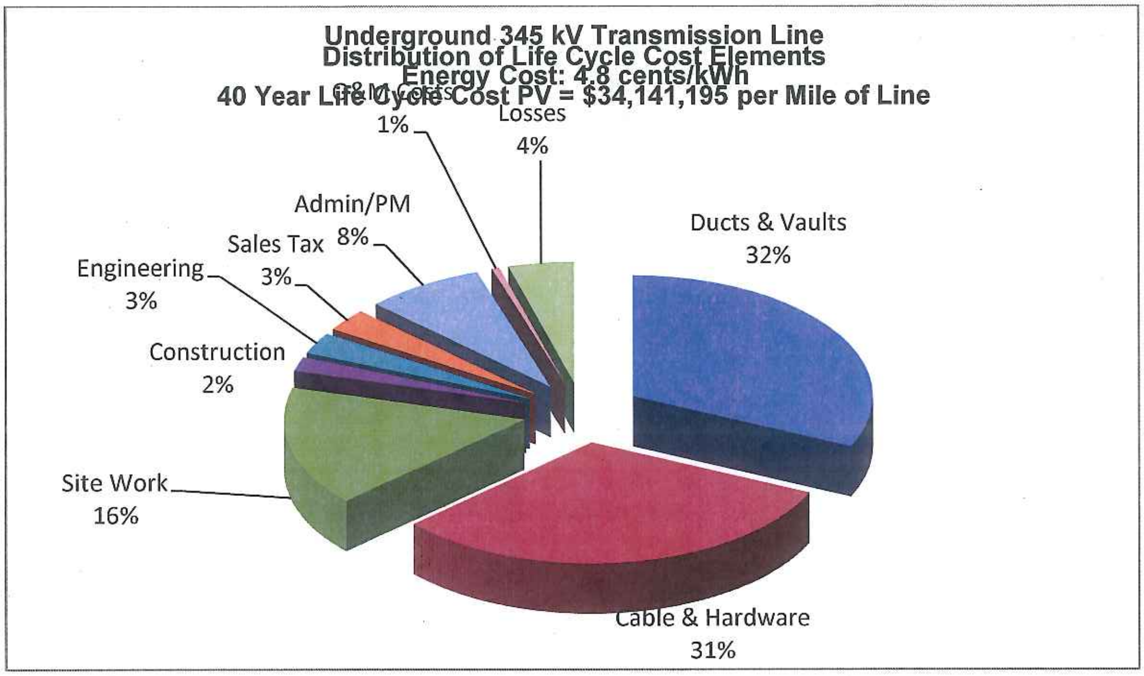


Figure 1-4: Life-Cycle Costs for a Typical 345 kV Underground Line



References:

1. Barringer, H. Paul and David P. Weber 1996, "Life Cycle Cost Tutorial", Fifth International Conference on Process Plant Reliability, Gulf Publishing Company, Houston, TX.
2. Connecticut Siting Council, RE: Life-Cycle 2006, Investigation into the Life-Cycle Costs of Electric Transmission Lines, January 12, 2006, Hearing Transcript page 15.
3. Connecticut Siting Council, RE: Life-Cycle 2012, Investigation into the Life-Cycle Costs of Electric Transmission Lines, November 15, 2011, Hearing Transcript pages 15-16.
4. http://www.iso-ne.com/markets/hstdata/znl_info/hourly/index.html

2. First Costs of Transmission Lines

2.1 Introduction

Transmission systems provide the physical means to transport bulk electric power and constitute an essential link between producers and consumers of electric energy. The transmission system consists of a network of transmission lines in which normally more than one transmission line is connected to each line termination, thus providing redundancy. For the purpose of identifying the first costs of representative transmission lines in the State of Connecticut, this report includes all capital, installation and permitting costs associated with the transmission line itself, except for the transmission line terminations and associated equipment (switchyard equipment, protection and controls, etc.). Electric power can be transmitted between any two geographical locations by overhead transmission lines, underground transmission lines, or a combination of the two. The first costs of overhead and underground transmission lines are presented in the following two sections.

2.2 Overhead Transmission

Overhead transmission lines are located above the ground level and are easily seen by the general public. Consistent with the National Electrical Safety Code (NESC), different designs of overhead transmission lines are built to meet different purposes. Some of the factors that are included in the design of an overhead transmission line are voltage level, type of supporting structure, and number of circuits per supporting structure. Generally, a single-circuit AC transmission line consists of three current-carrying conductors, one for each phase of a 3-phase AC system. These conductors are made of stranded aluminum or a mix of stranded aluminum and steel, and are electrically isolated by the surrounding air. The transmission line voltage is the magnitude of the electric potential difference between any two of its current-carrying conductors, normally referred to as the "line-to-line" voltage or simply "line voltage." The voltage is usually expressed in kilovolts or kV. One kilovolt is equal to one thousand volts. However, since 345 kV lines typically use two or more conductors per phase, known as "bundled conductors," the line voltage exists between two separate phases, not simply between any two conductors. The voltage across two conductors of the same phase is zero because they are at the same electric potential.

In the State of Connecticut, the most common overhead transmission line voltages are: 69 kV, 115 kV, and 345 kV. Because of their limited electric power capacities, 69 kV transmission lines are being phased out over time. Therefore, this report addresses the first costs of 115 kV and 345 kV overhead transmission lines. In overhead transmission lines, the current-carrying conductors are supported by insulators. The conductors and insulators are mechanically supported by structures, which are made from different designs and materials, such as wood or steel. The conductors and insulators of overhead transmission lines can be attached to the supporting structures in different arrangements according to specific design requirements. Similarly, transmission lines can have more than one circuit on a single supporting structure.

A large number of different overhead transmission line designs are used in the U.S. In Connecticut, however, the major utilities have provided four common transmission line designs that are the most likely to be built in the future. Therefore, this report addresses the first costs of these four designs only. These costs differ significantly from the 2007 report, however, because the designs investigated in the previous report were based on the use of ACSR conductors, whereas these four designs all employ ACSS conductors. In addition, these first costs have changed since 2007 due to changes in the costs of materials, fuel, and labor. First costs will be discussed in more detail in Section 3. Table 2-1 shows the key characteristics of the four overhead transmission line designs that would likely be considered for future use in the State of Connecticut.

Table 2-1: Characteristics of Common Overhead Transmission Line Designs in Connecticut

Voltage (kV)	Conductor Size and Type	Supporting Structure	Configuration	No. of Circuits	See Drawing
115	1272 kcmil ACSS	Wood Pole H-Frame	Horizontal	1	A-2
115	1272 kcmil ACSS	Steel Poles	Delta	1	A-1
345	1590 kcmil ACSS (bundled)	H-Frame	Horizontal	1	A-2
345	1590 kcmil ACSS (bundled)	Steel Poles	Delta	1	A-3

As shown in Table 2-1, the conductor configurations for overhead transmission lines in Connecticut are Delta and Horizontal. These names are common terminology within major utilities and relate to the physical appearance of the transmission line.

The major electric utilities in Connecticut identified wood and steel as the primary structural materials for the line designs listed in Table 2-1. The companies also confirmed that they no longer use lattice steel structures except for river crossings and hard-angle structures. [1] The designs listed in Table 2-1 are for single-circuit lines only.

In order to present the full range of first cost information for the overhead transmission line designs listed in Table 2-1, a cost breakdown by costing accounts is necessary. The accounts used for this purpose are established and defined by the Federal Energy Regulatory Commission (FERC) and are included in the FERC Uniform System of Accounts.

These accounts include the following listed below.

- Poles/Foundations — includes all labor, materials, and expenses incurred in the acquisition and installation of structural components.
- Cable/Hardware — includes all labor, materials, and expenses incurred in the conductors, insulators, and associated items (including cable splices).
- Site Work — includes all labor, materials, and expenses incurred in clearing and preparing the land.
- Construction — includes all labor, materials, and expenses incurred during construction including but not limited to foundations, erecting the structures, stringing the conductors.
- Engineering — includes all labor, materials, and expenses incurred in engineering activities.
- Sales Tax (4.13 percent) — includes the "blended" Connecticut sales tax rate, which is applied to the aggregate cost of taxable and tax-exempt purchases of services, equipment, and materials from suppliers and contractors[2].
- Project Management — includes all labor, materials, and expenses incurred in project administration. All permitting costs are included in this costing account.

The costs of land and land rights are not included in the above accounts. These costs are highly variable, site and project specific, and constitute one of the key factors that affects the overall cost. This will be discussed in greater detail in Section 3.

The first costs for single-circuit 115 kV overhead transmission line designs are listed in Table 2-2. These costs are per unit of transmission line length (United States dollars/circuit mile), and are based on the information provided by Connecticut Light and Power (CL&P) [3,4] with adjustments by KEMA [5].

Table 2-2: First Costs for Single-Circuit, 115 kV Overhead Transmission Lines

Cost Item	Line Design Supporting Structure / Conductor Configuration	
	Wood Poles / Horizontal	Steel Poles / Delta
Poles/Foundations	$615,350	$1,457,321
Cable/Hardware	$777,600	$838,874
Site Work	$961,450	$1,476,882
Construction	$135,500	$136,536
Engineering	$198,924	$487,100
Sales Tax (4.13 percent)	$70,309	$111,906
Project Management	$556,267	$362,381
Total Cost/Mile	$3,315,400	$4,871,000

From Table 2-2, one can see that the use of steel poles for single-circuit 115 kV overhead transmission lines has a significantly higher cost of poles and foundations, along with site work. The use of steel poles results in a 46 percent higher total cost per mile when compared with wood poles. Steel poles require concrete foundations whereas wood H-frame structures do not. This accounts for most of the additional cost.

The first costs for two 345 kV overhead transmission line designs are listed in Table 2-3. These costs are per unit of transmission line length (USD/circuit mile), and are based on the information provided by CL&P [3] with adjustments by KEMA [5]. A 345 kV H-Frame structure with horizontal conductor spacing results in a 42 percent lower cost per mile when compared to using a single steel pole structure with a Delta configuration. CL&P has indicated that it is their preference to use steel poles for 345-kV H-frame structures. Wood laminate structures are also an option. The cost difference between steel and wood laminate for 345-kV H-frame structures is relatively small.

Table 2-3: First Costs for Single-circuit, 345 kV Overhead Transmission Lines

Cost Item	Line Design Supporting Structure / Conductor Configuration	
	H-Frame / Horizontal	Steel Poles / Delta
Poles/Foundations	$1,356,200	$2,818,800
Cable/Hardware	$1,473,100	$1,810,400
Site Work	$1,448,250	$1,695,300
Construction	$136,150	$147,350
Engineering	$271,060	$385,740
Sales Tax (4.13 percent)	$136,411	$219,721
Project Management	$600,029	$637,489
Total Cost/Mile	$5,421,200	$7,714,800

2.3 Underground Transmission

Underground transmission lines are located below the ground level and are not easily seen by the general public. As with overhead lines, there are several different designs for underground transmission lines that are built for various purposes. A number of factors are considered in the design of underground transmission lines, including voltage, type and size of cable technology, type of installation, and number of circuits. As with overhead lines, a single-circuit AC underground transmission line typically consists of three current-carrying conductors, and the magnitude of the electric potential difference between any two of them constitutes the transmission line voltage.

Due to the reasons mentioned previously regarding the 69 kV transmission lines, this report addresses the first costs of 115 kV and 345 kV underground transmission lines.

The conductors for underground transmission lines are cables consisting of a central core (usually copper) surrounded by electrical insulation. Different technologies for transmission cables are based on the type of insulation that surrounds the copper core. The insulation medium can be a fluid, a compressed gas, or a solid dielectric. Examples of different insulation media include: for a fluid, kraft paper impregnated with mineral oil; for a gas, sulfur hexafluoride; and for a solid dielectric, cross-linked polyethylene. Cables can be installed underground in different ways. Normally, the cables are located inside steel or PVC ducts that are immersed in thermal sand or lean mix concrete and contained by a concrete trench. Inside this underground concrete trench, the ducts and conductors can be laid in different arrangements and can have single or double circuits according to specific design requirements for the type of installation.

There are a number of different underground transmission line designs in the US. In the State of Connecticut, the major utilities have identified four transmission line designs that are representative of underground transmission lines either currently in service or under construction. This report addresses the first costs of these four designs only. They are based on two cable technologies: high pressure fluid filled pipe type cable (HPFF), and cross-linked polyethylene cable (XLPE).

Table 2-4: provides characteristics of the four underground transmission line designs representing those used in the State of Connecticut.

Table 2-4: Characteristics of Common Underground Transmission Line Designs in Connecticut

Voltage (kV)	Cable Size and Type	Conductor Configuration / Cables per Phase	No. of Circuits	See Drawing
115	3000 kcmil HPFF	Delta / One cable per phase	1	A-4
115	3000 kcmil XLPE	Horizontal / One cable per phase	1	A-5
345	3000 kcmil HPFF	Delta / One cable per phase	1	A-4
345	3000 kcmil XLPE	Horizontal / One cable per phase	1	A-5

As mentioned previously, the cost of land is not included in first costs but is discussed in Section 3.

The first costs for 115 kV underground transmission lines are listed in Table 2-5.

These costs are per unit of transmission line length (USD/circuit mile), and are based on the information provided by CL&P [3] with adjustments by KEMA [5].

Table 2-5: First Costs for Single-Circuit 115 kV Underground Transmission Lines

Cost Item	Line Design Cable Size / Configuration - Cables per Phase	
	3000 kcmil HPFF Delta - One cable per phase	3000 kcmil XLPE Horizontal - One cable per phase
Duct/Vaults	$5,314,590	$6,009,792
Cable/Hardware	$4,566,056	$6,573,210
Site Work	$2,694,722	$3,004,896
Construction	$299,414	$375,612
Engineering	$374,267	$659,121
Sales Tax (4.13 %)	$468,283	$697,350
Project Management	$1,253,345	$1,939,134
Total Cost/Mile	$14,970,677	$21,970,700

Table 2-5: shows that for single-circuit 115 kV underground transmission lines the total XLPE cable system cost is 46 percent higher per mile than for the HPFF cable system. This reverses the findings of the 2007 report. XLPE cable system costs have risen at a much steeper rate than HPFF cable systems during the past 5 years, and this is shown in the data. HPFF cables have not really been built in the past 5 years, however, so the costs may not reflect the most recent data.

The first costs for single-circuit 345 kV underground transmission lines are listed in Table 2-6. These costs are per unit of transmission line length (USD/circuit mile), and are based on the information provided by CL&P [3] with adjustments by KEMA [5]. Generally, the first costs for 345 kV underground with two cables per phase would be almost double that of one conductor per phase.

Table 2-6: First Costs for Single-Circuit 345 kV Underground Transmission Lines

Cost Item	Line Design Cable Size / Configuration - Cables per Phase	
	3000 kcmil HPFF Delta - One cable per phase	3000 kcmil XLPE Delta / Horizontal - One cable per phase
Duct/Vaults	5,905,100	7,030,624
Cable/Hardware	5,073,396	7,689,745
Site Work	2,994,135	3,515,312
Construction	332,682	439,414
Engineering	499,023	659,121
Sales Tax (4.13 %)	520,314	697,350
Project Management	1,309,436	1,939,134
Total Cost/Mile	16,634,086	21,970,700

The data in Table 2-6 show that the total cost per mile of a single-circuit XLPE cable system is 32 percent higher than for an equivalent HPFF cable system at 345 kV.

Additional investigation shows that "splice vaults" and other costs related to the cable installation have a big impact on this increase. When two cable segments need to be joined, large and costly concrete enclosures called "splice vaults" are installed below the ground level to protect the cable joints. The dimensions of these splice vaults are approximately 27 feet long x 8 feet wide x 8 feet high (See Figure 2-1).

Figure 2-1: Typical 345 kV XLPE Splice Vault (Under Construction)

The material and labor costs of burying these splice vaults are significant. The splice vaults used for XLPE cable systems are physically larger than the ones used for HPFF. Furthermore, a 345 kV double-circuit underground transmission line with one cable per phase would require six of these splice vaults every mile for an XLPE cable system. For HPFF cable systems, however, only two splice vaults per mile would be required. Other factors are related to the vault's location (i.e., on the road, or off the road on private property), and the amount of excavated soil that has to be disposed of in an environmentally-friendly manner. These factors can add many millions of dollars to the cost of XLPE duct vault installations. These will be discussed further in Section 4.

In addition to these first costs for underground cables, other costs relate to accessories required for the proper operation of cable systems, such as pressurization plants and shunt reactors. These accessories and their associated costs are discussed in Section 5.

While overhead transmission is significantly different from underground transmission in many aspects and one-to-one comparisons are not always possible, a key observation is that the total cost per mile of an underground 345 kV transmission line can be six to eight times higher than the total cost of an overhead 345 kV transmission line. Not only first costs, but a number of other factors provide the basis for this significant cost difference. These factors are discussed further in Section 3.

References:

1. Northeast Utilities System, Response to Connecticut Siting Council Request for Information for Docket No. LIFE-CYCLE 2011, Connecticut Siting Council Investigation into the Life-cycle Costs of Electric Transmission Lines, January 17, 2012, Hearing Transcript pages 10 and 60.
2. Sales Taxes in the State of Connecticut are 4.6% of all material purchases.
3. Northeast Utilities System, Response to Connecticut Siting Council Request for Information for Docket No. LIFE-CYCLE 2011, Connecticut Siting Council Investigation into the Life-cycle Costs of Electric Transmission Lines, Interrogatory Set 3, Q-CSC-002, December 14, 2011.
4. Northeast Utilities System, Response to Connecticut Siting Council Request for Information for Docket No. LIFE-CYCLE 2011, Connecticut Siting Council Investigation into the Life-cycle Costs of Electric Transmission Lines, Interrogatory Set 3, Q-CSC-003, December 14, 2011.
5. KEMA Engineering Consultants made adjustments to the cost data provided to make some of the first-cost components align more closely with previously reported numbers. Material Costs, Site Work, and Total Cost were taken as provided, but adjustments were made to Sales Taxes, Engineering, and Project Management costs to provide a better comparison with the 2007 report.

3. Key Factors Affecting First Costs

3.1 Introduction

The previous section presented the basic component for any transmission line life-cycle cost calculations—the first costs. This section presents the key factors that affect these first costs, which include:

- Transmission line ROW
- Permitting and legal requirements
- Land and land rights
- Materials, labor, and associated cost escalation
- Electric and magnetic field (EMF) mitigation

These factors are all interrelated. Each of them has a role in any project, but the weight of each one is very project specific. While these factors are not all-inclusive, they represent a selected list of factors that need to be considered as variables that can influence the first costs. Furthermore, these factors can provide some basis for the significant cost difference between overhead and underground transmission lines.

EMF mitigation is included in the list of key factors above, but will be discussed in more detail in Chapter 9 of this report.

3.2 Transmission Line Right-of-Way (ROW)

The term "right-of-way" (ROW) generally has two meanings. The first one relates to the corridor of land over which facilities such as highways, railroads, or other utility infrastructures are built. The second one relates to the right to pass over property owned by another party. Combinations of the two in a given application are also possible. For transmission lines, the ROW usually includes the area of land in which the transmission line structures are located and the additional areas around the transmission line required for its proper operation and maintenance. Occasionally, and particularly in urban areas, the right to pass over specific property owned by a third party is part of the transmission line ROW.

There are many variables that relate to a transmission line ROW and affect transmission line costs. The most relevant variables are the types of terrain, obstacles along the ROW, and the level of development near the ROW. The impact of these variables on transmission line design and its possible effect on costs are discussed.

3.2.1 Types of Terrain

In this discussion, we consider five basic types of terrain: flat, rolling, mountainous, rocky, and wetlands. The impact that the different types of terrain may have on the overhead and/or underground transmission line designs and associated costs include:

- Incremental length of the transmission line to avoid difficult types of terrain;
- Incremental number of stronger structures and foundations for terrain with different elevations, i.e., rolling terrain;
- Incremental labor for foundations in rocky terrain;
- Special foundations and taller/stronger structures for water crossings; and
- Incremental costs of access road construction in difficult terrain.

Flat and dry terrain provides the ideal scenario, and serves as the baseline for analyzing the impact of types of terrain on the transmission line designs. Rolling terrain may result in higher costs associated with stronger structures and foundations that are required between two contiguous towers at significantly different elevations. Steeper terrain is generally not suitable for underground cables or conduit systems, which is why underground cables are not commonly sited off road right-of-ways in Connecticut. Mountainous terrain increases costs by necessitating stronger structures and foundations; also, transmission line length may increase to avoid passing through steep mountainous areas.

Wetlands are typically environmentally sensitive areas and the transmission line span may increase to avoid passing through this type of terrain. If the transmission line needs to span over longer than normal distances due to wetlands, larger foundations and taller structures are typically required, resulting in higher costs.

Rocky terrain, common in Connecticut, may present particular challenges. Breaking rock by mechanical methods is the first choice; however, blasting may be required to install structure foundations for overhead transmission lines or to excavate the cable trench and manholes/splice vaults required for underground transmission lines. For blasting and rock removal, special procedures must be followed to assure compliance with Connecticut regulations. Excavated material that cannot otherwise be used at the site has to be removed and properly disposed of elsewhere. Underground cable installation typically involves the excavation of a trench about 4 feet wide and 5 feet deep, as well as areas (every 1,500 – 2,000 feet) for manhole or splice vaults that are about 27 feet long by 8 feet wide and 8 feet high. Based on the recent Bethel-Norwalk 345 kV transmission project, more than twenty-five percent of the trench excavation has been in rock. Rock excavation can be almost four times more expensive than soil excavation[2].

Based on CL&P's experience with the underground portion of the Bethel to Norwalk project and UI's environmental and test pit surveys along its portion of the route of the Middletown-Norwalk project, estimates for trench excavation due to rock and soil disposal have both been increased[3].

The degree to which terrain affects costs is very project-specific, but experience with difficult terrain does allow cost impacts to be estimated. According to the study titled "Transmission Line Capital Costs", prepared for the US Department of Energy[4], the incremental cost per mile for rolling terrain is 10 percent of the total capital costs. CL&P has seen 100-200 percent increases in foundation costs in areas that have large rock formations, as compared to the costs of foundations in more agricultural types of land[5].

3.2.2 Obstacles along the ROW

A second factor is related to obstacles that may be encountered in specific locations along the transmission line ROW. In this discussion we consider four types of obstacles:

1. private houses, schools, public buildings and parks
2. rivers and streams
3. roads and railways
4. other infrastructure or utilities

Since these obstacles typically are not spread over a wide geographical area, their impact on costs tends to be small when compared to factors related to the type of terrain. The impact that these obstacles may have on the overhead and/or underground transmission line design and the associated costs include:

- Incremental length of the transmission line to avoid obstacles
- Incremental number of stronger structures and foundations for road crossings
- Special foundations and taller/stronger structures for water crossings
- Incremental labor for installation of underground lines due to the presence of other utilities

To avoid private houses, schools, public buildings and parks, the transmission line length may have to increase. Rivers and streams are typically environmentally-sensitive areas, and the transmission line span/length may also have to increase to avoid them. If the transmission line needs to cross rivers or streams, the longer spans require taller, stronger transmission structures and associated larger foundations, both of which lead to increased costs.

Different types of structures are built for different purposes. On most lines, the majority of structures are suspension structures that carry the conductor on either a straight line or a very shallow angle (5˚-10˚); the structures, insulators and associated hardware are not designed to resist the full tension of the wires. Sharper bends (up to 45˚) require stronger angle structures in which the insulators and associated hardware are most robust, but are not capable of resisting the loss of all the wires on one side. At each end of the line, and periodically along its length, dead-end structures are used. Unlike suspension and most angle structures, dead-end structures are designed to withstand the unbalanced load carried in the event that all the conductors on one side go slack[6].

Wherever an overhead transmission line needs to cross a road, stronger structures and foundations are required, because of the longer spans. Underground utilities may also impact the design of underground transmission lines, since additional labor and materials may be required to avoid conflicts.

The impact that the different kinds of obstacles may have on costs will be proportional to the incremental length of the line needed to avoid them, or the incremental costs of stronger/taller structures and foundations. Thus, cost impacts are very project-specific.

3.2.3 Level of existing development near the ROW

In this discussion we consider three basic levels of existing development near the transmission line ROW: urban, suburban, and rural. The impact existing development may have on the overhead and/or underground transmission line designs and its associated costs include:

- Incremental length of the transmission line due to additional number of turns in the transmission line route
- Incremental number of stronger structures and foundations (dead-end and angle structures) due to additional number of turns in the transmission line route
- Taller structures with larger concrete foundations due to narrow ROW in urban/suburban areas

A number of the implications of building a transmission line in an urban/suburban area were noted by CL&P. With the degree of urban and suburban land development that are encountered, especially in Southwest Connecticut, existing transmission line routes take many turns to avoid densely developed areas. Each turn requires more dead-end and angle structures, which in turn causes the line length to increase. Tall steel structures, and especially dead-end and angle structures, require much larger poles and foundations, resulting in significantly higher material and construction costs[5]. Transmission construction in urban areas within the State of Connecticut is frequently confined to a narrow ROW that can only accommodate vertically-configured lines on taller steel poles.

The impact that existing development near the ROW may have on costs will be related to the specific details of the suburban/urban area and the characteristics of the ROW within these areas, which will determine the number of turns that need to be made. Therefore, the absolute impact in cost due to increased transmission line length and due to the incremental number of taller and stronger structures and foundations is very project specific.

3.3 Permitting and Legal Requirements

Utilities' permitting costs are broad in nature, and include but are not limited to the following: development of permit applications, environmental reports and maps; permit/certificate application filing fees; support of the permit applications at agency hearings; and preparation of plans and/or studies that may be required for permit approval[6]. While the utilities in Connecticut do not separately track permitting costs, they agree that the costs related to permitting have increased during recent years and they believe that trend is expected to continue.

Most utilities now have Community Outreach programs and public relations organizations that hold public meetings to explain transmission development and environmental management plans at open houses. Meetings and permits are required with the United States Army Corps of Engineers (USACE), the Department of Energy and Environmental Protection (DEEP), the Connecticut Siting Council (Council), and Native American Tribal representatives.

Utilities building transmission facilities in the State of Connecticut are facing more public scrutiny of their plans and practices, as well as increased permitting and review requirements, and have experienced increased costs as a result. The ISO New England also has a formal process of studying transmission options to meet FERC reliability requirements that can sometimes lead to lengthy reviews.

While ISO-NE is not an entity regulated by the State of Connecticut, its analysis of regional transmission development is an important component of the utility's transmission planning and siting process.

Many variables in the permitting and legal requirements for transmission lines affect transmission line costs. We have identified the most relevant government entities that affect transmission line siting, design, and associated costs. Those government entities include: the Council, the Connecticut Department of Transportation (CDOT), DEEP, and the USACE.

3.3.1 Connecticut Siting Council (Council)

The Council has jurisdiction over the siting of power facilities and transmission lines in Connecticut, and evaluates utility applications for those facilities and lines. When conceptualizing the addition of a new transmission line to the power system, utility system planners perform many planning and preliminary engineering activities. This work ultimately leads to the development of an application to the Council for a new line. In addition to the details of the proposed line, the application includes a set of alternative solutions that have been evaluated by the utility in an effort to confirm that the proposed line represents the optimum solution. Criteria for determining the best solution typically include system benefit (reliability and operability), technical feasibility (ability of a project to be engineered and built), property impact (social perception), environmental impact, and cost. The application by the utilities is the first step in a statutorily defined permitting process[7].

On June 2004, the Connecticut Legislature enacted Public Act 04-246, "An Act Concerning Electric Transmission Line Siting Criteria." In basic terms, PA 04-246 requires the Council: 1) to maximize the technologically feasible lengths of new underground 345 kV transmission lines in areas of certain land uses, and 2) to apply the best management practices for electric and magnetic fields for electric transmission lines. The impact of this Public Act on new 345 kV overhead and/or underground transmission line designs and associated costs includes:

- Incremental length of the underground segments for transmission lines in certain land uses;
- Incremental length of the transmission line (overhead and underground);
- Use of more expensive XLPE cables, instead of HPFF;
- Increased complexity and costly time for planning and siting transmission lines;
- Increased number of underground-overhead transition stations; and
- Potentially increased project cost due to requirements for significant magnetic field management measures.

Although PA 04-246 requires the use of underground 345 kV designs only in certain defined areas where technologically feasible, utility companies seeking to build new facilities will, in fulfilling their obligation to manage costs, invest substantial effort to develop alternative designs and to evaluate the technical and financial viability of such underground construction and its alternatives.

Since the 2007 report on life-cycle costs was published, the Connecticut Legislature enacted Public Act 07-4, which amended PA 04-246 to make clear that, in considering the feasibility of underground transmission lines pursuant to the Act, the Council should consider "whether the cost of any contemplated technology or design configuration may result in an unreasonable economic burden on the ratepayers of the State."[8]

3.3.2 Connecticut Department of Transportation (CDOT)

The mission of the CDOT is to provide a safe and efficient transportation system for the people traveling in Connecticut. In order to accomplish this mission, the CDOT works with the public, transportation partners, State and federal legislators, and other State and local agencies[9]. The CDOT has direct responsibility for the efficient operation of ground transportation such as railways, State roads, and even local streets in urban areas. When a transmission ROW is located near roadways, railways or rights of way that fall under the CDOT jurisdiction, special procedures must be followed. CDOT requirements and regulations can affect underground transmission line designs for installations in rural, urban, and suburban areas. CDOT requirements may result in:

- Incremental costs for easements over private property because construction within the highway ROW for utility facilities such as splice vaults is not permitted
- Incremental costs for horizontal directional drilling or self-supporting structures to cross water bodies and other features, when attachment of cables to bridges is not allowed
- Work schedule restrictions

Specific examples of the type of impact CDOT requirements can have on project costs are summarized below.

Vault location

As stated in a previous section, the physical dimensions of the splice-vaults for 345 kV XLPE cables are considerable. Because the installation of these splice vaults can require road closures with an estimated time of up to three weeks, the CDOT has decided as many vaults as possible must be built off the roadway. (CL&P notes that most of the time spent on vault work is for splicing, not burying the vault.) This requirement imposes considerable added costs, including obtaining easements over private property adjacent to the road, the cost of turning the cable ducts off of and then back on to the road at each vault, the cost of the crossing of more buried utilities, and, ultimately, as cable length increases, the cost of additional vaults.

The number of splice vaults is, in part, a function of the lengths of the cables. The length of the transmission cables is limited to the weight and size of a cable coil that can be transported on typical roadways.

Working schedule

In order to not disturb roadway traffic, CDOT has decided that contractors working on underground transmission lines in State roads are allowed to work only during the night shift. This may have impacts in costs since the working hour window for labor at the site may be reduced to 6-8 hours due to the considerable set-up and clean-up time required for each shift[2].

Cable installations along bridges and special construction methods

Historically, the attachment of transmission cables to highway bridges or other State structures crossing water bodies and/or railroads has not been supported by CDOT. Special construction methods such as horizontal directional drilling or "jack and bore" are the alternatives. In horizontal directional drilling, a pilot hole is drilled and then reamed out to an appropriate size and the duct or pipe is pulled into the hole. Jack and bore involves the construction of pits on either side of the obstacle; a small tunnel is built while simultaneously a pipe is installed as the tunnel is formed.[10] These methods normally place the cables at greater depths, a minimum of 15 feet below the surface, and may require significant environmental impact controls and associated costs. Furthermore, cable capacity decreases with cable depth. This is another limiting consideration for underground cable systems.

The degree to which these design changes imposed by CDOT affect costs is very project-specific, but generally these requirements may cause an increment of 10 to 20% on the construction costs for underground transmission lines[2].

3.3.3 Connecticut Department of Energy and Environmental Protection (DEEP)

The mission of DEEP is to conserve, improve and protect Connecticut's natural resources and environment while ensuring a clean, affordable, reliable and sustained energy supply.[11] When a transmission line ROW is located near an environmentally sensitive area under DEEP jurisdiction, special procedures must be followed. DEEP requirements and regulations can affect underground transmission line designs for installations in rural, urban, and suburban areas. One significant impact of DEEP requirements on the incremental costs of construction has to do with the management of excavated soil materials.

Contaminated Soil

Since some of the soil under the roads in the State of Connecticut can be contaminated, the DEEP requires that the excavated soil not be reused to close underground cable trenches and must be stored according to special rules.

3.3.4 U.S. Army Corps of Engineers (USACE)

The USACE is responsible for investigating, developing and maintaining the nation's waterways and related environmental resources. When a transmission line ROW is located near waterways under the USACE jurisdiction, special procedures must be followed. The impact of USACE requirements includes increased project lead-time and permitting costs. Normally, for the permits required from the USACE, a final design is needed. The USACE does not allow project segmentation in this permitting process. These permits, which may take a year or even significantly longer to obtain, are typically done in connection with other permits granted by the Council and/or DEEP. Therefore, it may add to the total project time and have a direct impact on the project costs.

3.4 Land and Land Rights

As mentioned before, the first costs information included in this section do not include the costs of land and land rights. In some US states, and particularly within rural areas, these costs are relatively small and may not be significant when compared with material and labor costs. According to the study titled "Transmission Line Capital Costs", prepared by the US Department of Energy[4], 5.5 percent of the materials (cable, structures, etc.) costs would be enough to cover land and land rights in a non-urban area.

According to the utilities in Connecticut, however, the costs of land and land rights are quite significant and therefore deserve extensive review.

The impact of the cost of land and land rights on overhead and/or underground transmission line project cannot be over-emphasized. *These costs can be the decisive factor to build a transmission line either underground or overhead.* The cost of land for transmission ROW is site-specific and can actually alter the proposed route or preferred line design. Project cost estimates (including ROW costs), for the Milford-Norwalk section of the Middletown-Norwalk 345 kV transmission project were only a little higher for the underground line option because the land costs associated with an overhead line option were much higher than the land costs for the underground option.

The costs associated with land and land rights are both highly variable and very project-specific. Regarding the specific land cost differences in Connecticut, recent estimates indicate that for the Bethel-Norwalk 345 kV transmission project an acre of land near Bethel, a suburb of Danbury, costs approximately $100,000 USD, whereas for Norwalk the cost is $350,000 USD. In this project, one of the alternatives required widening the ROW by 40-50 feet, and the estimate for land acquisition was 50 million dollars.[12] Twenty (20) miles for fifty (50) million dollars is $2.5 million dollars per mile. Comparing this $2.5 million per mile with the other capital costs for 345 kV overhead transmission lines, we can see that the land costs become one of the largest components of the overall capital costs, along with structures and foundations. For underground transmission lines, however, $2.5 million per mile of land represents the fourth largest component, after ducts/vaults, cable/hardware, and site work.

3.5 Materials, Labor, and Cost Escalation

Once a transmission line design has been completed, an estimated materials list is defined. Similarly, construction estimates have detailed lists for the expected labor hours required to build the transmission line. Since transmission projects may take one to seven years to complete, there may be a significant increase in first costs simply due to the cost escalation of materials and labor over time.

The cost escalation for materials and labor depends on many social and economic variables. Some of the factors that drive these cost escalations include high demand for raw materials like steel and fuel, limitations of manufacturing capability for large items like cables and tubular steel structures, and labor and material shortages.

There are significant differences in the amount of materials and labor required to build an overhead as opposed to an underground transmission line. Underground construction requires significantly higher material costs as a percentage of total project cost than overhead construction. Also, most of the underground line cost data represents transmission lines in Southwest Connecticut, and this is a costly area to construct transmission due to its population density and urban nature.

Since the 2007 report, the labor vs. material percentage of the total project cost has increased dramatically, from 35 to 45 percent for overhead lines, and from 24 to 31 percent for underground lines.

References

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2. Northeast Utilities System, Response to Connecticut Siting Council Request for Information for Docket No. LIFE-CYCLE 2006, Connecticut Siting Council Investigation into the Life-cycle Costs of Electric Transmission Lines, Question-CSC-005, January 10, 2006.
3. United Illuminated, Response to Connecticut Siting Council Request for Information for Docket No. LIFE-CYCLE 2006, Connecticut Siting Council Investigation into the Life-cycle Costs of Electric Transmission Lines, Question-CSC-005, January 10, 2006.
4. K.R. Hughes and D.R. Brown, "Transmission Line Capital Costs", Pacific Northwest Laboratory, prepared for the US Department of Energy under contract DE-AC06-76RLO 1830.
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6. "Life-cycle Costs Study for Overhead and underground Electric Transmission Lines", ACRES International Corporation, July 1996.
7. Connecticut Siting Council, RE: Life-Cycle 2006, Investigation into the Life-Cycle Costs of Electric Transmission Lines, January 12, 2006, Hearing Transcript page 43.
8. Northeast Utilities System, Response to Connecticut Siting Council Request for Information for Docket No. LIFE-CYCLE 2011, Connecticut Siting Council Investigation into the Life-cycle Costs of Electric Transmission Lines, Interrogatory Set 1, Q-CSC-015, September 15, 2011.
9. http://www.ct.gov/dot/cwp/view.asp?a=1380&Q=302028.
10. Connecticut Siting Council, Findings of Facts, Docket No. 272, "345 kV electric transmission line between Middletown and Norwalk", April 7, 2005.
11. http://www.ct.gov/deep.
12. Connecticut Siting Council Technical Meeting, RE: Life-Cycle 2006, Investigation into the Life-Cycle Costs of Electric Transmission Lines, March 14, 2006, Hearing Transcript page 94.

4. Cost Differences among Transmission Technologies

The cost to design, build, operate, and maintain an overhead transmission line is lower than the cost of an underground equivalent due to basic cost differences in materials and construction methods. Also, the technology of overhead transmission is less complex than that of underground transmission and therefore requires less in the way of special equipment or facilities to operate the transmission system. The various types of overhead structures and line configurations, as well as the different types of underground cable can impact total project costs significantly.

4.1 Electrical and Operating Characteristics of OH and UG Lines

A basic issue in the design of a transmission line is the difference in electrical characteristics between overhead and underground line designs and the need to compensate for those differences. For example, overhead and underground lines differ greatly in their electrical inductive and capacitive reactance. Inductance and capacitance are properties of an electric circuit that relate to the voltage induced in a circuit by an alternating current (inductance) and the charge on the conductors per unit of potential difference between them (capacitance).

The cables in underground lines also have lower impedance than the bare conductors in overhead lines, and therefore are susceptible to higher fault currents (short circuits), which could potentially damage the cable. Mitigations for this type of problem in UG system design include installing a series reactor to reduce fault currents or using higher-rated circuit breakers.

Another difficulty with UG system design is that underground lines have a higher capacitance than overhead lines due to the closer proximity of the conductors to one another. When a line is energized, the capacitance can cause the line voltage to rise above acceptable limits and excess voltage must be controlled or canceled. Devices called shunt reactors are often installed for this purpose. While high capacitance is a normal characteristic of an underground line, it does result in additional costs to a project.

When needed, shunt reactors are installed at the facilities where overhead/underground transitions are made, called "transition stations." Transition stations are discussed in a little more detail in the following section on hybrid lines. Because a shunt reactor is physically located in a transition station, it is not technically considered to be part of the transmission line itself. However, because the line design creates the need for the shunt reactor, the cost of that equipment is appropriately considered as part of the first cost of the transmission line and included when evaluating an underground alternative. According to CL&P, a typical shunt reactor costs around $6.5 million[1]. Transition stations are discussed in a little more detail in the following section on hybrid lines.

4.2 Hybrid Lines

A hybrid line is a single-circuit of one voltage that consists of both overhead and underground sections over the course of the line route. Such construction is called "porpoising" the line, because the line travels above and below the surface, the way a porpoise swims at sea.

There can be many viable reasons for a line to be designed and constructed in this manner. The most obvious reasons are associated with the line routing and the difficulty that may be involved in building certain segments of a line overhead. Rough terrain, dense urban development, unsuitable subsurface conditions, bodies of water and any other number of obstacles may cause these difficulties. It should be stated that engineering technology exists to build a line in most any configuration desirable at any location. Therefore, a hybrid line is sometimes the most feasible option for line construction at a reasonable cost.

An overhead line requires switching stations or substations at each end of the line. An underground line requires similar terminal stations at each end of the line. A multi-conductor per phase 345-kV hybrid line, however, may require terminal facilities at each point where the line changes from overhead to underground and again to overhead. So the first costs of a hybrid line, in addition to the fundamentally higher cost of underground construction, would also increase by the additional cost of transition stations.

Transition stations also require the acquisition of land and may result in increased costs for associated environmental impacts. The issues of land and land rights for transmission line projects are discussed in Section 3 of this report.

When the Bethel-Norwalk line was originally proposed by CL&P in 2003, project estimates created for three different alternatives indicated that the most expensive alternative was a hybrid line, as opposed to fully overhead or underground alternative. For the hybrid line option, $20 - $25 million of the additional cost was for the transition stations and the shunt reactors required to accommodate by the hybrid design.[2]

4.3 New and Emerging Transmission Technologies

As the need for more transmission capacity increases throughout the State of Connecticut, as well as the entire country, new technologies are being introduced to facilitate the higher throughput of energy. These technologies are being used in both retrofit applications to existing lines and initial design elements of new lines. These technologies include materials and systems devices such as FACTS, HVDC transmission and HTLS composite conductors. Each has benefits in certain line applications and can increase transmission capacity.

4.3.1 FACTS and Typical Costs

FACTS (Flexible Alternating Current Transmission System) incorporate electronic-based controllers with other standard power system components to enhance transmission system control and increase power transfer capability. Problems created in transmission networks today by uncontrolled power flows and voltage transients have created a need for more dynamic regulation of networks to reduce the likelihood of power transfer bottlenecks and blackouts. FACTS devices can be used for dynamic voltage control and for steady-state power flow regulation. FACTS devices and the primary applications for them are included in Table 4-1.

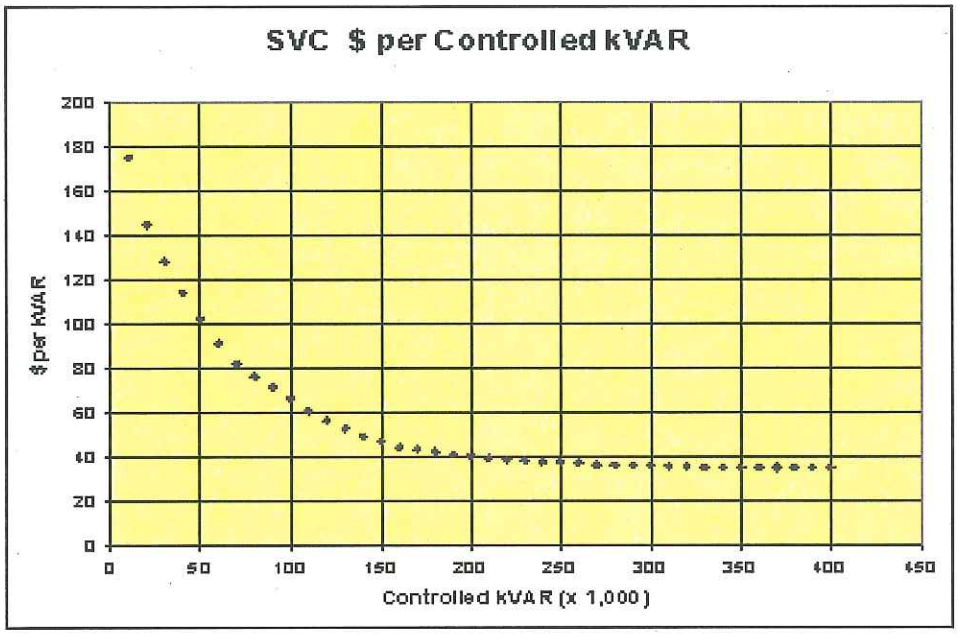
Table 4-1: Primary applications of FACTS devices

FACTS APPLICATIONS				
FACTS Equipment	Dynamic voltage stability	Power flow control	Voltage unbalance compensation	Reduction of short-circuit level
Static VAR Compensator (SVC)	X	X	X	
Static Synchronous Compensator (STATCOM)	X	X	X	
Thyristor Controlled Series Compensator (TCSC)	X	X		
Unified Power Flow Controller (UPFC)	X	X		X
Interphase Power Controller (IPC)		X		X

Among the various FACTS devices, only an SVC or STATCOM would have a direct application in the State of Connecticut. CL&P currently has just one, a fully-redundant 75 MVAR STATCOM device (150 MVAR total) located at the Glenbrook Substation. This is the only one in the State and was installed in 2004 at a cost of $15.6 million[3]. Installation of FACTS devices is becoming more widespread across the country as system capacity limitations create problems under the slightest contingency.

The cost of FACTS devices depends mostly on their size, but technical characteristics, control functions and application are all influencing factors. FACTS controllers (e.g. SVC, STATCOM, etc.) for larger transmission projects (i.e., capacities of 200 MVAR and higher), are usually applied at voltage levels of 138kV and higher, are in the range of $40 to $50/kVAR. Smaller FACTS installations are more expensive on a $/kVAR basis. These would be systems less than 100 MVAR and applied at industrial facilities or on utility distribution systems of 69 kV and below. A chart of these relationships is shown below for a Conventional Static VAR Compensator (SVC) in Figure 4-1.

Figure 4-1: SVC System Cost vs. Size (Controlled kVAR)



Source: Electric Power Initiative White Paper on Power Electronics Technologies [12]

Advanced STATCOM (Voltage-Sourced Converter) system costs are about 20 percent higher than a conventional SVC for the same size. However, the MVAR required for a STATCOM in a given installation can be about 10-20 percent less than what is required to meet the same performance as a conventional SVC[4].

4.3.2 High Voltage Direct Current (HVDC) Typical Costs

HVDC transmission systems involve the conversion of alternating current (AC) power to direct current (DC) for the purpose of transmitting the power over long distances, typically hundreds of miles. Shorter applications are also feasible depending upon the specific requirements. A recent example in the State of Connecticut is the Cross Sound cable, a 40 km, 330 MW, ±150 kV HVDC cable connecting Connecticut with Long Island, New York. The cable connects the 345 kV transmission system at New Haven to the 138 kV system at Shoreham Generating Station on Long Island.

HVDC is used for special purposes such as connecting asynchronous AC systems or for connecting remote hydro or wind power to the grid.

HVDC has the following characteristic benefits:

- Controllable – power can be injected where needed
- Carries more power over the same ROW, thus fewer lines
- Bypasses congested circuits – no inadvertent flow
- Requires only two instead of three conductor sets
- Has unlimited distance stability
- Demands reactive power only at terminals
- Has fewer losses over long distances

A major disadvantage for HDVC systems, however, is the need for convertor stations at each end of an HVDC line where it joins the AC system.

HVAC and HVDC are not equal technical alternatives. Each potential application of HVDC must be evaluated in comparison to an AC circuit to meet the same need. HVAC and HVDC are not equal technical alternatives. For overhead applications, long-distance, point-to-point power transfers are an application where HVDC may be the only reasonable alternative. For underground or submarine applications, the high capacitance and the resulting costs of an AC circuit may create the possibility for HVDC to be cost-competitive and operationally preferred. The Cross Sound cable is an example. However, the high cost of terminal converter stations required for HVDC often offset any potential savings compared to an AC line. Only long-distance applications tend to overcome this cost addition. Distances required for a break-even comparison between AC and HVDC are generally around 30 miles for submarine cable and may be as much as 300 miles for overhead. HVDC systems in North America address either a long-distance, asynchronous or undersea cable application.

The potential use of HVDC transmission as an alternative was discussed in the Solution Report for the Interstate Reliability Project, dated August, 2008. In that report, the HVDC option "E" of the New England East-West solution considered a 1,200 MW HVDC line from National Grid's Millbury Station to CL&P's Southington Substation. The two 1,200 MW converter stations would have cost $536M (in 2008 dollars). That alternative was "the first option eliminated because it offered fewer system benefits than most AC options at a greater cost[5]."

The above-mentioned factors make it unlikely that either an overhead or underground HVDC line will be installed within the State of Connecticut as a direct alternative to an AC line. Therefore, the life-cycle costs of such lines are not addressed in this report.

4.3.3 High Temperature, Low Sag (HTLS) and Composite Conductors

The transmission industry in recent years has seen the introduction of new conductor materials that bring the benefit of higher current-carrying capacity, lower weight and greater strength-to-weight ratios than materials generally used for transmission lines in the past. Composite conductors are regarded as a potential re-conductor solution to line congestion and loading issues at a reasonable cost of installation.

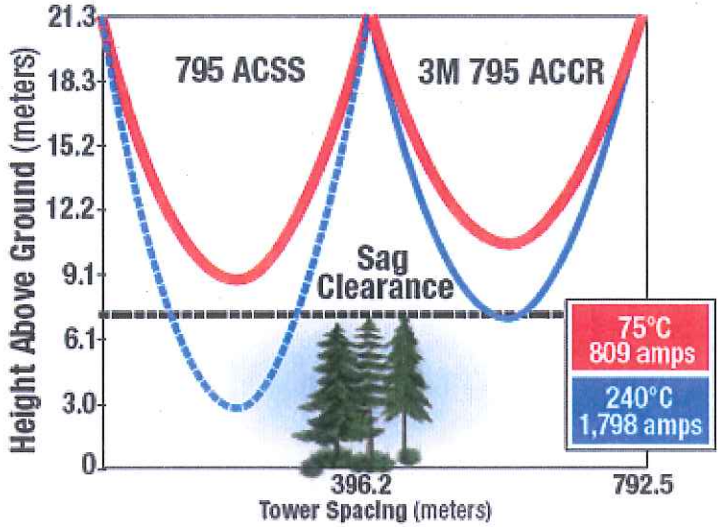
Composite conductors use a core of composite materials as the mechanical support component of the conductor and stranded aluminum conductors as the exterior, current-carrying component. The composite core replaces the steel core found in most conductors today. Benefits to be gained from the use of composite conductors as compared to steel-core conductors include:

- Higher current-carrying capacity and operating temperature
- Higher strength-to-weight ratio
- Less conductor sag at a given load
- Less conductor sag at a given load, leading to reduced tower heights
- Lower construction costs for towers and foundations

The standard type of conductor used in transmission-line construction today is Aluminum Conductor, Steel-Reinforced (ACSR). It has been used throughout the utility industry for decades and is not HTLS. Aluminum Conductor, Steel-Supported (ACSS), while not a composite conductor, is classified as HTLS, and is a major improvement over standard ACSR. Aluminum Conductor, Composite-Reinforced (ACCR) as its name states, is a composite conductor and was developed by the 3M Corporation and the U.S. Department of Energy (DOE) with the specific goal of creating an HTLS conductor. To accomplish this, ACCR utilizes aluminum-oxide core strands and composite fibers as the strengthening material to form a fiber-reinforced metal matrix. Aluminum Conductor, Composite-Core (ACCC) is very similar to ACCR but uses a total aluminum-oxide composite core.

An illustration of reduced conductor sag using HTLS conductors is shown in Figure 4-2. In this illustration, the "sag clearance" shown above ground is increased by the use of HTLS conductors that sag less under the same loading conditions for the same ACSS and ACCR conductor size.

Figure 4-2: Illustration of reduced sag and increased clearances using composite conductors



Source: 3M Corporation

CL&P has adopted ACSS HTLS as their standard conductor for future overhead transmission line construction. While ACSS conductors are more expensive than ACSR conductors (the previous standard), they also sag less, operate at higher temperatures, and have more current-carrying capacity, as mentioned previously. This offers the benefit of reducing some structure heights, and thereby reducing costs associated with structures and foundations. The cost savings of reducing some structure heights would likely be offset by the higher conductor cost. CL&P anticipates that ACSS will perform better than ACSR over the transmission life-cycle[6].

UI remains committed to the continued use of ACSR as their standard conductor for overhead transmission lines. UI acknowledged that they have not recently completed construction of an overhead transmission line but have collaborated with CL&P on recent transmission line cost estimates and defer to CL&P when it comes to all overhead transmission line construction and first costs[7]. Therefore, all transmission line first costs used in this report are based on data provided by CL&P.

Table 4-2 shows a cost comparison between ACSR conductor and the three HTLS conductors presented in this section. This comparison is based on conductor price only, one conductor per phase, and does not include special hardware, fittings, or installation.

Table 4-2: Conductor Cost Comparisons

Conductor Price Comparison			
Conductor Type	Size	Cost ($/K-ft.)	Cost ($/mile)
ACSR	1272	$3,154.80	$49,972.03
	1590	$4,282.88	$67,840.82
ACSS	1272	$3,580.00	$56,707.20
	1590	$4,439.20	$70,316.93
ACCR	1272	$15,774.00	$249,860.16
	1590	$21,414.40	$339,204.10
ACCC	1272	$17,900.00	$283,536.00
	1590	$22,196.00	$351,584.64

Source: ALCAN Product Catalog, January, 2012

Notes: **1. Cost in $/K-ft. are for single wire, while $/mile are provided for a 3-phase AC line.**

2. ACCR and ACCC prices estimated.

As mentioned previously, the higher cost of composite conductors would be offset by a reduction in some tower costs due to lower conductor sag. Maximizing the capacity of new and existing transmission lines with reduced tower heights is obviously a desirable goal for transmission line owners and operators across the country, and the utilities in the state of Connecticut have made strides in that direction by adopting the use of ACSS conductors. A presentation of transmission life-cycle costs is presented in Section 9.2 comparing ACSR and ACSS conductors.

4.3.4 Superconducting Cable Technology

American Superconductor Corporation (AMSC), along with Long Island Power Authority (LIPA), Nexans, and the Department of Energy (DOE) energized the world's first commercial high-temperature superconducting (HTS) transmission-voltage power cable in 2008. The 138 kV HTS system consists of three (3) individual HTS power cables that run in parallel. The name "high-temperature" means that these cables can operate at 90 degrees Kelvin, or -183 degrees C (-297 degrees F), and therefore require a great deal of energy to cool the cables. This also limits distance. The prototype system has demonstrated attributes of high current capacity (4,000 amps) and current-limiting capability.

Much of the superconducting cable technology is under development by the Department of Homeland Security (DHS). Their interest in superconducting cables lies in developing high-reliability "super-grids" that are impervious to failures and terrorist attacks. Together with AMSC, Southwire, Praxair, and Consolidated Edison, the DHS Resilient Electric Grid Project has installed 300 meters of Inherently Fault Current Limiting (IFCL) superconductor cable in New York City. There are also similar commercial superconducting cables in operation at DOE demonstration projects in a few other places around the country. These superconducting cable systems are very expensive and have limited high-reliability applications due to their extremely high cost. The HTS cable costs are proprietary and on a project-specific basis and, as such, are prohibitively expensive on a commercial scale at this development stage. There are currently no superconducting cables operating in or planned for the State of Connecticut because of the cost and current state of the technology.

An example of the new Triax superconducting cable is shown in Appendix Figure C-3.

4.3.5 Life-cycle Cost Impact of Transmission Technology

The preceding discussion explores some of the technologies that are currently available for consideration in design and construction of transmission lines. However, transmission lines are designed and engineered to meet the requirements of specific circumstances of load and location and as such, are customized for the situation. It follows that life-cycle costs associated with a particular line are specific to that line design and location. While typical costs can be used for estimating purposes, the final costs will be dependent upon the technology used to meet the need identified and will be unique to that project.

In Section 9, there is a presentation of the cost impact of alternative conductors in transmission life-cycle cost analysis, by comparing ACSR and ACSS conductors.

References:

1. Northeast Utilities System, Response to Connecticut Siting Council Request for Information for Docket No. LIFE-CYCLE 2011, Connecticut Siting Council Investigation into the Life-cycle Costs of Electric Transmission Lines, OCC-006, October 21, 2011.
2. Connecticut Siting Council, RE: Life-Cycle 2011, Investigation into the Life-Cycle Costs of Electric Transmission Lines, January 12, 2006, Hearing Transcript, page 51.
3. Northeast Utilities System, Response to Connecticut Siting Council Request for Information for Docket No. LIFE-CYCLE 2011, Connecticut Siting Council Investigation into the Life-cycle Costs of Electric Transmission Lines, Supplemental Information, February 24, 2012.
4. Reed, Gregory; University of Pittsburgh, Swanson School of Engineering; "Electric Power Initiative White Paper on Power Electronics Technologies (draft)," January, 2012.
5. Solution Report for the Greater Springfield Reliability Project, August 2008.
6. Northeast Utilities System, Response to Connecticut Siting Council Request for Information for Docket No. LIFE-CYCLE 2011, Connecticut Siting Council Investigation into the Life-cycle Costs of Electric Transmission Lines, Interrogatory Set 2, Q-CSC-017, October 21, 2011.
7. United Illuminating, Response to Connecticut Siting Council Request for Information for Docket No. LIFE-CYCLE 2011, Connecticut Siting Council Investigation into the Life-cycle Costs of Electric Transmission Lines, Interrogatory Set 2, Q-CSC-015.

5. Transmission Loss Costs

5.1 General

Since no device is 100 percent efficient, there will be a certain amount of loss associated with any movement of power through an electrical component, thus lowering the output of power flow.

A significant amount of the variable component in life-cycle costs for transmission lines may be attributable to the losses incurred during operation of the line. In addition to the magnitude of the load current, many factors have a direct bearing on the loss cost calculation.

5.2 Load Losses in Transmission Lines

The losses in a transmission line are fundamentally resistive losses due to an electric current passing through a conductor. Transmission line losses increase in direct proportion to the line resistance and in proportion to the square of the line current (in amperes). Because line resistance increases as operating temperature increases due to increases in line current, the magnitude of load losses can vary greatly between peak load and light load conditions. The transmission grid is operated in a very flexible manner where individual line loadings can vary greatly or even reverse from one hour to the next depending on many factors such as generator dispatch, network configuration, or system disturbances.

5.3 Costs

There are two basic cost components of electrical energy losses from transmission. One is an energy cost component, and the other is a demand charge component.

- Energy costs are associated with the consumption of fuel and related expenses required to generate the energy that is lost.
- Demand (capacity) costs are the costs associated with the need for keeping additional generation available. This type of cost is usually based on the magnitude of losses occurring at the system peak.

Energy costs can be determined on an incremental or average system cost basis, depending on the cost assignment approach taken. The incremental approach utilizes the concept of "marginal cost", that is, the cost of supplying the next unit of energy required during the course of time considered. The average cost approach is based on the average energy costs occurring during the course of the year.

The incremental approach is often seen to be more accurate than the average approach for the following reasons:

- It is typically considered to be more theoretically correct since the losses to be evaluated represent an incremental addition to the existing load.
- Incremental costs are typically much higher than average costs, and a significant amount of load losses occur during high load conditions when the energy costs are the highest.
- Some users will adopt energy costs associated with nearby generating units, especially if the lines are connected to switchyards at plant sites. Others will consider all losses to be incremental in nature and use the same costs system wide. Since transmission lines represent a portion of the "bulk system" that are used to serve the needs of the entire electric system, the incremental approach to the cost of losses is deemed to be more representative of the true total system cost.
- Capacity (demand) costs can be treated as incremental or average also. They can also incorporate the timing of new generation and/or transmission by calculating the NPV associated with an advancement of an installation date of a planned addition caused by the additional losses. Demand costs were not used in the calculation of transmission loss costs for this report.

5.4 Contributing Factors to the Cost of Losses

Several factors influence the cost of losses in a given transmission line, including:

- Line length – the resistance of the line increases proportionally with the length of the line.
- Conductor type & size – different types of conductors have different resistive characteristics. Generally, the larger the conductor, the lower the resistance.
- Load magnitude – as mentioned above, the losses due to the load vary with the square of the load current.
- Loss factor – defined as the average loss / peak loss. This factor represents the level of uniformity of the loss over the given period of time, usually one year. Since the loss varies with the square of the load, as load increases, the loss factor increases by the square of the load increase, and the loss costs increase accordingly.
- Load growth – the higher the load growth, the greater will be the NPV of the cost of losses. For this report update, a load growth of 2.03% was used. [1], [2]
- Generating unit type – energy and demand costs vary widely for various types of generation. Hydro, wind, and solar all have extremely low energy costs, while coal and gas units have much higher energy costs.
- Voltage level – no-load losses will vary depending on the level of the operating voltage.

References:

1. DOCKET NO. 2010/2011 – Connecticut Siting Council Review of the Ten-Year Forecast of Connecticut Electric Loads and Resources, Final Report dated September 8, 2011, p. 6
2. The 2.03 percent load growth is based on a weighted average of CL&P, UI, and CMECC's projected total distribution loads plus system losses. As an approximation, transmission load growth is assumed to be similar, on average.

6. Operating and Maintenance Costs

6.1 General

After a transmission line is constructed and energized, many tasks that must be performed, either routine or as-needed, in order to ensure economical, safe, and reliable performance. Two major categories for these tasks are: 1) operating, and 2) maintenance.

6.2 Operating Costs

The fundamental principles of electric power system operation emanate from the fact that electricity cannot be easily stored. Electrical energy must be consumed as it is being produced, requiring the generation output to match the customer demand on a continuous basis. This is a complex process involving many decisions and actions each day by experienced personnel. It also is an important part of each electric utility's program to ensure the economic, reliable, and safe delivery of power throughout the system.

Operation of an electric power transmission system has two principal goals:

- Supply power to customers reliably
- Transport power to customers economically

These two goals must be achieved while adhering to requirements for system safety and reliability overall. All system components must operate within their thermal ratings; system voltages must remain within acceptable limits; and that all generators connected to the system must be synchronized. Moreover, these requirements must be met in a dynamic environment. The electric system is frequently exposed to disturbances of varying severity, including short-circuits, failure of transmission line components, or failure of generating units. For example, short circuits that cause breaker lockouts change load flow patterns, frequently resulting in increased loading or abnormal voltages on critical circuits. Operators must decide how to alleviate these conditions if established limits are exceeded. Similarly, failure of transmission or generation components can result in load or voltage changes that must be corrected to avoid further system problems.

In addition to abnormal situations as described, normal environmental changes in weather, time of day, or off-system demand for power purchases create load fluctuations that must be monitored and managed by operations personnel. The system is designed and built to handle certain contingencies, but the system operator must be able to recognize and react to developing conditions in a timely fashion.

The major costs associated with the operation of the transmission system can be grouped into five classes:

- Those associated with the operation of substation equipment;
- Those associated with the technical control of the transmission system (performed by ISO-NE for safety and reliability purposes), with administrative transaction costs;
- Those incurred as a result of constraints on the operation of the power transmission system which may result in running less economical generating units;
- Those associated with losses (see Section 5 for more information); and
- Property taxes paid to local governing districts for transmission facilities located within their jurisdictions.

Operating costs include the labor costs and expense items required to physically execute routine operational activities: including allocating loads to plants and interconnections with other companies; directing switching operations to take certain equipment out of service for construction and maintenance or for load management; controlling system voltages; load-testing of circuits; and various inspection and analysis activities associated with line operations. System operations personnel also perform administrative tasks such as creating and updating the system records required for operations, maintenance and regulatory purposes.

These are routine activities that occur frequently as a result of predictable, common activities, including the administrative, record keeping, and switching activities due to cyclical or seasonal changes in system conditions. On the other hand, work associated with significant non-routine activities, such as line overloads, generating unit or major transmission forced outages, or storm conditions can also occur. In addition to spending large amounts of time and money on switching and coordinating system recovery, personnel must then conduct special studies to deal with the new system conditions.

6.3 Maintenance Costs

Proper line maintenance is required to achieve optimum levels of service reliability. A highly reliable transmission line begins with sound design, including mechanical, dielectric, and thermal aspects; good construction practices to minimize installation problems; and high-quality materials, including conductors, structures, hardware, and splices. Once constructed and put into service, transmission line reliability and performance is then dependent upon good maintenance practices, with appropriate time intervals and techniques.

Good maintenance practices include field inspection, repair, and period replacement of aged components. Utilities in the State of Connecticut have also adopted aggressive new transmission vegetation management plans (TVMP) and new technologies in overhead transmission line maintenance, as follows.

- More patrols are required on 345 kV circuits, as regulated under NERC Transmission Vegetation Management Standard FAC-003-1. Previously, these lines were patrolled only once per year. Under the new TVM Standard, these patrols are now performed three times per year.
- LiDAR surveys of NERC – designated transmission lines have been initiated and are currently scheduled on a three-year cycle. These surveys have increased maintenance expenditures by $1,500 per mile of line in 2008 (the initial flights and data acquisition) and are projected to add $500 per mile of surveyed line every three years. These surveys are limited to 345 kV lines.
- Increased inspections are being performed for high-risk trees off the ROW that could fall into transmission lines.
- Increased efforts are being made to remove tall-growing red cedar trees in areas under the lines that are subject to North American Electric Reliability Corporation (NERC) Transmission Vegetation Management Standard FAC-003-1 (NERC TVM Standard FAC-003-1).

These programs have increased annual transmission line O&M costs. They have been implemented to improve transmission line reliability and decrease future line maintenance costs associated with line outages and vegetation management.[1]

6.3.1 Overhead transmission line maintenance

Transmission line maintenance tasks are specifically designed to reduce the probability of occurrence of the most common types of outages. Common maintenance tasks are focused on periodic inspection of the structural and electrical components of a line and the routine care of vegetation and access ways along the ROW on which the line is constructed.

Structural and electrical maintenance activities include:

Routine maintenance activities include:

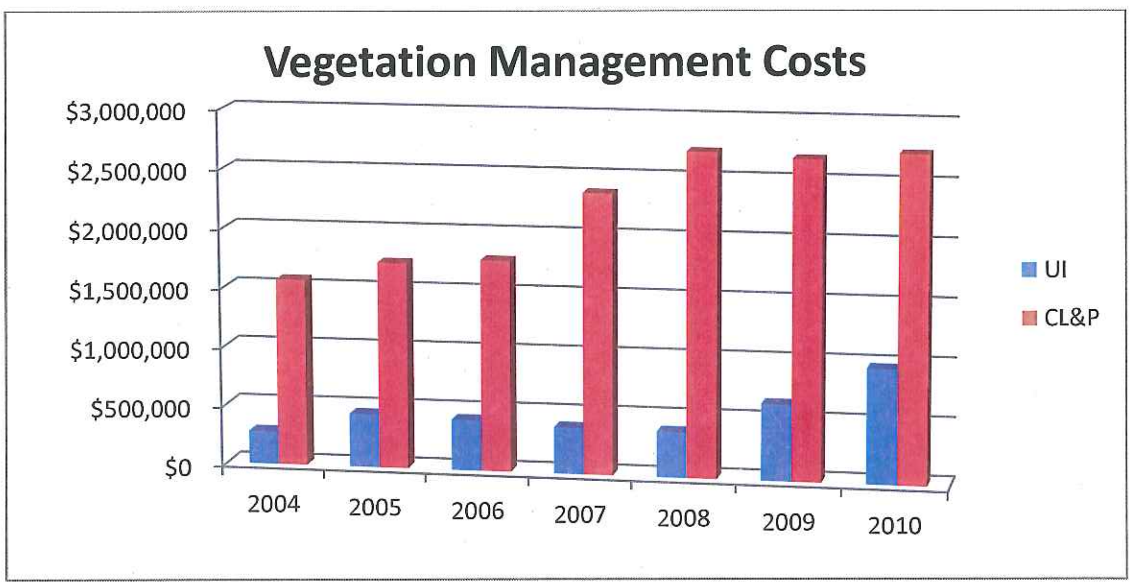
- Climbing inspections, performed at intervals based on age, deterioration, reliability history, and criticality
- Foot patrols to allow visual inspection of both structural and electrical components
- Helicopter patrols to identify components that may be deteriorated or damaged
- Wood pole inspection, testing and treating, typically performed on a frequency interval based on reliability indicators, such as failure rates, level of deterioration experience encountered, line criticality, and cost considerations
- Wood pole replacement, typically performed after inspection / treatment activities; program typically starts with replacing those on critical lines with higher outages or older poles;
- Steel pole repainting
- Infrared inspection to identify hot spots on splices and connectors

Vegetation management is a cyclical process that provides for periodic clearing of trees, brush and other vegetation that could interfere with proper operation of the transmission line. Vegetation management is scheduled periodically for any given line or line segment, with the frequency determined by operating history and budgetary requirements. Vegetation management activities may include the following:

- Mowing the ROW;
- Side-trimming trees along the edge of the ROW;
- Removing trees within the ROW;
- Removing trees that are outside the limits of the ROW but due to their size and condition represent a high risk of falling into the transmission line;
- Performing LiDAR aerial patrols of the ROW; and
- Applying herbicides to control vegetative growth. (Many companies use herbicide treatments on ROWs to inhibit fast-growing species of grasses, weeds and trees. The utilities in the State of Connecticut also her herbicides for transmission ROW vegetation control, but they do not use growth retardents.[1,2,3,4]

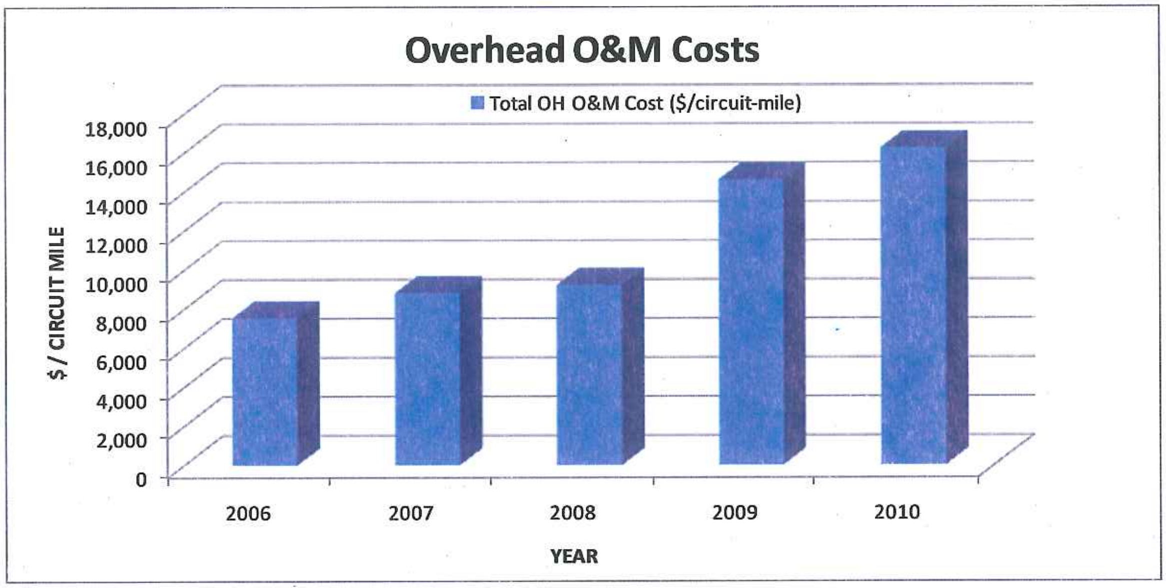
Utilities in the State of Connecticut have indicated that transmission vegetation management plans necessary to meet NERC Standard FAC-003-1 have greatly impacted transmission O&M costs. To illustrate this, the TVMP costs for each company from 2004 to 2010 are shown in Figure 6-1. This increase in line patrols and use of LiDAR (see Appendix) to meet NERC standards began in approximately 2007.

Figure 6-1: Transmission Vegetation Management Costs, 2004-2010



Many companies also use herbicide treatments on rights of way to inhibit the growth of fast growing species of grasses, weeds and trees. The utilities in the state of Connecticut use herbicides for transmission ROW Overhead transmission line maintenance costs in the State of Connecticut have been steadily growing over the past five years, with major increases in the last two years, as shown in Figure 6-2.

Figure 6-2: Total Overhead Transmission Line O&M Costs, 2006-2010



These O&M cost increases are primarily the result of the compliance with NERC VM Standard FAC-003-1 and the implementation of LiDAR patrols, which are discussed further in the Appendix.

6.3.2 Underground transmission line maintenance

Even though some transmission lines are located underground, a considerable amount of routine maintenance still must be performed to ensure that the underground system performs reliably. Depending upon the type of underground system involved, maintenance can include the inspection and other required actions within underground vaults or transition stations as well as along the route of an underground line. Typical activities may include work associated with conduits; work associated with conductors and devices; retraining and reconnecting cables in manholes, including transfer of cables from one duct to another; repairing conductors and splices; repairing grounds; and repairing electrolysis prevention devices for cables.

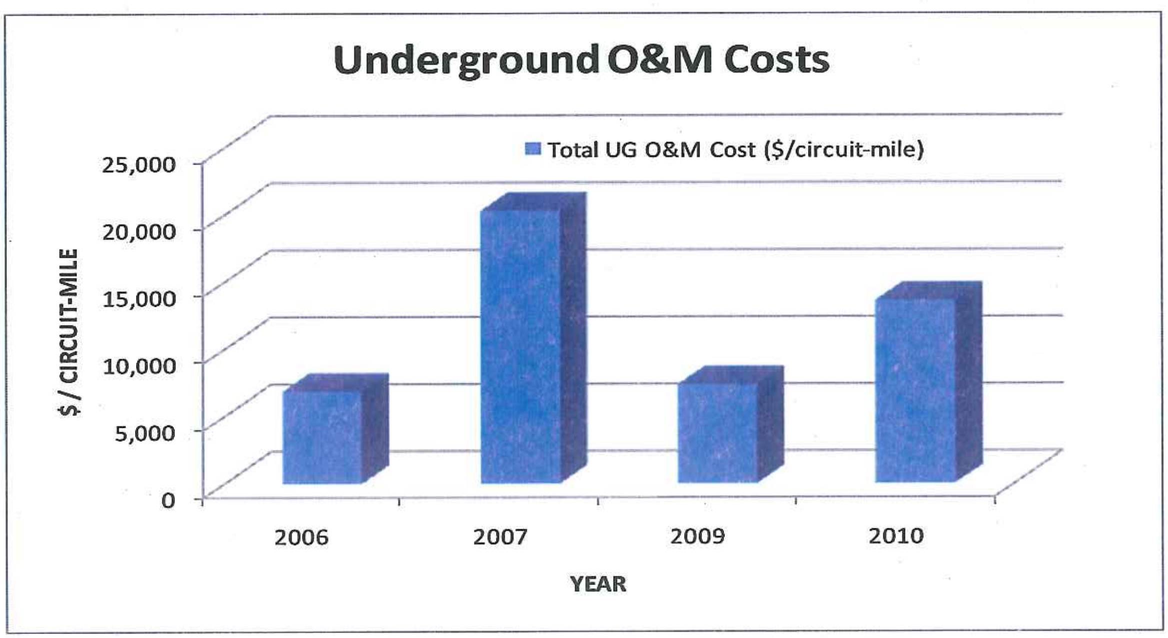
Maintenance of underground manholes and vaults includes cleaning ducts, manholes, and sewer connections; minor alterations of handholes, manholes, or vaults; refastening, repairing, or moving racks, ladders, or hangers in manholes or vaults; repairing sewers and drains, walls and floors, rings and covers; re-fireproofing cables and repairing supports; and repairing or moving boxes and potheads. Sheath-bonding equipment in XLPE splice vaults and cable-temperature monitoring systems also need to be maintained.

In the case of underground systems that are fluid-filled and pressurized, a considerable amount of maintenance is involved for the equipment in the fluid system. This includes pumps, reservoirs, piping, and valves. The fluid itself also requires maintenance in the form of testing, purifying, replenishing, or even replacing.

Because of the nature of underground systems and their design, safety restrictions can be an issue with maintenance activities. Space within vaults and manholes is limited, and depending upon the type of equipment being inspected or maintained, special protective measures for personnel may be required. These all add to the time and expense for the maintenance activity, whatever it may be.

Underground transmission line maintenance costs in the State of Connecticut have been very unsteady over the last 5 years, with major increases in 2007 and 2010, as shown in Figure 6-1 which provides the total underground O&M expenditures per circuit-mile in the State of Connecticut.

Figure 6-1: Total Underground Transmission Line O&M Costs, 2006-2010



The large increases in underground maintenance expenditures in 2007 and 2010 have occurred as a result of major cable repairs in 2007 and 2009.[5] The amounts shown in Even though some transmission lines are located underground, a considerable amount of routine maintenance still must be performed to ensure that the underground system performs reliably. Depending upon the type of underground system involved, maintenance can include the inspection and other required actions within underground vaults or transition stations as well as along the route of an underground line. Typical activities may include work associated with conduits; work associated with conductors and devices; retraining and reconnecting cables in manholes, including transfer of cables from one duct to another; repairing conductors and splices; repairing grounds; and repairing electrolysis prevention devices for cables.

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Underground transmission line maintenance costs in the State of Connecticut have been very unsteady over the last 5 years, with major increases in 2007 and 2010, as shown in Figure 6-1 which provides the total underground O&M expenditures per circuit-mile in the State of Connecticut.

Figure 6-1 do not include FERC Accounts 560 and 568, which deal with supervision. These accounts are discussed in Section 6.5.

6.4 Variability of Costs

O&M costs vary between utilities and from year-to-year for the following reasons:

- Age of the line – as indicated above, replacement programs for poles in later years will drive up the costs; also, replacements of hardware, splices, etc., have similar influences. Other maintenance activities will likely increase in frequency with age, including insulator washing, pole treatment, pole and guy adjustments, and ground maintenance.
- Weather impacts – the impact on costs will be huge during years having severe weather spells (ice, wind, thunderstorms) that result in major outages and damage to equipment.
- Reporting differences – accounting practices vary between utilities: FERC accounts (see Section 6.5 for FERC discussion), the primary guidelines for cost information, are vague in some instances, contributing to differences that could mislead anyone trying to compare utilities. Among these vagaries are the treatment of line terminal equipment, joint use land, conduits and poles between transmission and distribution, unit of property designations, and capital vs. O&M classification of replacement components/parts.
- Line length – when considering costs on a per mile basis, utilities with relatively short lines will look high, due to the fixed costs associated with many cost components, including engineering, overheads, and underground equipment. Both first cost and variable cost numbers may be distorted due to these factors.

Also contributing to O&M cost variations are proactive repairs and replacements, especially in older systems. Large projects involving repairs, upgrades, or replacements may be classified as O&M and could trigger large increases in spending. The return on such investments may be low in economical terms, but justifiable when considering reliability benefits. In such cases, utilities with higher investments in reliability improvements may look costly in comparison; however, a longer view may prove otherwise as reliability deficiencies manifest themselves in higher outage costs.

Even though some transmission lines are located underground, a considerable amount of routine maintenance still must be performed to ensure that the underground system performs reliably. Depending upon the type of underground system involved, maintenance can include the inspection and other required actions within underground vaults or transition stations as well as along the route of an underground line. Typical activities may include work associated with conduits; work associated with conductors and devices; retraining and reconnecting cables in manholes, including transfer of cables from one duct to another; repairing conductors and splices; repairing grounds; and repairing electrolysis prevention devices for cables.

Maintenance of underground manholes and vaults includes cleaning ducts, manholes, and sewer connections; minor alterations of handholes, manholes, or vaults; refastening, repairing, or moving racks, ladders, or hangers in manholes or vaults; repairing sewers and drains, walls and floors, rings and covers; re-fireproofing cables and repairing supports; and repairing or moving boxes and potheads. Sheath-bonding equipment in XLPE splice vaults and cable-temperature monitoring systems also need to be maintained.

In the case of underground systems that are fluid-filled and pressurized, a considerable amount of maintenance is involved for the equipment in the fluid system. This includes pumps, reservoirs, piping, and valves. The fluid itself also requires maintenance in the form of testing, purifying, replenishing, or even replacing.

Because of the nature of underground systems and their design, safety restrictions can be an issue with maintenance activities. Space within vaults and manholes is limited, and depending upon the type of equipment being inspected or maintained, special protective measures for personnel may be required. These all add to the time and expense for the maintenance activity, whatever it may be.

Underground transmission line maintenance costs in the State of Connecticut have been very unsteady over the last 5 years, with major increases in 2007 and 2010, as shown in Figure 6-1 which provides the total underground O&M expenditures per circuit-mile in the State of Connecticut.

Figure 6-1 shows the erratic nature of underground transmission O&M costs. There can be years without significant events impacting O&M Costs, but there can also be years like 2007, when necessary underground XLPE cable repairs proved to be quite costly. Another jump in O&M costs occurred in 2010 related to a cable failure and repair that began in 2009. For this reason, it can be somewhat difficult to use any one year as a basis for establishing "typical" O&M costs. The average of O&M costs over many years of data would more accurately represent a basis for projections. However, since there have been recent cost increases associated with more aggressive TVMPs, line patrols, and LiDAR surveys, an average over several years would not capture the improvements in these programs and their associated costs. Therefore, in this report, the 2010 O&M data was more heavily weighted.

6.5 O&M Cost Assumptions for Life-cycle Cost Analysis

Ideally, it would be useful to assign a specific O&M cost figure to each type of transmission line and to distinguish between 115 kV and 345 kV line costs for a specific line type. However, electric utilities do not account for their O&M costs on a line-by-line basis or on a voltage class basis. Instead, transmission O&M costs are assigned to certain standard cost accounts, as specified by FERC. The FERC accounts associated with Transmission Line O&M include:

560 – Operations Supervision & Engineering
563 – Overhead Line Expenses
564 – Underground Line Expenses
568 – Maintenance Supervision & Engineering

571 – Overhead Line Maintenance

572 – Underground Line Maintenance

For analyses involving underground lines, it has been noted that a significant and infrequently occurring event can distort maintenance costs in any given year, particularly for a small number of asset circuit-miles. Both CL&P and UI experienced significant cable failures in 2007 and 2009 with associated higher-than-normal maintenance costs related to those cable repairs. Therefore, an average of 2009 and 2010 O&M cost data was used as a basis for establishing current underground maintenance costs.

For analyses involving overhead lines, it was noted that recent cost increases associated with transmission vegetation management plan changes required to meet the NERC Standards could only be captured by using the 2010 data. The O&M Cost data reported by the two utilities for 2010 are shown in Table 6-1.

Table 6-1: FERC Records for Transmission O&M Costs

	2010	
Transmission Expenses	**UI**	**CL&P**
Operations		
560 Operation Supr & Eng	$1,626,511	$307,000
563 OH Lines Expenses	$57,686	$990,263
564 UG Lines Expenses	$23,250	$280,338
TOTAL OPERATION (UG + OH)	$487,564	$1,577,601
Maintenance		
568 Maintenance Supr & Eng	$115,829	$245,000
571 Maintenance of OH Lines	$1,198,229	$5,287,547
572 Maintenance of UG Lines	$36,452	$1,275,822
TOTAL MAINTENANCE (UG + OH)	$1,292,596	$6,808,369
Ckt Miles – OH	101.1	1638.0
Ckt Miles – UG	28.5	135.0
TOTAL O&M OH	$1,583,177	$6,713,890
TOTAL O&M UG	$196,982	$1,672,080
TOTAL O&M OH ($/ckt-mi)	$12,425	$3,833
TOTAL O&M UG ($/ckt-mi)	$2,098	$11,527
TOTAL OH O&M ($/ckt -mi)	**4,771**	
TOTAL UG O&M ($/ckt -mi)	**11,435**	

Notes: Source: CL&P and UI

1. For UI, only 25% of the total of Account 560 – Operation Supervision and Engineering – was allocated to Transmission Operations Expense. Of that amount, two-thirds was allocated to overhead operations, and one-third was allocated to underground operations. For CL&P, only the amount of Account 560 attributable to overhead operations was provided.
2. For UI, only 50% of the total of Account 568 – Maintenance Supervision and Engineering—was allocated to Transmission Maintenance Expense. Of that amount, 97 percent was allocated to overhead maintenance, and 3 percent was allocated to underground maintenance. For CL&P, only the amount of Account 568 attributable to overhead operations was provided.

Since the 2010 underground O&M costs were high compared to other years due to cable repairs, the average of 2009 and 2010 was used to arrive at an average base-year figure.

The resulting average base-year O&M cost figures for Connecticut transmission lines (in 2010 dollars) used for the life-cycle cost calculations were:

- Overhead line O&M 4,771 $/circuit-mile
- Underground line O&M 8,739 $/circuit-mile

These averages are more heavily weighted toward the CL&P figures, since they have more installed transmission circuit miles than UI. These State average figures were used in the life-cycle cost calculation results presented in Chapter 9, and they are recommended for use in future analyses until updated by the Connecticut Siting Council.

References:

1. Northeast Utilities System, Response to Connecticut Siting Council Request for Information for Docket No. LIFE-CYCLE 2011, Connecticut Siting Council Investigation into the Life-cycle Costs of Electric Transmission Lines, Interrogatory Set 2, CSC-012, October 21, 2011.
2. Northeast Utilities System, Response to Connecticut Siting Council Request for Information for Docket No. LIFE-CYCLE 2011, Connecticut Siting Council Investigation into the Life-cycle Costs of Electric Transmission Lines, Interrogatory Set 2, CSC-013, October 21, 2011.
3. United Illuminating, Response to Connecticut Siting Council Request for Information for Docket No. LIFE-CYCLE 2011, Connecticut Siting Council Investigation into the Life-cycle Costs of Electric Transmission Lines, Interrogatory Set 2, Q-CSC-012.
4. United Illuminating, Response to Connecticut Siting Council Request for Information for Docket No. LIFE-CYCLE 2011, Connecticut Siting Council Investigation into the Life-cycle Costs of Electric Transmission Lines, Interrogatory Set 2, Q-CSC-013.

5. Connecticut Siting Council, RE: Life-Cycle 2011, Investigation into the Life-Cycle Costs of Electric Transmission Lines, November 15, 2011, Hearing Transcript, page 61.

7. EMF Mitigation Costs

Electric and magnetic fields (EMFs) are invisible lines of electrical and magnetic force that surround any electrical conductor with a current flowing along its length. For EMF at 60 Hz the electric field and the magnetic field may be treated separately. Both types of fields are present in the immediate vicinity of most power transmission lines, and in general:

- The electric field level (measured in kilovolts/meter, kV/m) increases in direct proportion to line voltage.
- The magnetic field level (measured in milligauss, mG) increases in direct proportion to the current flow in the line.

The levels of the both the electric field and the magnetic field are much higher in close proximity to a transmission line than they are at some distance from the line.

Transmission line EMF has been discussed at some length over the last 40 years, because there is concern that these fields may present health risks to those who are exposed to them on a regular basis.

International health and safety agencies, including the World Health Organization (WHO), the International Agency for Research on Cancer (IARC), and the International Commission on Non-Ionizing Radiation Protection (ICNIRP), have studied the scientific evidence regarding possible health effects from MF produced by non-ionizing, low-frequency (60-Hz) alternating currents in transmission lines. Two of these agencies attempted to advise on quantitative guidelines for mG limits protective of health, but were able to do so only by extrapolation from research not directly related to health: by this method, the maximum exposure advised by the International Committee on Electromagnetic Safety (part of the Institute of Electrical and Electronic Engineers) was 9,040 mG, and the maximum exposure advised by the ICNIRP was 2,000 mG. (These maximum exposure guidelines are for the "general public.") Otherwise, no quantitative exposure standards based on demonstrated health effects have been set world-wide for 60-Hz MF, nor is there any such state or federal standards in the U.S.

The Council has examined this topic in depth and has issued "Electric and Magnetic Fields Best Management Practices for the Construction of Electric Transmission Lines in Connecticut" in December 2007. This document is attached to this report in Appendix G.

Because there often are costs associated with mitigating EMF, this chapter addresses the field levels associated with the types of lines anticipated for Connecticut and discusses the costs needed to reduce them. These field levels were not explicitly modeled for the exact line designs illustrated in Section 2. Instead, field profiles from other studies for similar line types and voltages are presented in this section to show the relative magnitudes of such fields, some alternatives for reducing the field levels, and the approximate cost of doing so.

In most cases, higher tower costs result from designs required for mitigation of EMF levels. CL&P and UI together constructed new 345 kV transmission lines between Scovill Rock Switching Station in Middletown and Norwalk substation, which required a split-phase line for 12.1 miles, taller structures in some areas, and a shift in ROW. The additional cost of these EMF mitigation measures was $30.8 million[1] .

7.1 Overhead Construction

Both electric and magnetic fields are present in the area surrounding any overhead AC transmission line. The levels of these fields vary with line voltage and current, line design, and distance from the three phase conductors. These effects are illustrated in this section for typical 345 kV and 115 kV lines. Background on the assumed line configurations is provided in Appendices A and G.

7.1.1 Effects of line configuration and voltage

The arrangements and spacing of conductors on an overhead line significantly influence the EMF levels under the line. For example, Table F-1 shows the magnetic and electric fields for both horizontal and delta conductor configurations at 345 kV. Magnetic fields for the delta configuration are 64 percent of those for the horizontal configuration directly under the line. However, delta configuration magnetic fields are approximately half of those for the horizontal configuration at distances of 20-100 ft. from the centerline. Maximum electric fields for the delta configuration are only 15 percent lower than those for the horizontal configuration, but they are 50 percent lower at distances from 40 to 100 feet from the centerline. These reduced magnetic and electric fields for lines with a delta configuration must be balanced against first costs, which are approximately 80 percent higher.

Line voltage also is an important factor in determining EMF levels near an overhead transmission line. Table F-2 shows various magnetic and electric field levels for both horizontal and delta conductor configurations at 115 kV. When compared with similar EMF levels in Table F-1 for 345 kV lines, the Table 8-2 data confirm that electric fields are impacted most by changes in line voltages. The line voltages in Table F-2 are approximately one-third of those for Table F-1, but the maximum electric fields are reduced by almost a factor of four. In this case, the reductions are due not only to changes in voltage but also to changes in conductor height and spacing. Because the assumed current flows for the 115 kV lines are 502 Amperes per phase, as was the case for the comparable 345 kV lines, magnetic field levels changed far less between Tables F-1 and F-2. Once again, the changes are primarily due to differences in conductor configuration and spacing.

7.1.2 Split-phasing

Split-phasing dramatically illustrates the effects of line configuration. It reduces EMF by multiplying the number of conductors for a given circuit and arranging them on the towers in such a way that their individual EMFs cancel each other out. The most typical 115 kV arrangements use two conductors per phase, for a total of six conductors, while split-phase 345 kV lines double that number, for a total of 12 conductors. In either case, the towers must be much taller and stronger than conventional ones to carry the added conductors, with associated additional visibility and substantial additional cost.

7.2 Underground construction

EMF from underground lines differs from EMF from overhead lines in two major respects:

1. Electric fields are zero above an underground line because the ground is at zero potential, and it is an excellent conductor of electricity.
2. Magnetic fields above an underground line can be higher than those beneath an overhead line because the conductors are much closer to the ground level, where most human contact would take place.

Because of the first consideration, only the magnetic field associated with underground lines need to be examined. This section discusses how these magnetic fields vary with cable configuration and examines methods for mitigating these fields. Background on the assumed line configurations is provided in Appendices A and G.

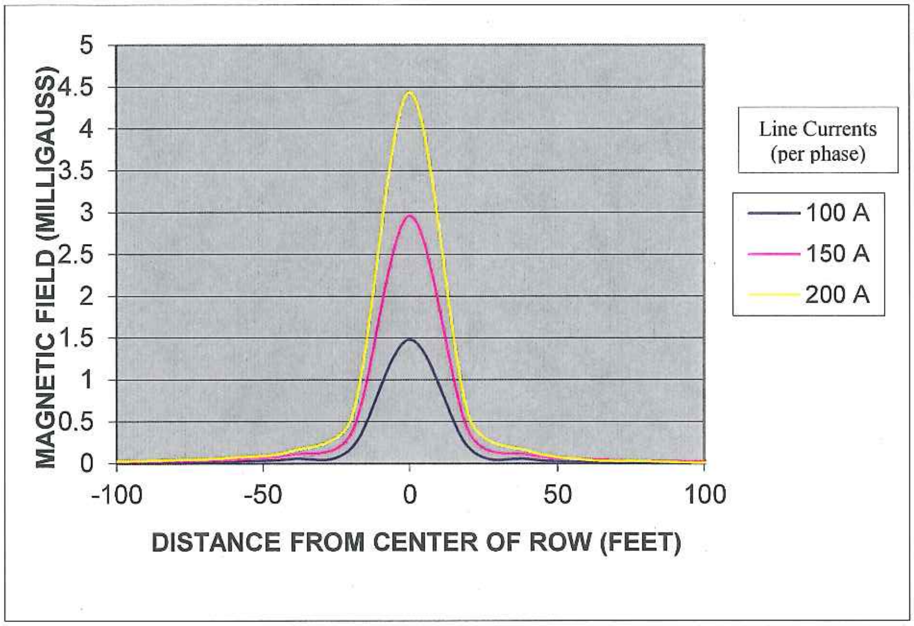
7.2.1 Effects of cable configuration

As is true with overhead transmission lines, the magnetic fields associated with underground lines vary considerably with the configuration of the cables for each of the three phases. Horizontal and delta configurations are both very common, and the magnetic fields for both are highest in the center of the ROW. As Appendix E, Figure E-1 shows, the maximum magnetic field for the assumed 115 kV XLPE line with cables in a horizontal configuration and a loading level of 502 Amperes per phase is approximately 200 mG, but it is less than 60 mG only 20 ft. from the center of the ROW. For a 115 kV XLPE line with similar cables in a delta configuration and similar loading, the maximum field is approximately 95 mG and the field is less than 25 mG only 20 ft. from the ROW centerline (See Appendix E, Figure E-2). Magnetic field levels for three different line loadings are presented in Appendix E, Figure E-1 and Figure E-2.

7.2.2 Effects of cable type

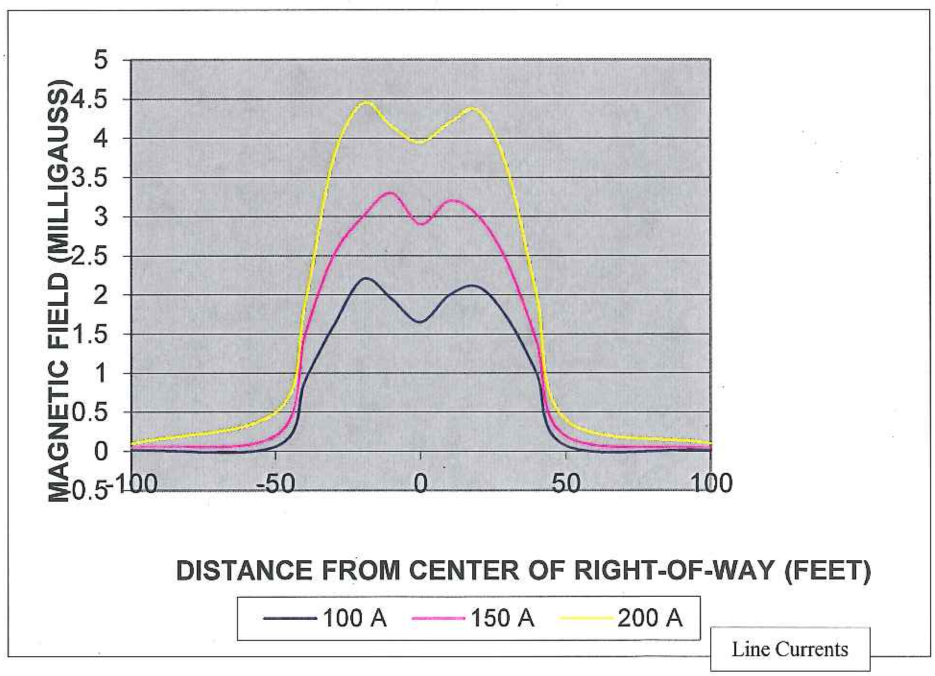
Magnetic fields are much lower for pipe-type underground lines, because the cables are compactly configured within a metal pipe. Also, a steel pipe provides a shielding effect on magnetic fields. Figure E- shows the theoretical magnetic field profile for a 345 kV HPFF cable. At an assumed loading level of 150 Amperes per phase, the maximum field intensity is only 3mG. Measurements recently taken on the 345 kV HPFF section of the Bethel-Norwalk Project[2] agree in general with the magnitudes shown in Appendix F, Figure E-3, but the magnetic field profile is lower at the center of the ROW and peaks about 20 feet from the center of the ROW. This average profile, based on field measurements of the 345 kV HPFF ROW[2], is shown in Figure 7-1.

Figure 7-1: Magnetic Field Profiles for Typical 345 kV HPFF Line



Source: Connecticut Siting Council and Acres International Corp. [1]

Figure 7-2: Average of Magnetic Field Measurements for 345 kV XLPE Line



Source: CL&P [2]

7.2.3 Mitigation alternatives

The most common method for mitigating the magnetic fields of solid dielectric cables is cable reconfiguration. One type of cable reconfiguration is the arrangement of cables in a delta configuration, as previously illustrated by the reduced fields in Figure 7-2 . However, cable reconfiguration can also reduce magnetic fields by cancellation among the three phases in a manner similar to the split-phasing of overhead transmission lines. In this case, it is common to use two cables per phase and to arrange one set of three cables with phase ordering A-B-C, while arranging the other set of three cables in a B-C-A phase order. The two sets of cables are configured in parallel, either horizontally or vertically. When configured as a double circuit line such alternate phasing schemes can reduce magnetic fields by up to 50 percent with little additional cost above that for a standard double circuit line. When used as an alternative to a three-cable, single-circuit line, however, there is a cost penalty because the total required length of cable is doubled. Also, the number and relative location of ground continuity conductors can be used as a mitigating method.

Another mitigation method for XLPE lines is the use of metallic shielding. Such shielding, which typically involves the insertion of steel plates between the cables and the ground level, has not been used previously in Connecticut. Shielding methods were considered during the Docket 272 proceedings, however. Specifically, the Docket 272 Findings of Fact conclude that steel plates installed over the top of a 345 kV cable trench could reduce magnetic fields directly over the trench by a factor of two to five. However, such steel plates also cause a "wing effect" to either side of the trench where the magnetic fields would increase somewhat. When the location of interest is a short distance away from the cable trench, therefore, such plates are generally not an effective tool for mitigating magnetic field levels. The costs of these metallic shields vary with cable size and trench (or duct) size. However, they would most likely be used only in certain sensitive areas where human exposure to the field was a concern.

References:

1. Connecticut Siting Council and Acres International Corp. "Life-cycle Cost Studies for Overhead and Underground Electric Transmission Lines."
2. Northeast Utilities System, Response to Connecticut Siting Council Request for Information for Docket No. LIFE-CYCLE 2011, Connecticut Siting Council Investigation into the Life-cycle Costs of Electric Transmission Lines, Interrogatory Set 2, Q-CSC-019, October 21, 2011. Attachment 1 – "Post-Construction Magnetic Field Measurements", and Attachment 2 – "Pipe-Type Cable Magnetic Fields."

8. Environmental Considerations and Costs

While electric power delivery enhances the lives of citizens in many ways, it also has impacts that can affect almost every aspect of their environment. This chapter identifies and discusses those impacts for all major environmental resources. Then it discusses, and where possible quantifies, the costs of mitigating key environmental impacts.

8.1 Environmental issues by resource type

Table 8-1 summarizes potential environmental impacts that transmission lines can have on a variety of resource categories.

Table 8-1: Environmental Factors for Transmission Line Siting and Operation

Environmental Resources	Potential Impact Issues for Transmission Lines
Water Resources	Erosion and sedimentation into water bodies. Loss of stream and wetland habitat and function. Alterations in localized groundwater flow due to blasting (e.g., individual wells). Adverse effects on water quality as a result of herbicide use. Adverse effects of access roads and/or facilities placed in or across water resources.
Biological Resources	Disturbance to or loss of habitat. Modifications to vegetative diversity. Effects on birds (collisions, electrocution, disruption of nesting by vegetation clearing). Effects of herbicides. Effects on rare, threatened, or endangered species or their habitat. Effects of stream bank and water quality modifications, as well as loss of riparian vegetation on fisheries.
Land Use and Recreation	Restrictions on use options for land Multiple use of ROW Impacts of unauthorized use (e.g., ATV use leading to erosion/sedimentation)
Topography, Geology, and Soils	Conditions affect engineering design of transmission facilities (e.g., structure footings, spans, practicality of undergrounding). Modifications to topography (and effect of topography on feasibility of transmission line installation). Amount of blasting required. Soil erosion and/or instability. Soil compaction.
Visual Resources	Intrusive effects of towers and/or maintained ROW and other aboveground facilities. Degree of visual contrast to viewers.

Environmental Resources	Potential Impact Issues for Transmission Lines*
Cultural Resources	Direct effects on buried cultural resource sites. Indirect effects on standing historic structures as a result of views of transmission facilities.
Air Quality and Noise	Fugitive dust during construction. Noise during construction and from transmission wires during operation (audible corona discharge (crackling), under certain weather conditions is unlikely to occur with 115-kV or lower voltage facilities)
Agricultural Resources	Impacts to productivity caused by soil mixing, compaction (as a result of equipment access through agricultural areas, trenching)

The Council cautions that the specific environmental impacts due to electric transmission are all very project-specific. For example, one project might have a short access drive through an already cleared area. Another access drive might be longer with significant tree clearing and/or wetland crossings required to reach the ROW. In addition, each project might employ different types and/or quantities of environmental impact mitigation methods.

The potential impacts listed for these resource categories are meant to be illustrative and are by no means exhaustive. Such impacts frequently conflict with one another and lead to tradeoffs. For example, in Virginia it was found that running an electric transmission line along the side of a long north-south ridge about halfway from the bottom to the top would be visually less noticeable from a distance. However, such siting was less desirable from a biological perspective because the hot, dry ROW would prevent certain forest amphibians from reaching higher elevations to reproduce. Another example of a tradeoff is that geology and soils almost always affect water resources, which also affect biological resources. An exhaustive discussion of each category is beyond the scope of this report, which is limited by its focus on costs.

Both State and Federal agencies oversee certain aspects of Connecticut's environment, as listed in Table 8-2. Of these, the Connecticut Siting Council has the broadest responsibilities, and must grant approval by issuing a Certificate of Environmental Compatibility and Public Need. The Connecticut DEEP has a key role in overseeing water quality via stormwater regulations; also, projects in either coastal zones or "tidally influenced areas" receive greater scrutiny. Impacts on cultural and historic resources are overseen by the State Historic Preservation Office (SHPO), which requires a finding of "no adverse effect." Finally, the Public Utilities Regulatory Authority (PURA) must approve the line construction methods and give final approval to energize.

Two Federal agencies also oversee some aspects of transmission line siting in the State of Connecticut. Of these, USACE has the greatest influence. Specifically, they require a Section 404 permit for all dredge-and-fill activities (including wetlands and watercourses) and requires a Section 10 permit for any work that impacts navigable waterways.

USACE reviews permit applications and determines compliance pursuant to the Clean Water Act and the Rivers and Harbors Act. The U.S. Fish and Wildlife Service, National Marine Fisheries Service, the U.S. Environmental Protection Agency, and Native American Tribes provide input to the USACE permitting process.

Table 8-1 lists the various environmental factors associated with transmission line siting and operation. Table 8-2 lists the various environmental permits and/or certifications for typical transmission line projects.

Table 8-2: Environmental Permit/Certificate Approvals for Typical Transmission Line

Agency	Type of Approval Required
State	
Connecticut Siting Council	Certificate of Environmental Compatibility and Public Need
Connecticut Department of Energy and Environmental Protection	401 Water Quality Certification Storm Water Pollution Prevention Approval for temporary disturbance of more than 5 acres of land Coastal Zone Consistency Certification of Structures and Dredging Permit for coastal zone or tidally influenced areas (from Office of Long Island Sound Programs) Stream Channel Encroachment Line Permit
State Historic Preservation Commission	Review of archaeological and historic resources, consistent with the National Historic Preservation Act; approval by finding of no adverse effect
Public Utilities Regulatory Authority	Method and Manner of Construction approval Approval to Energize
Federal	
U.S Army Corps of Engineers, New England Division	404 permit for dredge and fill activities (wetlands and watercourses) or *nationwide permit approval (*These are required for most utilities. Note that the nationwide permits have been replaced with Programmatic General Permits.) Section 10 permit for work in navigable waterway
Federal Aviation Administration	Notification of presence of overhead lines only

8.2 Effects on line cost

While transmission-line construction causes a wide range of environmental impacts, the cost effects of these impacts are usually attributable to one of the following causes:

- Larger tower structures and construction restrictions in affected areas;
- Design changes to prevent accidental release of fluid in underground HPFF cables;
- Re-routing to avoid sensitive areas;
- Toxic substance handling and disposal;
- Site restoration activities post-construction; and
- Delays in project start-up or completion.

These all usually result in increased first costs for engineering and materials. Each of these topics is discussed briefly, with some examples, in the remainder of this section.

8.2.1 Larger tower structures and construction restrictions

Power lines that traverse environmentally-sensitive areas, such as wetlands, river crossings, tidal areas, and forested areas where endangered or threatened species are found often must use higher, stronger poles/towers that permit longer spans and fewer foundations, minimizing vegetation loss and associated damage. However, as has been established in earlier sections, larger towers require larger and more elaborate foundations, and, overall, significantly increase costs.

Construction cost increases may also result from the use of specialized methods and/or from complex work scheduling. For example, options considered during siting proceedings for the Middletown-Norwalk 345 kV line called for the use of wooden mats during construction in wetland areas. Such mats permit as much as a five-fold reduction in the surface area that is disturbed during construction, but are expensive.

Work scheduling also can be greatly complicated by efforts to protect fish and wildlife. Construction for for the Middletown-Norwalk line, for instance, was held to the following conditions:

- --no in-stream work from June 1 to September 30;
- --no work in areas supporting wood turtles and box turtles outside of November 1 to April 1;
- --no in-water work in winter flounder spawning areas from February 1 to May 15;
- --no work threatening winter flounder anadromous migration from July 1 to September 30;
- --in cases where a jack-and-bore crossing technique creates a substantial amount of noise, time-of-day restrictions for work within the standard anadromous period from April 1 to June 30.

> "If a jack and bore crossing technique creates a substantial amount of noise, DEP may request a time-of-day restriction for work within the standard anadromous period from April 1 to June 30…"

8.2.2 Design Changes to prevent environmental contamination

Sometimes, transmission line design changes are needed to prevent environmental contamination. In 2008, for instance, the Long Island Cable Replacement Project replaced seven underwater fluid-filled cables with three solid dielectric cables to eliminate the potential for accidental release of fluid if the cables were to be damaged. The cost of removal and disposal of the fluid-filled cables was $4.6 million. The project required permits from DEEP, the New York Department of Environmental Conservation and Public Service Commission, and USACE. A monitoring plan was required that includes bi-annual photos of the ocean floor for 10 years, magnetic field surveys, inspections, and future mitigation for oyster beds. CL&P paid for 51 percent of all costs and the Long Island Power Authority (LIPA) paid the remainder.[1]

8.2.3 Re-routing to avoid sensitive areas

One of the most common approaches to dealing with environmentally sensitive areas, such as parks, wetlands, and cultural sites is to avoid them by routing the line around them or over some alternative route. At a minimum, such avoidance results in higher costs due to greater line length and more angles in the ROW. At a maximum, an entirely new route may have to be found. For instance, in the case of an important 765 kV transmission line from West Virginia to Virginia, the designation of a major river as "wild and scenic" by the EPA caused the entire line application to be withdrawn. Several years were required to develop a new, much longer route.

The application phase for the Middletown-Norwalk line provided numerous examples of the need to avoid environmentally sensitive areas. Where complete avoidance was impossible, routes were selected to minimize exposure.

Another example occurred during maintenance repair of transmission towers on the North Bridgeport 115 kV overhead line in 2009, when UI needed to build an access road in order to avoid wetlands. The total cost was $100,000.[2]

In the most heavily developed sections of Southwest Connecticut, marine routes for transmission lines seem to be an attractive option. However, the necessity to protect shellfish beds generally presents insurmountable obstacles. More broadly, the Coastal Zone Management Act scrutinizes shoreline development in the context of a "water-dependent" use. A project that does not require water-front access is encouraged to be developed inland. Typically, electric transmission infrastructure is land-based.

Historical and cultural sites also are numerous in southern Connecticut. Two examples that affected the Middletown-Norwalk line routing included a route change to avoid a town historic district and a river-crossing change to avoid a cemetery. An interesting aspect of these last re-routings is that they both involved <u>shortening</u> the total line length and thus brought cost benefits. But such cases are a small minority.

8.2.4 Contaminated substance handling and disposal

One might not expect that the construction of a new transmission line would incur high costs from the handling of contaminated substances. However, this was a major cost concern for the Middletown-Norwalk line, part of which went underground along local and state roads in Southwest Connecticut.

Since some of the roadway soils were contaminated, the (then) DEP did not allow the excavated soils to be re-used for closing underground trenches. They had to be stored according to special rules and disposed of at an approved facility. Clean soils had to be brought in to complete construction. Furthermore, since the overhead part of the line crossed over the Middletown-Durham and Wallingford landfills, DEP required special permits from its Bureau of Waste Management for any pole structures within the footprints of those locations. Finally, at a new substation that was built for the line the soil was suspected to be contaminated by trichloroethylene (TCE) from a WW II business formerly upgrade of the site. Testing for TCE was required, and subsequently the same special measures taken with those soils as were taken with the contaminated roadway soils. In the end, the total cost for soil sampling, testing, and disposal on this project was $2.9 million for CL&P[1] and $14.6 million for UI.[2]

In a more recent transmission-line project, CL&P constructed a new 8.7-mile underground 115 kV cable system from Glenbrook Substation to Norwalk Substation, again using roadways. The same general type of soil testing, analysis, removal and disposal applied. In that case, the total cost was $2.5 million.[1]

8.2.5 Site restoration post-construction

Site restoration costs may be incurred in some locations. Because much of Connecticut is rocky with granite ledge that requires blasting, the need to engage in at least some site restoration is virtually assured. Typical examples of costly restoration include agricultural sites and areas with soils prone to erosion on steep grades, where re-grading and large-scale planting of vegetation is necessary.

In Connecticut, site restoration often involves wetland enhancements. Such was the case for the Middletown-Norwalk line. The project required permits from USACE and the (then) DEP, which were conditioned on the creation of a 2.2-acre wetland at Eisenhower Park in Milford, CT as well as a conservation easement on 74 acres of CL&P property in Middletown, CT. The total cost of constructing the wetland, including engineering and legal costs, was $2.2 million.[1]

8.2.6 Delays in project completion

Environmental reviews, discovery, and investigations may lead to necessary but substantial delays in line construction and commissioning. During delays, costs for both material and labor typically escalate, causing substantial increases in a line's first costs, which are the largest component of its life-cycle cost.
References:

1. Northeast Utilities System, Response to Connecticut Siting Council Request for Information for Docket No. LIFE-CYCLE 2011, Connecticut Siting Council Investigation into the Life-cycle Costs of Electric Transmission Lines, OCC-010, October 21, 2011.
2. United Illuminating, Response to Connecticut Siting Council Request for Information for Docket No. LIFE-CYCLE 2011, Connecticut Siting Council Investigation into the Life-cycle Costs of Electric Transmission Lines, Interrogatory Set 1, CSC-011.

9. Life-Cycle Cost Calculations for Reference Lines

As outlined in Section 1 of this report, life-cycle costs are the total costs of ownership of an asset over its useful life. In the case of electric transmission lines, the useful life of the asset can be a subject of much study and debate. As was exhibited in Section 1, however, the useful life period used in a NPV life-cycle cost calculation is less important as an absolute term than as a comparison of assets over an equivalent period of service.

For the purpose of life-cycle costs calculations for this study, a period of forty years has been used. This 40-year life is judged to be a fair representation of a life-cycle analysis period for transmission lines and is consistent with those employed throughout the utility industry.

This chapter offers information on the results of life-cycle cost calculations for the eight transmission line designs that were identified in Section 2. These eight line designs are the ones that are in use, or will be used, in Connecticut for the foreseeable future. Also included in this chapter are an analysis of the life-cycle cost results, the contribution of the major components to the life-cycle costs and a discussion of the primary drivers of the costs.

9.1 Life-cycle Cost Assumptions

The input data used in performing the calculations for life-cycle costs for overhead and underground transmission line designs include first costs, operating and maintenance costs, and the cost of electrical losses.

The economic calculation variables used in this report include:

Capital recovery factor:	14.1 percent[1]
Operation and maintenance cost escalation:	4.0 percent[2]
Load growth:	2.03 percent[3]
Energy cost escalation	1.2 percent[4]
Discount rate:	8.0 percent[5]

These factors are consistent with the previous life-cycle cost studies done for the Connecticut Siting Council and are representative of variables used by utilities in their cost calculations. More details on each variable are provided below.

Capital recovery factor (fixed charge rate): This factor represents the levelized annual cost of the fixed costs of ownership in terms of percentage of the first cost. This includes the following components:

1. return on the capital investment required for construction
2. depreciation
3. federal and State income tax
4. property taxes
5. insurance

This does not include O&M because this is typically considered as variable with respect to the first cost of the facility. A value of 14.1 percent was provided by CL&P and is typical for Connecticut utilities.

O&M cost escalation: The cost escalation factor is used to account for the ongoing increases in the cost of materials and labor over the life of the asset. A factor of 4 percent, inclusive of economic inflation, has been used in this study and is consistent with the cost escalation factors used by the Connecticut utilities.

Load growth: The cost of electrical energy losses are the second most significant component in a transmission line life-cycle cost study. The losses experienced on a line are a factor of the line loading. Therefore, increases in load have a direct impact on both losses and the associated costs. In Connecticut, an average load growth estimate of 2.03 percent has been adopted as part of the 2011 Connecticut Siting Council Ten Year Load Forecast and was confirmed by the utilities as a reasonable estimate for the purpose of this study.

Energy cost escalation: The primary variable in the calculation of the cost of electrical losses is the cost of energy produced by the electricity generator. The cost of energy is directly tied to the cost of fuel and as such, can be highly variable, depending upon energy markets worldwide. For this study an energy escalation factor of 1.2 percent per year has been assumed based on data from the 2012 Integrated Resource Plan (IRP)[4].

Discount rate: An interest rate of 8 percent was used to discount the cash flows over the 40-year life-cycle cost period to their present values.

Using the factors outlined here, a forty-year NPV analysis of the costs of transmission lines was performed. The costs and cash flows used in this study are based on the current costs incurred by the Connecticut utilities for transmission line projects, operations and maintenance expenses, and electrical line losses. As stated previously, however, the life-cycle cost of a transmission line is specific to the particular project being evaluated. The high variability of costs for permitting, materials, land and other components can significantly alter the life-cycle cost from one project to another.

This study has used recent cost information, as reported by the utilities to FERC, as the basis for the life-cycle cost analyses. After extensive discussion with utility representatives, assumptions have been made that are believed to be fair and representative of current conditions in the State.

The forty-year life-cycle cost calculations for the twelve transmission line designs presented in this report are found in Appendix B. The remainder of this chapter will be used to highlight comparisons and present some analysis of these calculations.

9.2 Life-cycle Costs for Alternative Line Types

The cumulative NPV of life-cycle costs is the value used to compare design alternatives for the purpose of capital investment decisions. As highlighted earlier in this report, the first cost component of both overhead and underground lines is the primary contributor to the life-cycle cost and can represent differences in costs by factors as high as four to six times. Within a specific overhead or underground design, however, there are also differences that can vary the cost of a line significantly.

Table 9-1 shows the NPV of total life-cycle costs for each of the overhead lines considered in this report.

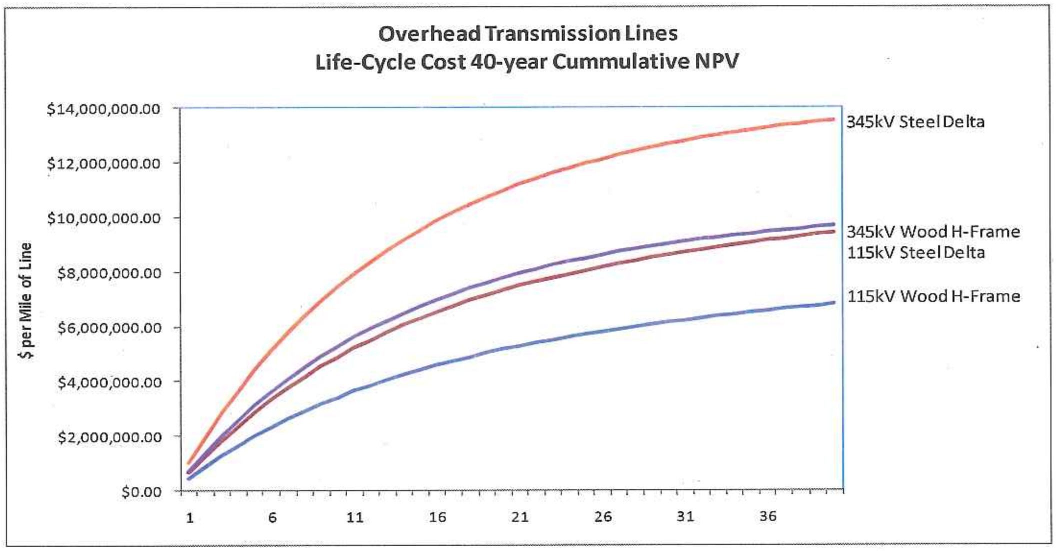
Table 9-1: NPV of Overhead Transmission Line Life-Cycle Cost Components

LCC Component	115kV Wood H-Frame	115kV Steel Delta	345 kV H-Frame	345kV Steel Delta
Poles & Foundations	$1,034,631	$2,450,297	$2,280,275	$4,739,447
Conductor & Hardware	$1,307,434	$1,410,458	$2,476,827	$3,043,953
Site Work	$1,616,554	$2,483,186	$2,435,045	$2,850,427
Construction	$227,826	$229,568	$228,919	$247,750
Engineering	$334,465	$818,996	$455,752	$648,572
Sales Tax	$118,215	$188,155	$229,357	$369,433
Admin/PM	$935,291	$609,297	$1,008,872	$1,071,855
Losses	$263,512	$263,512	$107,002	$107,002
O&M Costs	$96,631	$96,631	$96,631	$96,631
Total LCC	$5,934,557	$8,550,098	$9,318,679	$13,175,069

Note: all costs are in $ per circuit-mile.

Figure 9-1 shows the cumulative NPV of life-cycle costs over the 40-year life for each of the overhead line designs discussed in this report.

Figure 9-1: Overhead Transmission Line Life-Cycle Costs



Note: costs are in $ per circuit-mile.

Table 9-2 shows the NPV of total life-cycle costs for each of the underground lines considered in this report.

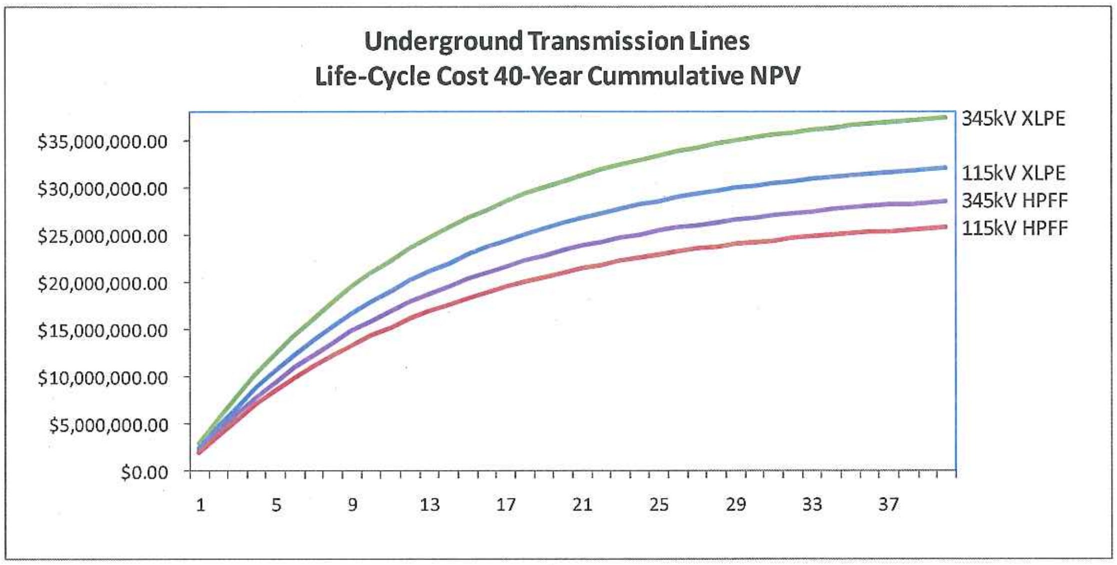
Table 9-2: NPV of Underground Transmission Line Life-Cycle Cost Components

LCC Component	115kV XLPE	115kV HPFF	345kV XLPE	345kV HPFF
Ducts & Vaults	$10,104,687	$8,935,795	$11,821,084	$9,928,661
Cable & Hardware	$11,052,001	$7,677,232	$12,929,310	$8,530,258
Site Work	$5,052,343	$4,530,826	$5,910,542	$5,034,250
Construction	$631,543	$503,426	$738,818	$559,362
Engineering	$789,429	$629,281	$1,108,227	$839,042
Sales Tax	$1,002,259	$787,357	$1,172,504	$874,841
Admin/PM	$2,944,885	$2,107,338	$3,260,403	$2,201,647
Losses	$81,062	$95,883	$81,062	$95,883
O&M Costs	$177,000	$177,000	$177,000	$177,000
Total LCC	$31,835,212	$25,444,137	$37,198,951	$28,240,945

Note: all costs are in $ per circuit-mile.

Figure 9-2 shows the yearly growth in cumulative NPV of life-cycle costs over the 40-year life for each of the underground lines considered.

Figure 9-2: Underground Transmission Line Life-Cycle Costs



Note: costs are in $ per circuit-mile.

This information shows the degree to which first costs dominate the life-cycle costs of transmission lines, particularly underground lines. The O&M cost component of every line type made up only 1 percent of the NPV of the life-cycle cost total. The cost of electrical energy losses made up approximately 4 percent of the NPV of the life-cycle cost total for each of the four underground line types.

9.3 Observations and Comparison of Life-cycle Costs

Table 9-3 provides a summary of life-cycle costs and ranking for each of the eight (8) line types presented in this report.

Table 9-3: Total NPV and Ranking of Transmission Life-Cycle Costs

Line Type	Total NPV of life-cycle costs
Overhead 115 kV Wood H-Frame	$5,934,557
Overhead 115 kV Steel Delta	$8,550,098
Overhead 345 kV H-Frame	$9,318,679
Overhead 345 kV Steel Delta	$13,175,069
Underground 115 kV HPFF	$25,444,137
Underground 345 kV HPFF	$28,240,945
Underground 115 kV XLPE	$31,835,212
Underground 345 kV XLPE	$37,198,951

Note: costs are in $ per circuit-mile over a 40-year life.

From this life-cycle cost comparison, one can make the following general observations about the cost of transmission lines in the State of Connecticut:

1. The total life-cycle cost of steel delta 115 kV overhead lines is roughly 44 percent higher than wood H-frame lines. One of the major reasons is the cost of materials. Similarly, the total life-cycle cost of steel delta 345 kV overhead lines is roughly 41 percent higher than H-frame lines.
2. The total life-cycle cost of overhead 345 kV lines is approximately 54 to 57 percent higher than overhead 115 kV lines, while providing 3 times the capacity for an equivalent conductor size.
3. The total life-cycle cost of underground XLPE cables is 25 to 32 percent higher than for HPFF cable systems. Since HPFF (fluid-filled cable) is the environmentally undesirable choice near waterways, this cable is also not being used as much as in the past.
4. The total life-cycle cost of underground 345 kV cables is roughly 11 to 17 percent higher than underground 115 kV cables, while providing 3 times the capacity for an equivalent conductor size.
5. The total life-cycle cost of underground lines is roughly two to five times higher (mirroring first costs) than the cost of overhead lines at the same voltage level.

References:

1. A Capital Recovery Factor of 14.1 percent was used in this analysis, which is the rate provided by CL&P during 2011 testimony. This figure is typical for utilities in the United States.
2. O&M cost escalation factor of 4.0 percent and Energy cost escalation factor of 5.0 percent were used in this analysis to be consistent with the values used in the 2007 Life-cycle Cost Report.
3. Annual load growth rate of 2.03 percent was used in these calculations based on the Council's 10-Year Forecast of Electric Loads and Resources (see References in Section 1).
4. Page 21 (Figure 9) of the 2012 IRP has base case energy prices for 2015 through 2022. The compound annual growth rate over the time period is 1.17 percent (or approximately 1.2 percent). The Council used this 1.2 percent figure for energy cost escalation.
5. A Discount Rate of 8.0 percent was used in these calculations and was reduced from 10.0 percent in the 2007 Life-cycle Cost Report.

Conclusion

Every five years per Connecticut General Statutes § 16-50r, the Council issues a report regarding the life-cycle costs of transmission lines in the State of Connecticut. This report aids the utilities, public officials, and the public in comparing the estimated costs of different electric transmission configurations. The life-cycle costs of electric transmission lines include costs that are incurred to permit and build a line, operate the line with resulting electrical energy loses, and maintain the line over its useful life. These costs are projected over a 40-year life, and the net present value is calculated to convert all of these costs (that are incurred on various years) to a single equivalent cost at the beginning of that time period.

Both 115 kV and 345 kV (single-circuit) overhead and underground transmission line configurations were considered because they are the most common transmission line configurations in Connecticut. New 69-kV lines are not expected in Connecticut due to their limited capacity. New double-circuit lines are not expected due to reliability concerns associated with two circuits sharing common transmission structures. As such, both 69-kV lines and double-circuit lines were not considered in this life-cycle cost analysis.

For overhead lines, the cost of materials is a significant component of the life-cycle costs. For example, the total life-cycle cost of 115 kV steel delta overhead lines is roughly 44 percent higher than H-Frame lines. Similarly, the total life-cycle cost of steel delta 345 kV overhead lines is roughly 41 percent higher than H-frame lines. The total life-cycle cost of overhead 345 kV lines is approximately 54 to 57 higher than overhead 115 kV lines, while providing three times the capacity for an equivalent conductor size (or six times assuming that 345 kV lines have two conductors per phase). However, 345 kV lines require taller, stronger structures, larger foundations, and typically twice as many conductors as 115 kV lines. This results in significantly higher material costs.

Vegetation maintenance is another significant cost factor for overhead lines. These costs have increased since 2007 due to NERC reliability requirements. Other maintenance activities for overhead lines include climbing inspections, foot patrols, and infrared inspections to identify hot spots on splices and conductors.

Underground lines also require maintenance inspections, cleaning of ducts, manholes, etc., and moving or repairing boxes and potheads. Underground maintenance costs have been unsteady during the last five years, with major increases in 2007 and 2010. Predicting the future maintenance costs has proven to be challenging for underground lines.

For underground lines, the total life-cycle cost of XLPE (solid dielectric cable) is 25 to 32 percent higher than for HPFF (fluid-filled cable) systems in part due to larger splice vaults, material cost escalation, and other factors. With regard to a cost comparison by line voltage, the total life-cycle cost of underground

345 kV cables is roughly 11 to 17 percent higher than underground 115 kV cables, while providing three times the capacity for an equivalent conductor size (or six times with two conductors per phase).

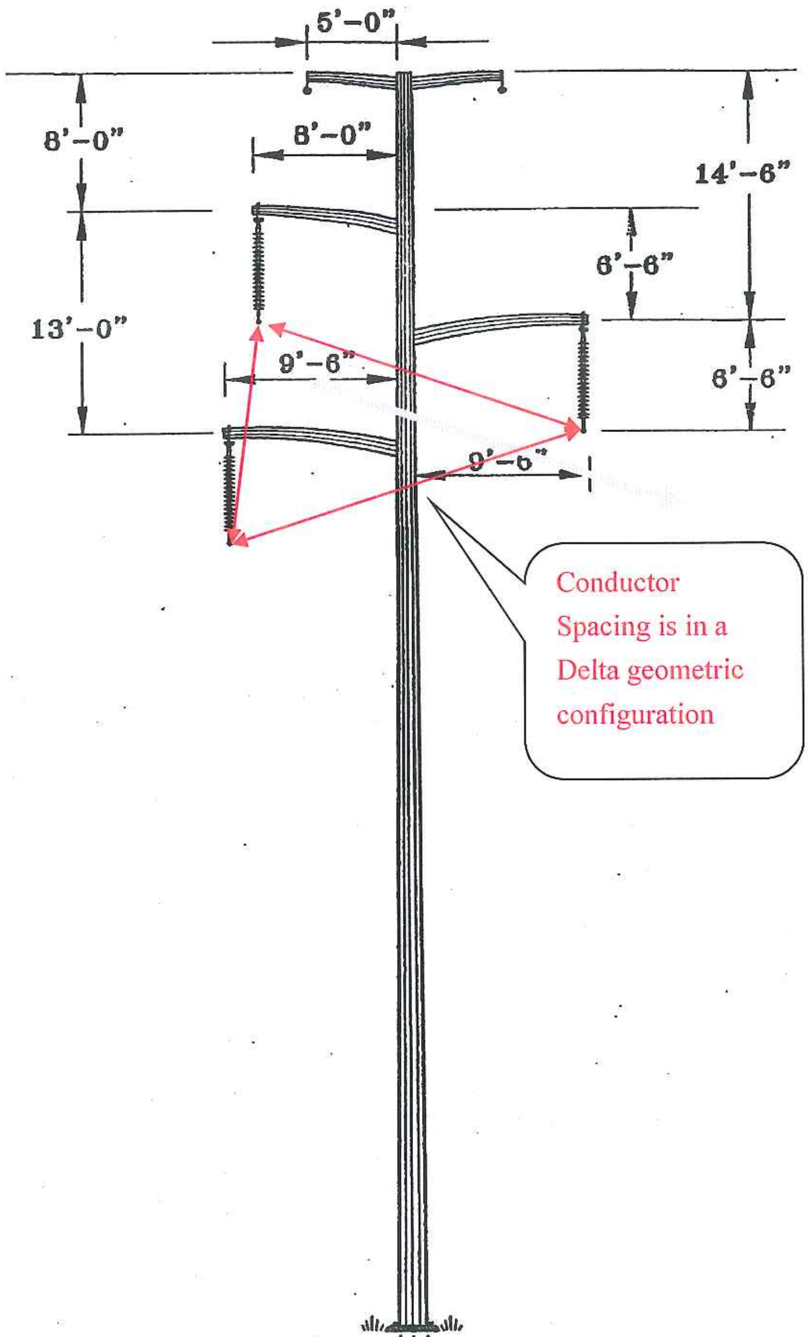
Overall, the total life-cycle cost of underground lines is roughly two to five times higher than the cost of overhead lines at the same voltage level. However, the decision to use underground versus overhead transmission is a complex one with cost being just one consideration.

This report is based on data specific to Connecticut. Caution should be applied when using this report for transmission lines outside of Connecticut.

A. Appendices

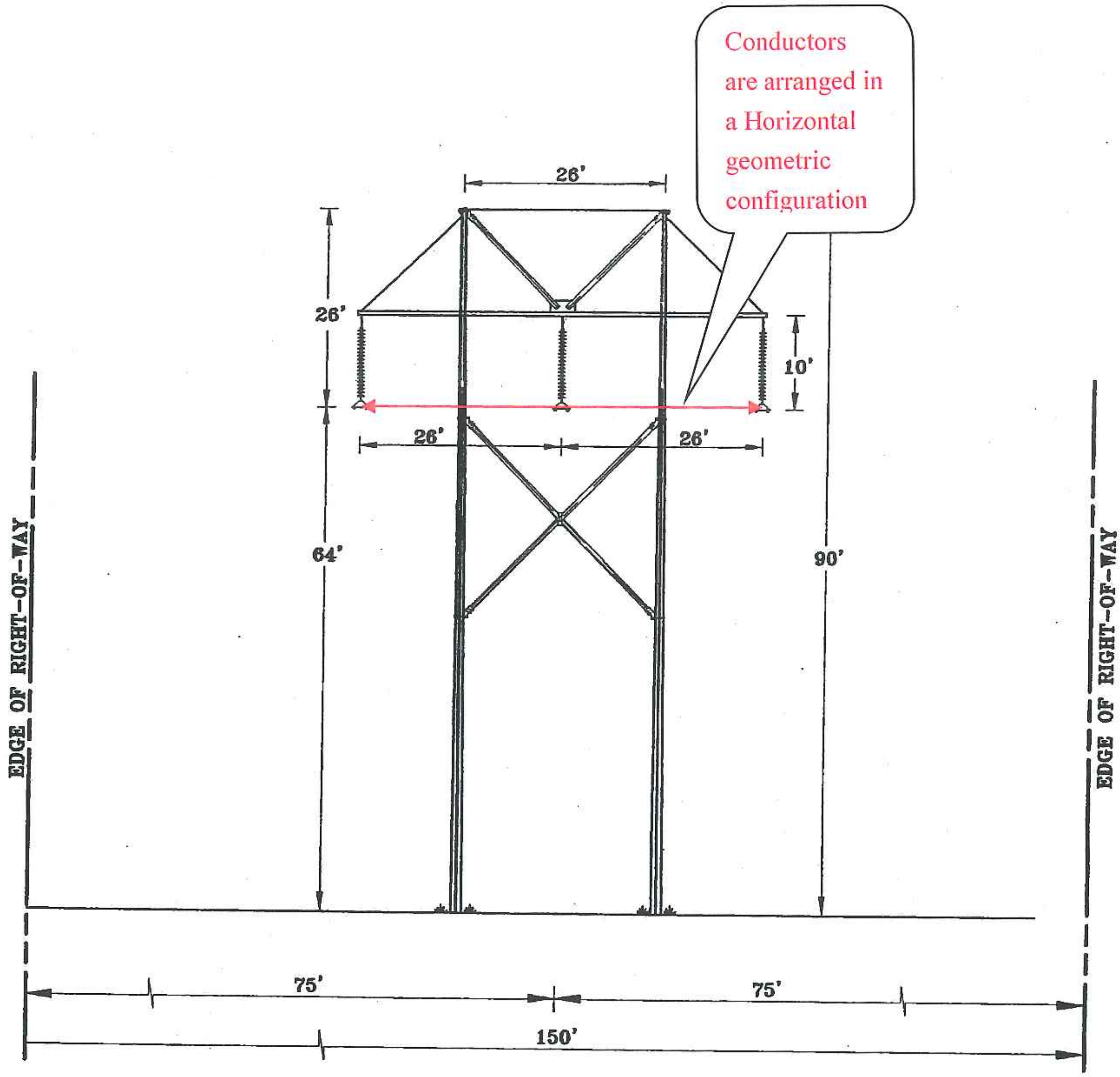
B. Line Configuration Drawings

B.1 Typical 115 kV Overhead Steel Pole with Single-circuit Delta Configuration



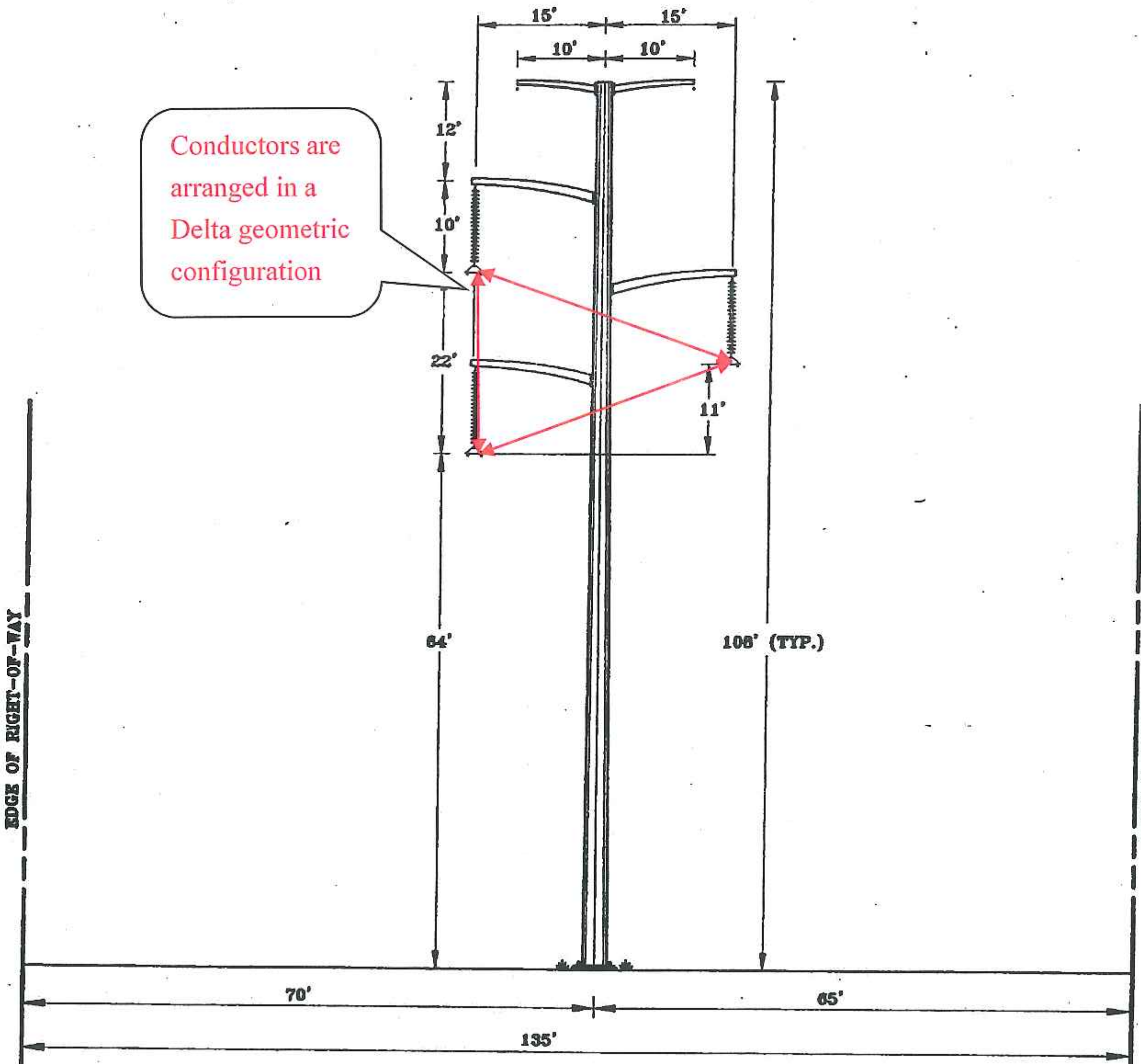
(Source: CL&P)

B.2 Typical 345 kV Overhead H-Frame Configuration



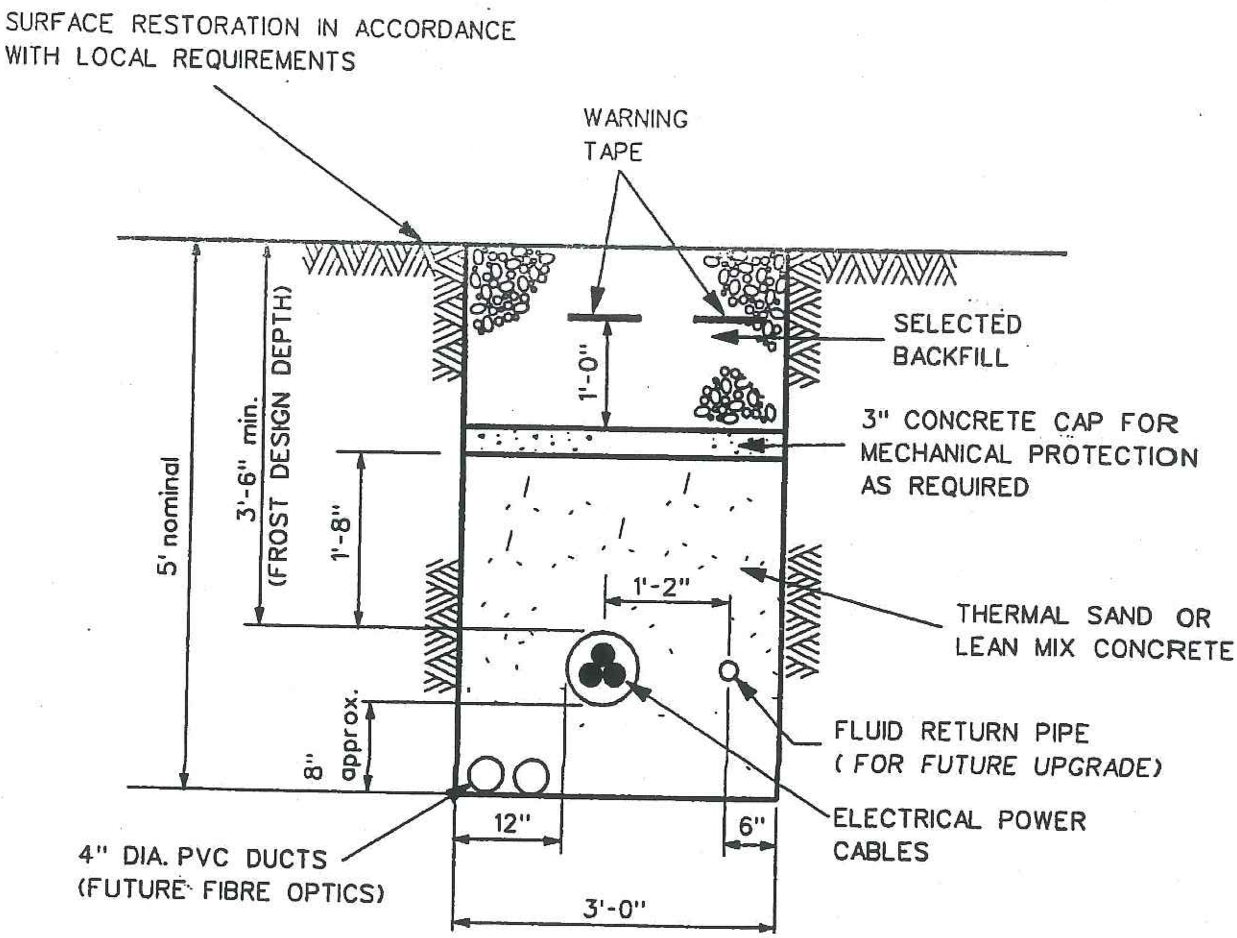
(Source: CL&P)

B.3 Typical 345 kV Overhead Steel Pole with Single-circuit Delta Configuration



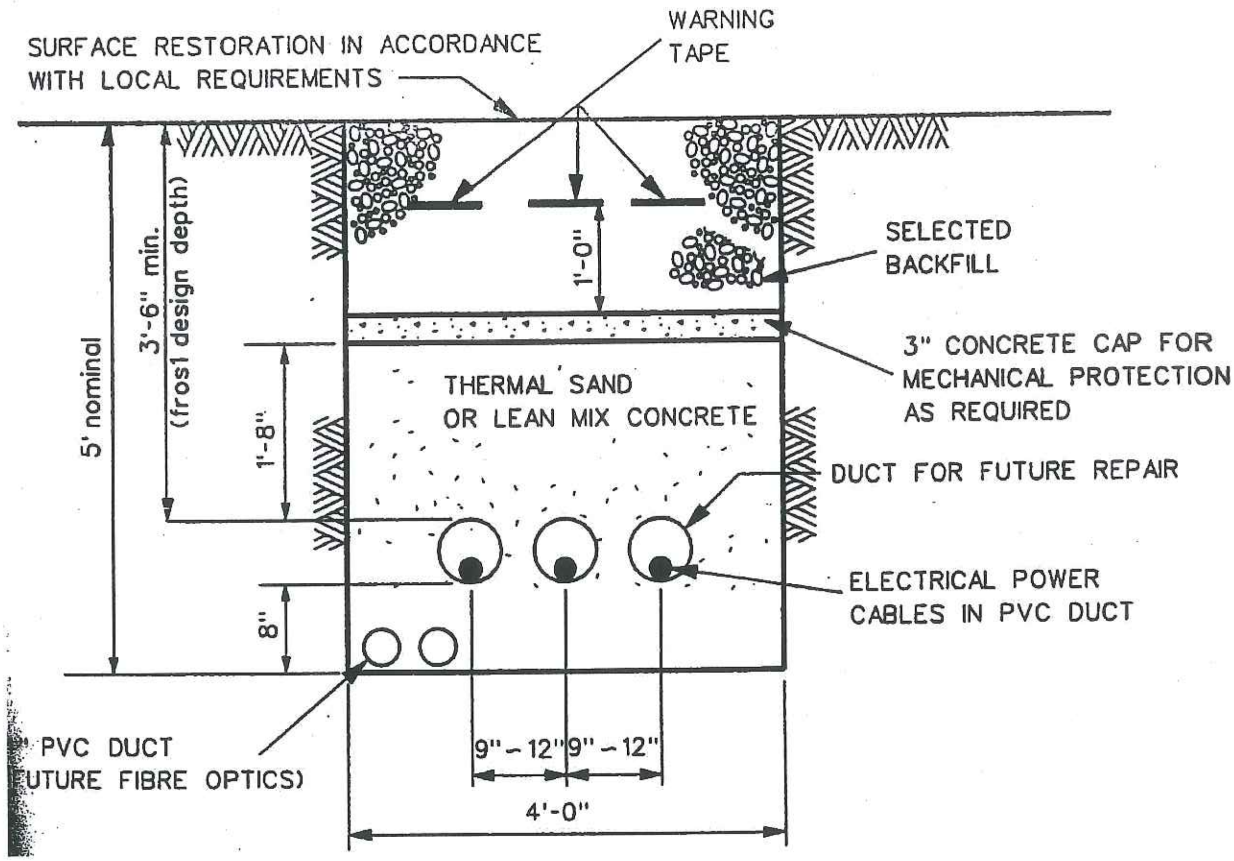
(Source: CL&P)

B.4 Typical 115 kV Underground HPFF Single-circuit Cable Installation



(Source: CL&P)

B.5 Typical 115 kV Underground XLPE Single-circuit Cable Installation



(Source: CL&P)

C. Life-Cycle Cost Tables

Overhead 115 kV Wood H-Frame

First Costs		Losses		
Poles & Foundations	$615,350.00	Conductor		1272 ACSS
Conductor & Hardware	$777,600.00	Resistance	0.0871	ohms/mi
Site Work	$961,450.00	Peak Line Current		502 amps
Construction	$135,500.00	Load Growth		2.03 percent
Engineering	$198,924.00	Loss Factor		0.38
Sales Tax	$70,309.00	Energy Cost		48 mils/kWh
Project Management	$556,267.00	Energy Cost Escalation		1.2 percent

Year	PV Factor	First Costs	Losses	O&M	PV Cost	Cumulative PV
1	0.93	$432,844	$10,266	$4,594	$447,704	$447,704
2	0.86	$400,781	$10,014	$4,424	$415,219	$862,923
3	0.79	$371,094	$9,768	$4,260	$385,122	$1,248,045
4	0.74	$343,605	$9,529	$4,102	$357,236	$1,605,280
5	0.68	$318,153	$9,295	$3,951	$331,399	$1,936,679
6	0.63	$294,586	$9,067	$3,804	$307,457	$2,244,136
7	0.58	$272,765	$8,844	$3,663	$285,272	$2,529,408
8	0.54	$252,560	$8,627	$3,528	$264,715	$2,794,123
9	0.50	$233,852	$8,416	$3,397	$245,665	$3,039,788
10	0.46	$216,530	$8,209	$3,271	$228,010	$3,267,798
11	0.43	$200,490	$8,008	$3,150	$211,648	$3,479,446
12	0.40	$185,639	$7,811	$3,033	$196,483	$3,675,929
13	0.37	$171,888	$7,620	$2,921	$182,429	$3,858,358
14	0.34	$159,156	$7,433	$2,813	$169,402	$4,027,760
15	0.32	$147,366	$7,250	$2,709	$157,325	$4,185,085
16	0.29	$136,450	$7,073	$2,608	$146,131	$4,331,216
17	0.27	$126,343	$6,899	$2,512	$135,754	$4,466,970
18	0.25	$116,984	$6,730	$2,419	$126,133	$4,593,103
19	0.23	$108,319	$6,565	$2,329	$117,213	$4,710,315
20	0.21	$100,295	$6,404	$2,243	$108,942	$4,819,257
21	0.20	$92,866	$6,247	$2,160	$101,273	$4,920,529
22	0.18	$85,987	$6,093	$2,080	$94,160	$5,014,690
23	0.17	$79,618	$5,944	$2,003	$87,565	$5,102,255
24	0.16	$73,720	$5,798	$1,929	$81,447	$5,183,701
25	0.15	$68,259	$5,656	$1,857	$75,772	$5,259,473
26	0.14	$63,203	$5,517	$1,788	$70,508	$5,329,981
27	0.13	$58,521	$5,382	$1,722	$65,625	$5,395,606
28	0.12	$54,186	$5,250	$1,658	$61,094	$5,456,699
29	0.11	$50,173	$5,121	$1,597	$56,891	$5,513,590
30	0.10	$46,456	$4,995	$1,538	$52,989	$5,566,579
31	0.09	$43,015	$4,873	$1,481	$49,369	$5,615,948
32	0.09	$39,829	$4,753	$1,426	$46,008	$5,661,956
33	0.08	$36,878	$4,636	$1,373	$42,887	$5,704,844
34	0.07	$34,147	$4,523	$1,322	$39,992	$5,744,835
35	0.07	$31,617	$4,412	$1,273	$37,302	$5,782,137
36	0.06	$29,275	$4,304	$1,226	$34,805	$5,816,942
37	0.06	$27,107	$4,198	$1,181	$32,486	$5,849,428
38	0.05	$25,099	$4,095	$1,137	$30,331	$5,879,759
39	0.05	$23,240	$3,995	$1,095	$28,330	$5,908,088
40	0.05	$21,518	$3,897	$1,054	$26,469	$5,934,557

Overhead 115 kV Steel Delta

First Costs		Losses		
Poles & Foundations	$1,457,321.00	Conductor		1272 ACSS
Conductor & Hardware	$838,874.00	Resistance	0.0871	ohms/mi
Site Work	$1,476,882.00	Peak Line Current		502 amps
Construction	$136,536.00	Load Growth		2.03 percent
Engineering	$487,100.00	Loss Factor		0.38
Sales Tax	$111,906.00	Energy Cost		48 mils/kWh
Project Management	$362,381.00	Energy Cost Escalation		1.2 percent

Year	PV Factor	First Costs	Losses	O&M	PV Cost	Cumulative PV
1	0.93	$635,936	$10,266	$4,594	$650,796	$650,796
2	0.86	$588,830	$10,014	$4,424	$603,268	$1,254,064
3	0.79	$545,213	$9,768	$4,260	$559,241	$1,813,305
4	0.74	$504,827	$9,529	$4,102	$518,458	$2,331,762
5	0.68	$467,432	$9,295	$3,951	$480,678	$2,812,440
6	0.63	$432,807	$9,067	$3,804	$445,678	$3,258,118
7	0.58	$400,748	$8,844	$3,663	$413,255	$3,671,373
8	0.54	$371,063	$8,627	$3,528	$383,218	$4,054,591
9	0.50	$343,576	$8,416	$3,397	$355,389	$4,409,980
10	0.46	$318,126	$8,209	$3,271	$329,606	$4,739,586
11	0.43	$294,561	$8,008	$3,150	$305,719	$5,045,305
12	0.40	$272,742	$7,811	$3,033	$283,586	$5,328,891
13	0.37	$252,539	$7,620	$2,921	$263,080	$5,591,971
14	0.34	$233,832	$7,433	$2,813	$244,078	$5,836,049
15	0.32	$216,511	$7,250	$2,709	$226,470	$6,062,519
16	0.29	$200,474	$7,073	$2,608	$210,155	$6,272,674
17	0.27	$185,624	$6,899	$2,512	$195,035	$6,467,709
18	0.25	$171,874	$6,730	$2,419	$181,023	$6,648,732
19	0.23	$159,142	$6,565	$2,329	$168,036	$6,816,767
20	0.21	$147,354	$6,404	$2,243	$156,001	$6,972,768
21	0.20	$136,439	$6,247	$2,160	$144,846	$7,117,613
22	0.18	$126,332	$6,093	$2,080	$134,505	$7,252,119
23	0.17	$116,974	$5,944	$2,003	$124,921	$7,377,040
24	0.16	$108,310	$5,798	$1,929	$116,037	$7,493,076
25	0.15	$100,287	$5,656	$1,857	$107,800	$7,600,876
26	0.14	$92,858	$5,517	$1,788	$100,163	$7,701,039
27	0.13	$85,980	$5,382	$1,722	$93,084	$7,794,123
28	0.12	$79,611	$5,250	$1,658	$86,519	$7,880,641
29	0.11	$73,714	$5,121	$1,597	$80,432	$7,961,073
30	0.10	$68,253	$4,995	$1,538	$74,786	$8,035,859
31	0.09	$63,198	$4,873	$1,481	$69,552	$8,105,411
32	0.09	$58,516	$4,753	$1,426	$64,695	$8,170,106
33	0.08	$54,182	$4,636	$1,373	$60,191	$8,230,298
34	0.07	$50,168	$4,523	$1,322	$56,013	$8,286,310
35	0.07	$46,452	$4,412	$1,273	$52,137	$8,338,447
36	0.06	$43,011	$4,304	$1,226	$48,541	$8,386,988
37	0.06	$39,825	$4,198	$1,181	$45,204	$8,432,192
38	0.05	$36,875	$4,095	$1,137	$42,107	$8,474,299
39	0.05	$34,144	$3,995	$1,095	$39,234	$8,513,532
40	0.05	$31,615	$3,897	$1,054	$36,566	$8,550,098

Overhead 345 kV H-Frame

First Costs		Losses		
Poles & Foundations	$1,356,200	Conductor	(bundled)	1590 ACSS
Conductor & Hardware	$1,473,100	Resistance	0.0354	ohms/mi
Site Work	$1,448,250	Peak Line Current		502 amps
Construction	$136,150	Load Growth		2.03 percent
Engineering	$271,060	Loss Factor		0.38
Sales Tax	$136,411	Energy Cost		48 mils/kWh
Project Management	$600,029	Energy Cost Escalation		1.2 percent

Year	PV Factor	First Costs	Losses	O&M	PV Cost	Cumulative PV
1	0.93	$707,768	$4,168	$4,594	$716,530	$716,530
2	0.86	$655,341	$4,066	$4,424	$663,831	$1,380,362
3	0.79	$606,797	$3,966	$4,260	$615,023	$1,995,385
4	0.74	$561,849	$3,869	$4,102	$569,820	$2,565,205
5	0.68	$520,230	$3,774	$3,951	$527,955	$3,093,161
6	0.63	$481,695	$3,682	$3,804	$489,181	$3,582,341
7	0.58	$446,014	$3,591	$3,663	$453,268	$4,035,610
8	0.54	$412,976	$3,503	$3,528	$420,007	$4,455,617
9	0.50	$382,385	$3,417	$3,397	$389,199	$4,844,816
10	0.46	$354,060	$3,333	$3,271	$360,664	$5,205,480
11	0.43	$327,833	$3,252	$3,150	$334,235	$5,539,715
12	0.40	$303,549	$3,172	$3,033	$309,754	$5,849,469
13	0.37	$281,064	$3,094	$2,921	$287,079	$6,136,548
14	0.34	$260,245	$3,018	$2,813	$266,076	$6,402,624
15	0.32	$240,967	$2,944	$2,709	$246,620	$6,649,244
16	0.29	$223,118	$2,872	$2,608	$228,598	$6,877,842
17	0.27	$206,591	$2,801	$2,512	$211,904	$7,089,747
18	0.25	$191,288	$2,733	$2,419	$196,440	$7,286,186
19	0.23	$177,118	$2,666	$2,329	$182,113	$7,468,299
20	0.21	$163,998	$2,600	$2,243	$168,841	$7,637,140
21	0.20	$151,850	$2,536	$2,160	$156,546	$7,793,687
22	0.18	$140,602	$2,474	$2,080	$145,156	$7,938,843
23	0.17	$130,187	$2,414	$2,003	$134,604	$8,073,446
24	0.16	$120,544	$2,354	$1,929	$124,827	$8,198,274
25	0.15	$111,615	$2,297	$1,857	$115,769	$8,314,042
26	0.14	$103,347	$2,240	$1,788	$107,375	$8,421,418
27	0.13	$95,691	$2,185	$1,722	$99,598	$8,521,016
28	0.12	$88,603	$2,132	$1,658	$92,393	$8,613,409
29	0.11	$82,040	$2,079	$1,597	$85,716	$8,699,125
30	0.10	$75,963	$2,028	$1,538	$79,529	$8,778,654
31	0.09	$70,336	$1,979	$1,481	$73,796	$8,852,450
32	0.09	$65,126	$1,930	$1,426	$68,482	$8,920,932
33	0.08	$60,302	$1,883	$1,373	$63,558	$8,984,490
34	0.07	$55,835	$1,837	$1,322	$58,994	$9,043,483
35	0.07	$51,699	$1,791	$1,273	$54,763	$9,098,247
36	0.06	$47,870	$1,748	$1,226	$50,844	$9,149,090
37	0.06	$44,324	$1,705	$1,181	$47,210	$9,196,300
38	0.05	$41,040	$1,663	$1,137	$43,840	$9,240,139
39	0.05	$38,000	$1,622	$1,095	$40,717	$9,280,856
40	0.05	$35,186	$1,582	$1,054	$37,822	$9,318,679

Overhead 345 kV Steel Delta

First Costs		Losses		
Poles & Foundations	$2,818,800	Conductor	(bundled)	1590 ACSS
Conductor & Hardware	$1,810,400	Resistance	0.0354	ohms/mi
Site Work	$1,695,300	Peak Line Current		502 amps
Construction	$147,350	Load Growth		2.03 percent
Engineering	$385,740	Loss Factor		0.38
Sales Tax	$219,721	Energy Cost		48 mils/kWh
Project Management	$637,489	Energy Cost Escalation		1.2 percent

Year	PV Factor	First Costs	Losses	O&M	PV Cost	Cumulative PV
1	0.93	$1,007,210	$4,168	$4,594	$1,015,972	$1,015,972
2	0.86	$932,602	$4,066	$4,424	$941,092	$1,957,065
3	0.79	$863,520	$3,966	$4,260	$871,746	$2,828,811
4	0.74	$799,556	$3,869	$4,102	$807,527	$3,636,338
5	0.68	$740,329	$3,774	$3,951	$748,054	$4,384,393
6	0.63	$685,490	$3,682	$3,804	$692,976	$5,077,368
7	0.58	$634,713	$3,591	$3,663	$641,967	$5,719,336
8	0.54	$587,697	$3,503	$3,528	$594,728	$6,314,064
9	0.50	$544,164	$3,417	$3,397	$550,978	$6,865,042
10	0.46	$503,856	$3,333	$3,271	$510,460	$7,375,502
11	0.43	$466,533	$3,252	$3,150	$472,935	$7,848,437
12	0.40	$431,975	$3,172	$3,033	$438,180	$8,286,617
13	0.37	$399,977	$3,094	$2,921	$405,992	$8,692,609
14	0.34	$370,349	$3,018	$2,813	$376,180	$9,068,789
15	0.32	$342,916	$2,944	$2,709	$348,569	$9,417,358
16	0.29	$317,515	$2,872	$2,608	$322,995	$9,740,353
17	0.27	$293,995	$2,801	$2,512	$299,308	$10,039,662
18	0.25	$272,218	$2,733	$2,419	$277,370	$10,317,031
19	0.23	$252,053	$2,666	$2,329	$257,048	$10,574,079
20	0.21	$233,383	$2,600	$2,243	$238,226	$10,812,305
21	0.20	$216,095	$2,536	$2,160	$220,791	$11,033,097
22	0.18	$200,088	$2,474	$2,080	$204,642	$11,237,739
23	0.17	$185,267	$2,414	$2,003	$189,684	$11,427,422
24	0.16	$171,543	$2,354	$1,929	$175,826	$11,603,249
25	0.15	$158,836	$2,297	$1,857	$162,990	$11,766,238
26	0.14	$147,071	$2,240	$1,788	$151,099	$11,917,338
27	0.13	$136,177	$2,185	$1,722	$140,084	$12,057,422
28	0.12	$126,089	$2,132	$1,658	$129,879	$12,187,301
29	0.11	$116,749	$2,079	$1,597	$120,425	$12,307,726
30	0.10	$108,101	$2,028	$1,538	$111,667	$12,419,393
31	0.09	$100,094	$1,979	$1,481	$103,554	$12,522,947
32	0.09	$92,679	$1,930	$1,426	$96,035	$12,618,982
33	0.08	$85,814	$1,883	$1,373	$89,070	$12,708,052
34	0.07	$79,458	$1,837	$1,322	$82,617	$12,790,668
35	0.07	$73,572	$1,791	$1,273	$76,636	$12,867,305
36	0.06	$68,122	$1,748	$1,226	$71,096	$12,938,400
37	0.06	$63,076	$1,705	$1,181	$65,962	$13,004,362
38	0.05	$58,404	$1,663	$1,137	$61,204	$13,065,565
39	0.05	$54,078	$1,622	$1,095	$56,795	$13,122,360
40	0.05	$50,072	$1,582	$1,054	$52,708	$13,175,069

Underground 115 kV HPFF

First Costs		Losses		
Ducts & Vaults	$5,314,590	Cable		2500 kcmil
Cable & Hardware	$4,566,056	Resistance	0.0317	ohms/mi
Site Work	$2,694,722	Peak Line Current		502 amps
Construction	$299,414	Load Growth		2.03 percent
Engineering	$374,267	Loss Factor		0.38
Sales Tax	$468,283	Energy Cost		48 mils/kWh
Project Management	$1,253,345	Energy Cost Escalation		1.2 percent

Year	PV Factor	First Costs	Losses	O&M	PV Cost	Cumulative PV
1	0.93	$1,954,505	$3,735	$8,415	$1,966,655	$1,966,655
2	0.86	$1,809,727	$3,644	$8,104	$1,821,475	$3,788,130
3	0.79	$1,675,673	$3,554	$7,804	$1,687,031	$5,475,161
4	0.74	$1,551,549	$3,467	$7,514	$1,562,530	$7,037,691
5	0.68	$1,436,620	$3,382	$7,236	$1,447,238	$8,484,929
6	0.63	$1,330,203	$3,299	$6,968	$1,340,470	$9,825,400
7	0.58	$1,231,670	$3,218	$6,710	$1,241,598	$11,066,998
8	0.54	$1,140,435	$3,139	$6,462	$1,150,036	$12,217,034
9	0.50	$1,055,958	$3,062	$6,222	$1,065,242	$13,282,276
10	0.46	$977,739	$2,987	$5,992	$986,718	$14,268,994
11	0.43	$905,314	$2,914	$5,770	$913,998	$15,182,992
12	0.40	$838,254	$2,842	$5,556	$846,652	$16,029,644
13	0.37	$776,161	$2,773	$5,350	$784,284	$16,813,928
14	0.34	$718,667	$2,705	$5,152	$726,524	$17,540,451
15	0.32	$665,433	$2,638	$4,961	$673,032	$18,213,483
16	0.29	$616,142	$2,573	$4,778	$623,493	$18,836,977
17	0.27	$570,501	$2,510	$4,601	$577,612	$19,414,589
18	0.25	$528,242	$2,449	$4,430	$535,121	$19,949,710
19	0.23	$489,113	$2,389	$4,266	$495,768	$20,445,478
20	0.21	$452,882	$2,330	$4,108	$459,320	$20,904,798
21	0.20	$419,336	$2,273	$3,956	$425,565	$21,330,363
22	0.18	$388,274	$2,217	$3,810	$394,301	$21,724,664
23	0.17	$359,513	$2,163	$3,668	$365,344	$22,090,007
24	0.16	$332,882	$2,110	$3,533	$338,525	$22,428,532
25	0.15	$308,224	$2,058	$3,402	$313,684	$22,742,216
26	0.14	$285,393	$2,007	$3,276	$290,676	$23,032,893
27	0.13	$264,253	$1,958	$3,154	$269,365	$23,302,258
28	0.12	$244,678	$1,910	$3,038	$249,626	$23,551,884
29	0.11	$226,554	$1,863	$2,925	$231,342	$23,783,226
30	0.10	$209,772	$1,818	$2,817	$214,407	$23,997,633
31	0.09	$194,233	$1,773	$2,712	$198,718	$24,196,351
32	0.09	$179,846	$1,729	$2,612	$184,187	$24,380,538
33	0.08	$166,524	$1,687	$2,515	$170,726	$24,551,264
34	0.07	$154,189	$1,646	$2,422	$158,257	$24,709,521
35	0.07	$142,767	$1,605	$2,332	$146,704	$24,856,225
36	0.06	$132,192	$1,566	$2,246	$136,004	$24,992,229
37	0.06	$122,400	$1,527	$2,163	$126,090	$25,118,320
38	0.05	$113,333	$1,490	$2,083	$116,906	$25,235,226
39	0.05	$104,938	$1,453	$2,006	$108,397	$25,343,623
40	0.05	$97,165	$1,418	$1,931	$100,514	$25,444,137

Underground 115 kV XLPE

First Costs		Losses		
Ducts & Vaults	$6,009,792	Cable		3000 kcmil
Cable & Hardware	$6,573,210	Resistance	0.0268	ohms/mi
Site Work	$3,004,896	Peak Line Current		502 amps
Construction	$375,612	Load Growth		2.03 percent
Engineering	$469,515	Loss Factor		0.38
Sales Tax	$596,096	Energy Cost		48 mils/kWh
Admin/PM	$1,751,479	Energy Cost Escalation		1.2 percent

Year	PV Factor	First Costs	Losses	O&M	PV Cost	Cumulative PV
1	0.93	$2,451,912	$3,158	$8,415	$2,463,485	$2,463,485
2	0.86	$2,270,289	$3,080	$8,104	$2,281,473	$4,744,958
3	0.79	$2,102,119	$3,005	$7,804	$2,112,928	$6,857,886
4	0.74	$1,946,407	$2,931	$7,514	$1,956,852	$8,814,739
5	0.68	$1,802,228	$2,859	$7,236	$1,812,323	$10,627,062
6	0.63	$1,668,730	$2,789	$6,968	$1,678,487	$12,305,549
7	0.58	$1,545,120	$2,721	$6,710	$1,554,551	$13,860,100
8	0.54	$1,430,667	$2,654	$6,462	$1,439,783	$15,299,883
9	0.50	$1,324,692	$2,589	$6,222	$1,333,503	$16,633,385
10	0.46	$1,226,566	$2,525	$5,992	$1,235,083	$17,868,469
11	0.43	$1,135,710	$2,463	$5,770	$1,143,943	$19,012,412
12	0.40	$1,051,583	$2,403	$5,556	$1,059,542	$20,071,954
13	0.37	$973,688	$2,344	$5,350	$981,382	$21,053,336
14	0.34	$901,563	$2,286	$5,152	$909,001	$21,962,337
15	0.32	$834,780	$2,230	$4,961	$841,971	$22,804,309
16	0.29	$772,945	$2,176	$4,778	$779,899	$23,584,208
17	0.27	$715,690	$2,122	$4,601	$722,413	$24,306,621
18	0.25	$662,676	$2,070	$4,430	$669,176	$24,975,797
19	0.23	$613,589	$2,019	$4,266	$619,874	$25,595,672
20	0.21	$568,138	$1,970	$4,108	$574,216	$26,169,887
21	0.20	$526,053	$1,922	$3,956	$531,931	$26,701,818
22	0.18	$487,086	$1,874	$3,810	$492,770	$27,194,588
23	0.17	$451,006	$1,828	$3,668	$456,502	$27,651,091
24	0.16	$417,598	$1,784	$3,533	$422,915	$28,074,005
25	0.15	$386,665	$1,740	$3,402	$391,807	$28,465,812
26	0.14	$358,023	$1,697	$3,276	$362,996	$28,828,808
27	0.13	$331,503	$1,656	$3,154	$336,313	$29,165,121
28	0.12	$306,947	$1,615	$3,038	$311,600	$29,476,721
29	0.11	$284,210	$1,575	$2,925	$288,710	$29,765,431
30	0.10	$263,158	$1,537	$2,817	$267,512	$30,032,943
31	0.09	$243,664	$1,499	$2,712	$247,875	$30,280,818
32	0.09	$225,615	$1,462	$2,612	$229,689	$30,510,507
33	0.08	$208,903	$1,426	$2,515	$212,844	$30,723,351
34	0.07	$193,429	$1,391	$2,422	$197,242	$30,920,593
35	0.07	$179,101	$1,357	$2,332	$182,790	$31,103,383
36	0.06	$165,834	$1,324	$2,246	$169,404	$31,272,787
37	0.06	$153,550	$1,291	$2,163	$157,004	$31,429,792
38	0.05	$142,176	$1,260	$2,083	$145,519	$31,575,310
39	0.05	$131,644	$1,229	$2,006	$134,879	$31,710,189
40	0.05	$121,893	$1,199	$1,931	$125,023	$31,835,212

Underground 345 kV HPFF

First Costs	
Ducts & Vaults	$5,905,100
Cable & Hardware	$5,073,396
Site Work	$2,994,135
Construction	$332,682
Engineering	$499,023
Sales Tax	$520,314
Admin/PM	$1,309,436

Losses		
Cable		2500 kcmil
Resistance	0.0317	ohms/mi
Peak Line Current		502 amps
Load Growth		2.03 percent
Loss Factor		0.38
Energy Cost		48 mils/kWh
Energy Cost Escalation		1.2 percent

Year	PV Factor	First Costs	Losses	O&M	PV Cost	Cumulative PV
1	0.93	$2,171,672	$3,735	$8,415	$2,183,822	$2,183,822
2	0.86	$2,010,808	$3,644	$8,104	$2,022,556	$4,206,378
3	0.79	$1,861,859	$3,554	$7,804	$1,873,217	$6,079,595
4	0.74	$1,723,944	$3,467	$7,514	$1,734,925	$7,814,520
5	0.68	$1,596,244	$3,382	$7,236	$1,606,862	$9,421,382
6	0.63	$1,478,004	$3,299	$6,968	$1,488,271	$10,909,654
7	0.58	$1,368,522	$3,218	$6,710	$1,378,450	$12,288,104
8	0.54	$1,267,150	$3,139	$6,462	$1,276,751	$13,564,855
9	0.50	$1,173,287	$3,062	$6,222	$1,182,571	$14,747,426
10	0.46	$1,086,377	$2,987	$5,992	$1,095,356	$15,842,782
11	0.43	$1,005,904	$2,914	$5,770	$1,014,588	$16,857,370
12	0.40	$931,393	$2,842	$5,556	$939,791	$17,797,161
13	0.37	$862,401	$2,773	$5,350	$870,524	$18,667,685
14	0.34	$798,519	$2,705	$5,152	$806,376	$19,474,060
15	0.32	$739,370	$2,638	$4,961	$746,969	$20,221,029
16	0.29	$684,602	$2,573	$4,778	$691,953	$20,912,983
17	0.27	$633,890	$2,510	$4,601	$641,001	$21,553,984
18	0.25	$586,936	$2,449	$4,430	$593,815	$22,147,799
19	0.23	$543,459	$2,389	$4,266	$550,114	$22,697,913
20	0.21	$503,203	$2,330	$4,108	$509,641	$23,207,554
21	0.20	$465,928	$2,273	$3,956	$472,157	$23,679,711
22	0.18	$431,415	$2,217	$3,810	$437,442	$24,117,153
23	0.17	$399,459	$2,163	$3,668	$405,290	$24,522,442
24	0.16	$369,869	$2,110	$3,533	$375,512	$24,897,954
25	0.15	$342,471	$2,058	$3,402	$347,931	$25,245,885
26	0.14	$317,103	$2,007	$3,276	$322,386	$25,568,272
27	0.13	$293,614	$1,958	$3,154	$298,726	$25,866,998
28	0.12	$271,865	$1,910	$3,038	$276,813	$26,143,811
29	0.11	$251,727	$1,863	$2,925	$256,515	$26,400,326
30	0.10	$233,080	$1,818	$2,817	$237,715	$26,638,041
31	0.09	$215,815	$1,773	$2,712	$220,300	$26,858,341
32	0.09	$199,829	$1,729	$2,612	$204,170	$27,062,511
33	0.08	$185,027	$1,687	$2,515	$189,229	$27,251,740
34	0.07	$171,321	$1,646	$2,422	$175,389	$27,427,129
35	0.07	$158,630	$1,605	$2,332	$162,567	$27,589,696
36	0.06	$146,880	$1,566	$2,246	$150,692	$27,740,388
37	0.06	$136,000	$1,527	$2,163	$139,690	$27,880,079
38	0.05	$125,926	$1,490	$2,083	$129,499	$28,009,578
39	0.05	$116,598	$1,453	$2,006	$120,057	$28,129,635
40	0.05	$107,961	$1,418	$1,931	$111,310	$28,240,945

Underground 345 kV XLPE

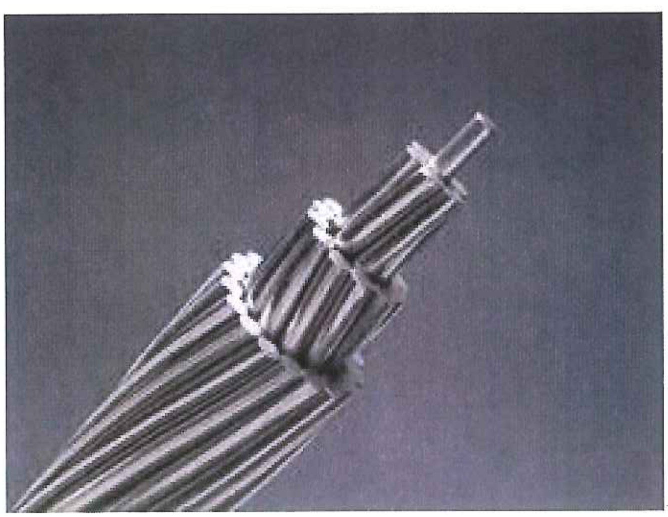
First Costs		Losses		
Ducts & Vaults	$7,030,624	Cable		3000 kcmil
Cable & Hardware	$7,689,745	Resistance	0.0268	ohms/mi
Site Work	$3,515,312	Peak Line Current		502 amps
Construction	$439,414	Load Growth		2.03 percent
Engineering	$659,121	Loss Factor		0.38
Sales Tax	$697,350	Energy Cost		48 mils/kWh
Admin/PM	$1,939,134	Energy Cost Escalation		1.2 percent

Year	PV Factor	First Costs	Loss	O&M	PV Cost	Cumulative PV
1	0.93	$2,868,397	$3,158	$8,415	$2,879,970	$2,879,970
2	0.86	$2,655,923	$3,080	$8,104	$2,667,107	$5,547,077
3	0.79	$2,459,188	$3,005	$7,804	$2,469,997	$8,017,074
4	0.74	$2,277,026	$2,931	$7,514	$2,287,471	$10,304,546
5	0.68	$2,108,357	$2,859	$7,236	$2,118,452	$12,422,998
6	0.63	$1,952,183	$2,789	$6,968	$1,961,940	$14,384,938
7	0.58	$1,807,577	$2,721	$6,710	$1,817,008	$16,201,946
8	0.54	$1,673,682	$2,654	$6,462	$1,682,798	$17,884,744
9	0.50	$1,549,706	$2,589	$6,222	$1,558,517	$19,443,260
10	0.46	$1,434,913	$2,525	$5,992	$1,443,430	$20,886,691
11	0.43	$1,328,623	$2,463	$5,770	$1,336,856	$22,223,547
12	0.40	$1,230,206	$2,403	$5,556	$1,238,165	$23,461,712
13	0.37	$1,139,080	$2,344	$5,350	$1,146,774	$24,608,486
14	0.34	$1,054,704	$2,286	$5,152	$1,062,142	$25,670,628
15	0.32	$976,577	$2,230	$4,961	$983,768	$26,654,397
16	0.29	$904,238	$2,176	$4,778	$911,192	$27,565,589
17	0.27	$837,258	$2,122	$4,601	$843,981	$28,409,570
18	0.25	$775,239	$2,070	$4,430	$781,739	$29,191,309
19	0.23	$717,814	$2,019	$4,266	$724,099	$29,915,409
20	0.21	$664,642	$1,970	$4,108	$670,720	$30,586,128
21	0.20	$615,409	$1,922	$3,956	$621,287	$31,207,415
22	0.18	$569,824	$1,874	$3,810	$575,508	$31,782,923
23	0.17	$527,614	$1,828	$3,668	$533,110	$32,316,034
24	0.16	$488,532	$1,784	$3,533	$493,849	$32,809,882
25	0.15	$452,344	$1,740	$3,402	$457,486	$33,267,368
26	0.14	$418,837	$1,697	$3,276	$423,810	$33,691,178
27	0.13	$387,812	$1,656	$3,154	$392,622	$34,083,800
28	0.12	$359,085	$1,615	$3,038	$363,738	$34,447,538
29	0.11	$332,487	$1,575	$2,925	$336,987	$34,784,525
30	0.10	$307,858	$1,537	$2,817	$312,212	$35,096,737
31	0.09	$285,054	$1,499	$2,712	$289,265	$35,386,002
32	0.09	$263,939	$1,462	$2,612	$268,013	$35,654,015
33	0.08	$244,388	$1,426	$2,515	$248,329	$35,902,344
34	0.07	$226,285	$1,391	$2,422	$230,098	$36,132,442
35	0.07	$209,523	$1,357	$2,332	$213,212	$36,345,654
36	0.06	$194,003	$1,324	$2,246	$197,573	$36,543,227
37	0.06	$179,632	$1,291	$2,163	$183,086	$36,726,314
38	0.05	$166,326	$1,260	$2,083	$169,669	$36,895,982
39	0.05	$154,006	$1,229	$2,006	$157,241	$37,053,223
40	0.05	$142,598	$1,199	$1,931	$145,728	$37,198,951

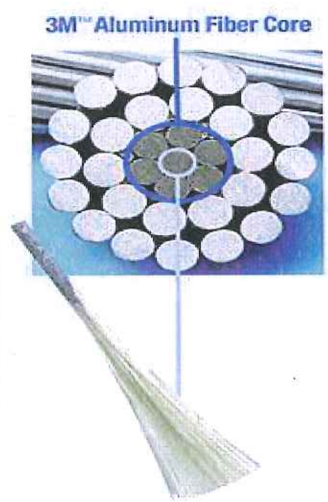
D. Photos of Transmission Technologies

Figure C-1: Archers Lane 345-kV Transition Station

Figure C-2: ACSS HTLS conductor (left) and an ACCR composite conductor (right)

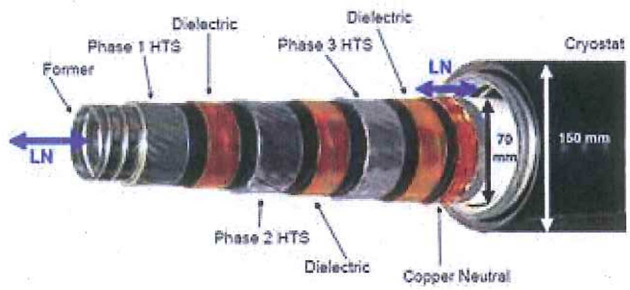


Source: Alcan Products Catalog



Source: 3M Corporation

Figure C-3: Triax Superconducting Cable (NOTE: LN is Liquid Nitrogen)



Source: Superconductivity

E. LiDAR

LiDAR aerial patrols have become the best new technological innovation in regards to transmission line maintenance in the State of Connecticut. The equipment consists of a precise navigation system and a scanning laser. The laser transmits light pulses and measures reflection times. Distances to objects are calculated and then combined with the precise positional data from the navigation system. This produces very accurate LiDAR survey points with associated coordinate values, which are classified into categories such as ground, structure, conductor, and vegetation post-flight and are then turned into ASCII files for use by the utility. Using the imaging software in LiDAR in conjunction with transmission line design software like PLS-CADD or some similar platform allows the utility to make quick and accurate assessments of line clearances. LiDAR has the ability to produce 3-D models and can identify:

- Span length and height at midpoint (sag)
- Conductor blowout (when the outer most conductor swings away from the tower)

Figure D-1: Hazard tree in transmission ROW

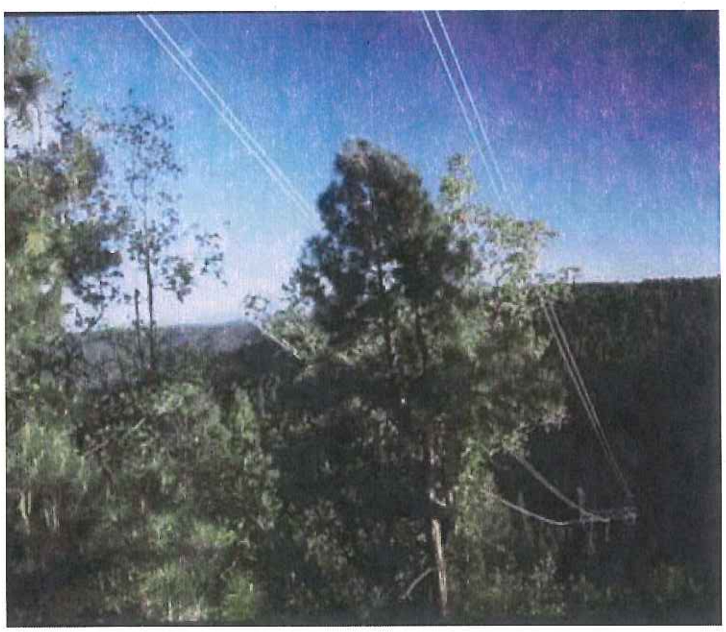
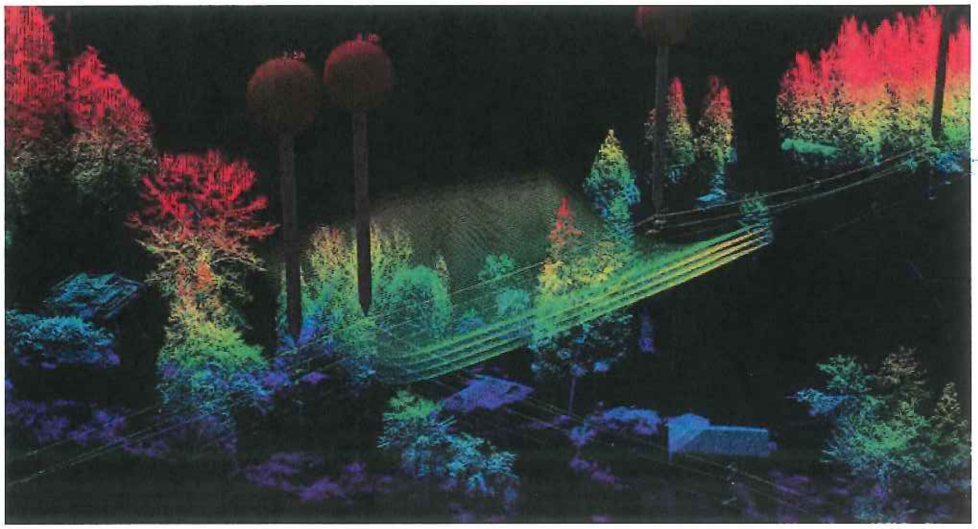


Figure D-2: LiDAR 3-D image of transmission ROW



LiDAR surveys of NERC-designated transmission lines have been initiated and are currently scheduled on a 3-year cycle. These surveys have increased maintenance expenditures and will add $500 per mile of surveyed line every three (3) years.[1]

While the LiDAR patrols and NERC VM Standard FAC-003-1 have increased transmission line maintenance costs, these expenditures are expected to decrease future maintenance costs associated with line outages and vegetation management while improving transmission reliability.[1, 2, 3, 4, and 5]

F. EMF

Table E-1 (part C) shows the very significant reduction in the magnetic field that result from split-phasing, especially at distances of 20 to 100 ft. from the right-of-way (ROW) centerline. Electric fields with split phasing are only incrementally lower than those for a delta configuration. First costs associated with split-phasing at 345 kV are, typically 40 percent higher than those for a single-circuit H-Frame design (R.I. Study).

Table E-2 (part C) shows similar reductions for a split-phasing arrangement at 115 kV.

Table E-1: 345 kV EMF Levels from the Rhode Island Study

Configuration and Field	Maximum Field	Distance from Centerline of Structure (ft.)						
		0	20	40	60	80	100	200
A. Horizontal								
Magnetic field (mG)	210 at 0 ft.	210	208	141	77.1	45.4	29.4	7.39
Electric field (kV/m)	4.32 at 30 ft.	2.73	3.67	3.75	1.89	0.92	0.5	0.07
B. Davit (Delta)								
Magnetic field (mG)	135 at - 10 ft.	132	95.7	58.7	35.6	22.8	15.6	4.23
Electric field (kV/m)	3.64 at - 20 ft.	2.54	1.90	1.61	0.99	0.58	0.36	0.07
C. Split-phase (Vertical)								
Magnetic field (mG)	67.4 at 0 ft.	67.4	52.8	29.2	15.5	8.69	5.2	0.83
Electric field (kV/m)	3.00 at 10 ft.	2.45	2.99	1.36	0.7	0.46	0.3	0.05

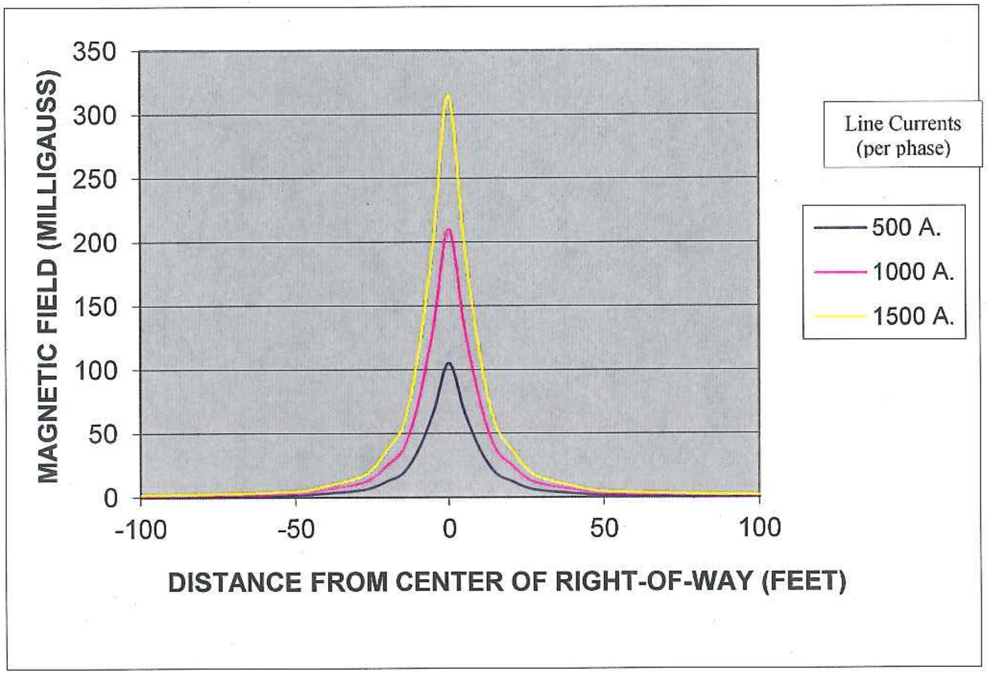
Table E-2: Calculated 115 kV EMF Levels for Various Conductor Configurations

Configuration and Field	Maximum Field	Distance from Centerline of Structure (ft.)						
		0	20	40	60	80	100	200
A. Horizontal								
Magnetic field (mG)	181 at 0 ft.	181	141	77.3	37.0	22.9	16.9	3.20
Electric field (kV/m)	1.16 at 0 ft.	0.40	1.14	0.76	0.34	0.16	0.095	0.015
B. Davit (Delta)								
Magnetic field (mG)	109 at 1 ft.	108	82.3	43.4	22.9	13.3	10.1	1.83
Electric field (kV/m)	0.945 at 12 ft.	0.72	0.90	0.46	0.20	0.11	0.069	0.015
C. Split-phase (Vertical)								
Magnetic field (mG)	43.4 at 0 ft.	43.4	29.7	13.7	6.40	2.97	1.83	0
Electric field (kV/m)	0.72 at 12 ft.	0.58	0.65	0.23	0.057	0.019	0.011	0

Table E-3: Calculated EMF Levels for Single- and Double-circuit 115 kV Overhead Lines

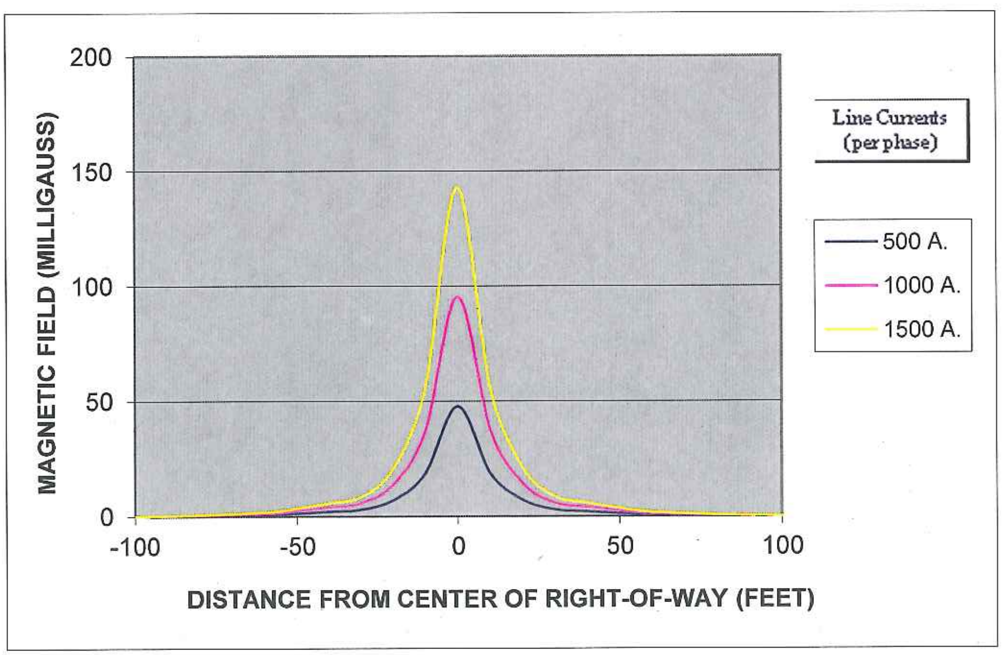
Configuration and Field	Maximum Field	Distance from Centerline of Structure (ft.)						
		0	20	40	60	80	100	200
A. Single-circuit (vertical)								
Magnetic field (mG)	102 at 8ft	93.9	90.1	53.5	31.3	19.9	13.7	5.3
Electric field (kV/m)	1.18 at 8ft	1.02	0.87	0.26	0.03	0.04	0.05	0.02
B. Double-circuit (vertical)								
Magnetic field (mG)	171 at 0ft	171	139	87.8	51.9	34.4	24.4	6.1
Electric field (kV/m)	1.99 at 0ft	1.99	1.21	0.32	0.04	0.05	0.06	0.02

Figure E-1: Magnetic Field Profiles for 115 kV XLPE Line with Horizontal Cable Arrangement



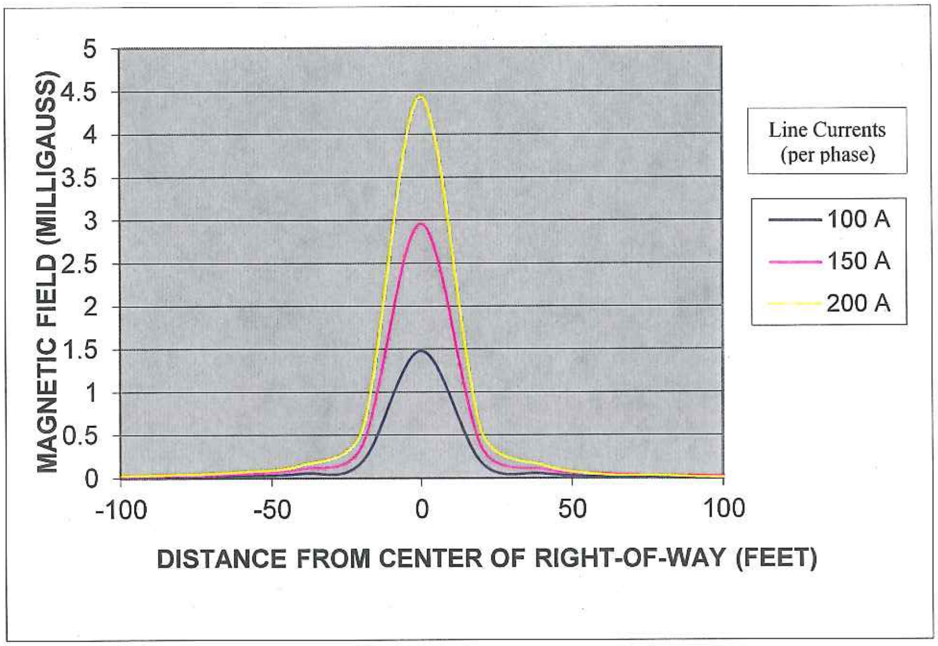
Source: Connecticut Siting Council and Acres International Corp[1]

Figure E-2: Magnetic Field Profiles for 115 kV XLPE Line with Delta Cable Arrangement



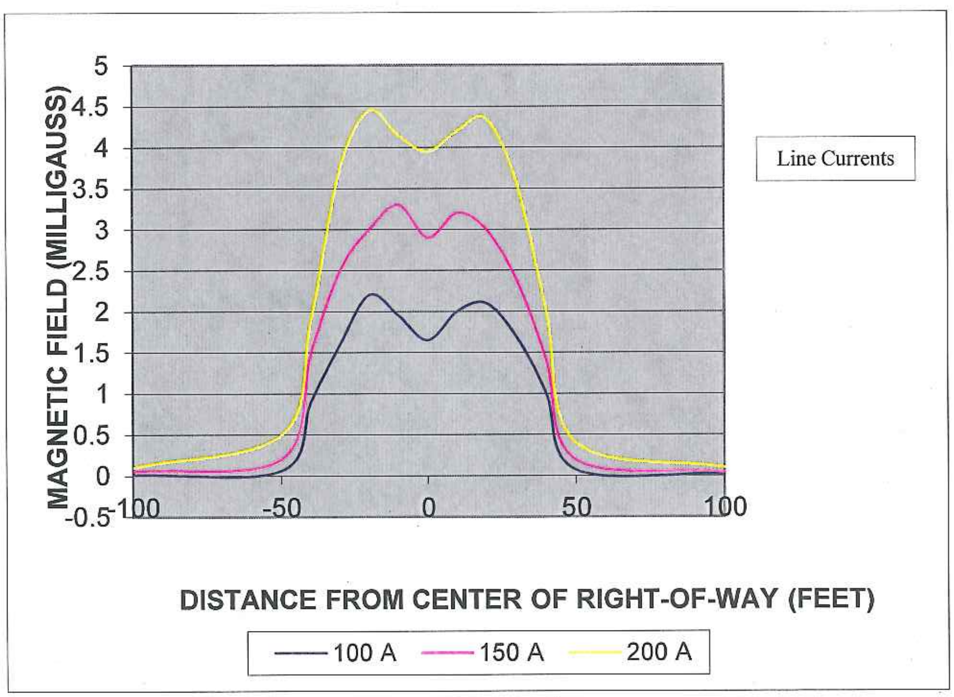
Source: Connecticut Siting Council and Acres International Corp[1]

Figure E-3: Magnetic Field Profiles for Typical 345 kV HPFF Line*



Source: Connecticut Siting Council and Acres International Corp[1]

Figure E-4: Average of Magnetic Field Measurements for 345 kV HPFF Line*



Source: CL&P[2]

G. Loss Cost Calculation Method

G.1 Loss Cost Formula

The following formulas are used in the electric industry to estimate the cost of transmission losses. The loss calculations are based on a peak load current for a given line and a system loss factor.

EC (Energy Cost) = $3 \times R \times I^2 \times 8760 \times LF \times AIC$

DC (Demand Cost) = $3 \times R \times I^2 \times IDC \times LIF$

EC = energy cost, $ / yr.

DC = demand cost, $ / yr.

R = conductor resistance (ohms/phase/mile) X line length (miles)

I = peak load current on the line (amperes)

8760 = hours / year

LF = loss factor (average loss / peak loss)

AIC = average incremental energy cost for the year ($ / kWh)

IDC = incremental demand cost ($ / kW-yr.)

NOTES: AIC is based on the wholesale price of electricity ($0.048/kWh in this report). Since transmission losses occur at the wholesale level, they should not include the cost of distribution facilities or other costs. IDC is zero since this evaluation is not being done for system capacity reasons.[1]

Example Calculation
Conductor = 1272 ACSS (R = 0.08712 ohms/mile)
Peak load current = 502 amperes (equal to 100 MVA at 115 kV)
Loss Factor = 0.38 (same for CT utilities)
AIC = $0.048 / kWh (consistent with previous reports)
Demand Cost = $0.0
Initial cost of losses = $(3)(0.08712)(502)^2$ (1kW/1000W)(8760 hr /year) (0.38) ($0.048/kWh)
= $10,524
First year cost of losses = ($10,524)(1.012)(1/1.08)(1.0203^2) = $10,266

References:

1. Connecticut Siting Council, RE: Life-Cycle 2011, Investigation into the Life-Cycle Costs of Electric Transmission Lines, January 17, 2012, Hearing Transcript, pages 14 - 15.

H. Electric and Magnetic Fields Best Management Practices for the Construction of Electric Transmission Lines in Connecticut (Connecticut Siting Council)

Electric and Magnetic Fields Best Management Practices
For the Construction of Electric Transmission Lines in Connecticut

Approved on December 14, 2007

I. Introduction

To address a range of concerns regarding potential health risks from exposure to transmission line electric and magnetic fields (EMF), whether from electric transmission facilities or other sources, the Connecticut Siting Council (Council) (in accordance with Public Act 04-246) issues this policy document "*Best Management Practices for the Construction of Electric Transmission Lines in Connecticut*." It references the latest information regarding scientific knowledge and consensus on EMF health concerns; it also discusses advances in transmission-facility siting and design that can affect public exposure to EMF.

Electric and magnetic fields (EMF) are two forms of energy that surround an electrical device. The strength of an electric field (EF) is proportional to the amount of electric voltage at the source, and decreases rapidly with distance from the source, diminishing even faster when interrupted by conductive materials, such as buildings and vegetation. The level of a magnetic field (MF) is proportional to the amount of electric current (not voltage) at the source, and it, too, decreases rapidly with distance from the source; but magnetic fields are not easily interrupted, as they pass through most materials. EF is often measured in units of kilovolts per meter (kV/m). MF is often measured in units of milligauss (mG).

Transmission lines are common sources of EMF, as are other substantial components of electric power infrastructure, ranging from transformers at substations to the wiring in a home. However, any piece of machinery run by electricity can be a source of EMF: household objects as familiar as electric tools, hair dryers, televisions, computers, refrigerators, and electric ovens.

In the U.S., EMF associated with electric power has a frequency of 60 cycles per second (or 60 Hz). Estimated average background levels of 60-Hz MF in most homes, away from appliances and electrical panels, range from 0.5 to 5.0 mG (NIEHS, 2002). MF near operating appliances such as an oven, fan, hair dryer, television, etc. can range from 10's to 100's of mG. Many passenger trains, trolleys, and subways run on electricity, producing MF: for instance, MF in a Metro-North Railroad car averages about

40-60 mG, increasing to 90-145 mG with acceleration (Bennett Jr., W. 1994). As a point of comparison to these common examples, the Earth itself has an MF of about 570 mG (USGS 2007). Unlike the MF associated with power lines, appliances, or computers, the Earth's MF is steady; in every other respect, however, the Earth's MF has the same characteristics as MF emanating from man-made sources.

Concerns regarding the health effects of EMF arise in the context of electric transmission lines and distribution lines, which produce time-varying EMF, sometimes called extremely-low frequency electric and magnetic fields, or ELF-EMF. As the weight of scientific evidence indicates that exposure to electric fields, beyond levels traditionally established for safety, does not cause adverse health effects, and as safety concerns for electric fields are sufficiently addressed by adherence to the National Electrical Safety Code, as amended, health concerns regarding EMF focus on MF rather than EF.

MF levels in the vicinity of transmission lines are dependent on the flow of electric current through them and fluctuate throughout the day as electrical demand increases and decreases. They can range from about 5 to 150 mG, depending on current load, height of the conductors, separation of the conductors, and distance from the lines. The level of the MF produced by a transmission line decreases with increasing distance from the conductors, becoming indistinguishable from levels found inside or outside homes (exclusive of MF emanating from sources within the home) at a distance of 100 to 300 feet, depending on the design and current loading of the line (NIEHS, 2002).

In Connecticut, existing and proposed transmission lines are designed to carry electric power at voltages of 69, 115, or 345 kilovolts (kV). Distribution lines, i.e. those lines directly servicing the consumer's building, typically operate at voltages below 69 kV and may produce levels of MF similar to those of transmission lines. The purpose of this document is to address engineering practices for proposed electric transmission lines with a design capacity of 69 kV or more and MF health concerns related to these projects, but not other sources of MF.

II. Health Concerns from Power-Line MF

While more than 40 years of scientific research has addressed many questions about EMF, the continuing question of greatest interest to public health agencies is the possibility of an association between time weighted MF exposure and demonstrated health effects. The World Health Organization (WHO) published its latest findings on this question in an Electromagnetic Fields and Public Health fact sheet, June 2007. (http://www.who.int/mediacentre/factsheets/fs322/en/index.html) The fact sheet is based on a review by a WHO Task Group of scientific experts who assessed risks associated with ELF-EMF. As part of this review, the group examined studies related to MF exposure and various health effects, including childhood cancers, cancers in adults, developmental disorders, and neurobehavioral effects, among others. Particular attention was paid to leukemia in children. The Task Group concluded "that scientific evidence supporting an association between ELF magnetic field exposure and all of these health effects is much weaker than for childhood leukemia". (WHO, 2007) For childhood leukemia, WHO concluded recent studies do not alter the existing position taken by the International Agency for Research on Cancer (IARC) in 2002, that ELF-MF is "possibly carcinogenic to humans."

Some epidemiology studies have reported an association between MF and childhood leukemia, while others have not. Two broad statistical analyses of these studies as a pool reported an association with estimated average exposures greater than 3 to 4 mG, but at this level of generalization it is difficult to determine whether the association is significant. In 2005, the National Cancer Institute (NCI) stated, "Among more recent studies, findings have been mixed. Some have found an association; others have not . . . . Currently, researchers conclude that there is limited evidence that magnetic fields from power lines cause childhood leukemia, and that there is inadequate evidence that these magnetic fields cause other cancers in children." The NCI stated further: "Animal studies have not found that magnetic field exposure is associated with increased risk of cancer. The absence of animal data supporting carcinogenicity makes it biologically less likely that magnetic field exposures in humans, at home or at work, are linked to increased cancer risk."

The American Medical Association characterizes the EMF health-effect literature as "inconsistent as to whether a risk exists." The National Institute of Environmental Health Sciences (NIEHS) concluded in 1999 that EMF exposure could not be recognized as "*entirely safe*" due to some statistical evidence of a link with childhood leukemia. Thus, although no public health agency has found that scientific research suggests a causal relationship between EMF and cancer, the NIEHS encourages "inexpensive and safe reductions in exposure" and suggests that the power industry continue its current practice of siting power lines to reduce exposures" rather than regulatory guidelines (NIEHS, 1999, pp. 37-38). In 2002 NIEHS restated that while this evidence was "weak" it was "still sufficient to warrant limited concern" and recommended "continued education on ways of reducing exposures" (NIEHS, 2002, p. 14).

Reviews by other study groups, including IARC (2002), the Australian Radiation Protection and Nuclear Safety Agency (ARPANSA) (2003), the British National Radiation Protection Board (NRPB) (2004a), and the Health Council of the Netherlands ELF Electromagnetic Fields Committee (2005), are similar to NIEHS and NCI in their uncertainty about reported associations of MF with childhood leukemia. In 2004, the view of the NRPB was:

> "[T]he epidemiological evidence that time-weighted average exposure to power frequency magnetic fields above 0.4 microtesla [4 mG] is associated with a small absolute raised risk of leukemia in children is, at present, an observation for which there is no sound scientific

> explanation. There is no clear evidence of a carcinogenic effect of ELF EMFS in adults and no plausible biological explanation of the association can be obtained from experiments with animals or from cellular and molecular studies. Alternative explanations for this epidemiological association are possible…Thus: any judgments developed on the assumption that the association is causal would be subject to a very high level of uncertainty." (NRPB, 2004a, p. 15)

Although IARC classified MF as "possibly carcinogenic to humans" based upon pooling of the results from several epidemiologic studies, IARC further stated that the evidence suggesting an association between childhood leukemia and residential MF levels is "limited," with "inadequate" support for a relation to any other cancers. The WHO Task Group concluded "the evidence related to childhood leukemia is not strong enough to be considered causal" (WHO, 2007).

The Connecticut Department of Public Health (DPH) has produced an EMF Health Concerns Fact Sheet (May 2007) that incorporates the conclusions of national and international health panels. The fact sheet states that while "the current scientific evidence provides no definitive answers as to whether EMF exposure can increase health risks, there is enough uncertainty that some people may want to reduce their exposure to EMF." [http://www.dph.state.ct.us/Publications/brs/eoha/emf_2004.pdf]

In the U.S., there is no state or federal exposure standards for 60-Hz MF based on demonstrated health effects. Nor are there any such standards world-wide. Among those international agencies that provide guidelines for acceptable MF exposure to the general public, the International Commission on Non-Ionizing Radiation Protection established a level of 833 mG, based on an extrapolation from experiments involving transient neural stimulation by MF at much higher exposures. Using a similar approach, the International Committee on Electromagnetic Safety calculated a guideline of 9,040 mG for exposure to workers and the general public (ICNIRP, 1998; ICES/IEEE, 2002). This situation reflects the lack of credible scientific evidence for a causal relationship between MF exposure and adverse health effects.

III. Policy of the Connecticut Siting Council

The Council recognizes that a causal link between power-line MF exposure and demonstrated health effects has not been established, even after much scientific investigation in the U.S. and abroad. Furthermore, the Council recognizes that timely additional research is unlikely to prove the safety of power-line MF to the satisfaction of all. Therefore, the Council will continue its cautious approach to transmission line siting that has guided its Best Management Practices since 1993. This continuing policy is based on the Council's recognition of an agreement with conclusions shared by a wide range of public health consensus groups, and also, in part, on a review which the Council commissioned as to the weight of scientific evidence regarding possible links between power-line MF and adverse health effects. Under this policy, the Council will continue to advocate the use of effective no-cost and low-cost technologies and management techniques on a project-specific basis to reduce MF exposure to the public while allowing for the development of efficient and cost-effective electrical transmission projects. This approach does not imply that MF exposure will be lowered to any specific threshold or exposure limit, nor does it imply MF mitigation will be achieved with no regard to cost.

The Council will develop its precautionary guidelines in conjunction with Section 16-50p(i) of the Connecticut General Statutes, enacted by the General Assembly to call special attention to their concern for children. The Act restricts the siting of overhead 345-kV transmission lines in areas where children congregate, subject to technological feasibility. These restrictions cover transmission lines adjacent to "residential areas, public or private schools, licensed child day-care facilities, licensed youth camps, or public playgrounds."

Developing Policy Guidelines

One important way the Council seeks to update its Best Management Practices is to integrate policy with specific project development guidelines. In this effort, the Council has reviewed the actions of other states. Most states either have no specific guidelines or have established arbitrary MF levels at the edge of a right-of-way that are not based on any demonstrated health effects. California, however, established a no-cost/low-cost precautionary-based EMF policy in 1993 that was re-affirmed by the California Public Utilities Commission in 2006. California's policy aims to provide significant MF reductions at no cost or low cost, a precautionary approach consistent with the one Connecticut has itself taken since 1993, consistent with the conclusions of the major scientific reviews, and consistent with the policy recommendations of the Connecticut Department of Public Health and the WHO. Moreover, California specifies certain benchmarks integral to its policy. The benchmark for "low-cost/no-cost" is an increase in aggregate project costs of zero to four percent. The benchmark for "significant MF reduction" is an MF reduction of at least 15 percent. With a policy similar to Connecticut's, and concrete benchmarks as well, California offers the Council a useful model in developing policy guidelines.

No-Cost/Low-Cost MF Mitigation

The Council seeks to continue its precautionary policy, in place since 1993, while establishing a standard method to allocate funds for MF mitigation methods. The Council recognizes California's cost allotment strategy as an effective method to achieve MF reduction goals; thus, the Council will follow a similar strategy for no-cost/low-cost MF mitigation.

The Council directs the Applicant to initially develop a Field Management Design Plan that depicts the proposed transmission line project designed according to standard good utility practice and incorporating "no-cost" MF mitigation design features. The Applicant shall then modify the base design by adding low-cost MF mitigation design features specifically where portions of the project are adjacent to residential areas, public or private schools, licensed child day-care facilities, licensed youth camps, or public playgrounds.

The overall cost of low-cost design features are to be calculated at four percent of the initial Field Management Design Plan, including related substations. Best estimates of the total project costs during the Council proceedings should be employed, and the amounts proposed to be incurred for MF mitigation should be excluded. It is important to note that the four percent guideline is not an absolute cap, because the Council does not want to eliminate prematurely a potential measure that might be available and effective but would cost more than the four percent, or exclude arbitrarily an area adjacent to the ROW that might be suitable for MF mitigation. Nor is the four percent an absolute threshold, since the Council wants to encourage the utilities to seek effective field reduction measures costing less than four percent. In general, the Council recognizes that projects can vary widely in the extent of their impacts on statutory facilities, necessitating some variance above and below the four percent figure.

The four percent guideline for low-cost mitigation should aim at a magnetic field reduction of 15 percent or more at the edge of the utility's ROW. This 15 percent reduction should relate specifically to those portions of the project where the expenditures would be made. While experience with transmission projects in Connecticut since 1993 has shown that no-cost/low-cost designs can and do achieve reductions in MF on the order of 15 percent, the 15 percent guideline is no more absolute than the four percent one, nor must the two guidelines be correlated by rote. The nature of guidelines is to be constructive, rather than absolute.

The Council will consider minor increases above the four percent guideline if justified by unique circumstances, but not as a matter of routine. Any cost increases above the four percent guideline should result in mitigation comparably above 15 percent, and the total costs should still remain relatively low.

Undergrounding transmission lines puts MF issues out of sight, but it should not necessarily put them out of mind. With that said, soils and other fill materials do not shield MF, rather, MF is reduced by the underground cable design (refer to page 9 for further information). However, special circumstances may warrant some additional cost in order to achieve further MF mitigation for underground lines. The utilities are encouraged, prior to submitting their application to the Council, to determine whether a project involves such special circumstances. Note that the extra costs of undergrounding done for purposes other than MF mitigation should be counted in the base project cost and not as part of the four percent mitigation spending.

Additionally, the Council notes two general policies it follows in updating its EMF Best Management Practices and conducting other matters within its jurisdiction. One is a policy to support and monitor ongoing study. Accordingly, the Council, during the public hearing process for new transmission line projects, will consider and review evidence of any new developments in scientific research addressing MF and public health effects or changes in scientific consensus group positions regarding MF. The second is a policy to encourage public participation and education. The Council will continue to conduct public hearings open to all, update its website to contain the latest information regarding MF health effect research, and revise these Best Management Practices to take account of new developments in MF health effect research or in methods for achieving no-cost/low-cost MF mitigation.

The Council will also require that notices of proposed overhead transmission lines provided in utility bill enclosures pursuant to Conn. Gen. Stats. §16-50*l*(b) state the proposed line will meet the Council's Electric and Magnetic Fields Best Management Practices, specifying the design elements planned to reduce magnetic fields. The bill enclosure notice will inform residents how to obtain siting and MF information specific to the proposed line at the Council's website; this information will also be available at each respective town hall. Phone numbers for follow-up information will be made available, including those of DPH, and utility representatives. The project's final post-construction structure and conductor specifications including calculated MF levels shall also be available at the Council's website and each respective town hall.

Finally, we note that Congress has directed the Department of Energy (DOE) periodically to assess congestion along critical transmission paths or corridors and apply special designation to the most significant ones. Additionally, Congress has given the Federal Regulatory Commission supplemental siting authority in DOE designated areas. This means the Council must complete all matters in an expeditious and timely manner. Accordingly, the cooperation of all parties will be of particular importance in fulfilling the policies set forth above.

IV. MF Best Management Practices: Further Management Considerations

The Council's EMF Best Management Practices will apply to the construction of new electric transmission lines in the State, and to modifications of existing lines that require a certificate of environmental compatibility and public need. These practices are intended for use by public service utilities and the Council when considering the installation of such new or modified electric transmission lines. The practices are based on the established Council policy of reducing MF levels at the edge of a right-of-way (ROW), and in areas of particular interest, with no-cost/low-cost designs that do not compromise system reliability or worker safety, or environmental and aesthetic project goals.

Several practical engineering approaches are currently available for reducing MF, and more may be developed as technology advances. In proposing any particular methods of MF mitigation for a given project, the Applicant shall provide a detailed rationale to the Council that supports the proposed MF mitigation measures. The Council has the option to retain a consultant to confirm that the Field Management Design Plan and the proposed MF reduction strategies are consistent with these EMF Best Management Practices.

A. MF Calculations

When preparing a transmission line project, an applicant shall provide design alternatives and calculations of MF for pre-project and post-project conditions, under 1) peak load conditions at the time of the application filing, and 2) projected seasonal maximum 24-hour average current load on the line anticipated within five years after the line is placed into operation. This will allow for an evaluation of how MF levels differ between alternative power line configurations. The intent of requiring various design options is to achieve reduced MF levels when possible through practical design changes. The selection of a specific design will also be affected by other practical factors, such as the cost, system reliability, aesthetics, and environmental quality.

MF values shall be calculated from the ROW centerline out to a distance of 300 feet on each side of the centerline, at intervals of 25 feet, including at the edge of the ROW. In accordance with industry practice, the calculation shall be done at the location of maximum line sag (typically mid-span), and shall provide MF values at 1 meter above ground level, with the assumption of flat terrain and balanced currents. The calculations shall assume "all lines in" and projected load growth five years beyond the time the lines are expected to be put into operation, and shall include changes to the electric system approved by the Council and the Independent System Operator – New England.

As part of this determination, the applicant shall provide the locations of, and anticipated MF levels encompassing, residential areas, private or public schools, licensed child day care facilities, licensed youth camps, or public playgrounds within 300 feet of the proposed transmission line. The Council, at its discretion, may order the field measurement of post-construction MF values in select areas, as appropriate.

B. Buffer Zones and Limits on MF

As enacted by the General Assembly in Section 4 of Public Act No. 04-246, a buffer zone in the context of transmission line siting is deemed, at minimum, to be the distance between the proposed transmission line and the edge of the utility ROW. Buffer zone distances may also be guided by the standards presented in the National Electrical Safety Code (NESC), published by the Institute of Electrical and Electronic Engineers (IEEE). These standards provide for the safe installation, operation, and maintenance of electrical utility lines, including clearance requirements from vegetation, buildings, and other natural and man-made objects that may arise in the ROW. The safety of power-line workers and the general public are considered in the NESC standards. None of these standards include MF limits.

Since 1985, in its reviews of proposed transmission-line facilities, the Massachusetts Energy Facilities Siting Board has used an edge-of-ROW level of 85 mG as a benchmark for comparing different design alternatives. Although a ROW-edge level in excess of this value is not prohibited, it may trigger a more extensive review of alternatives.

In assessing whether a right-of-way provides a sufficient "buffer zone," the Council will emphasize compliance with its own Best Management Practices, but may also take into account approaches of other states, such as those of Florida, Massachusetts, and New York.

A number of states have general MF guidelines that are designed to maintain the 'status quo', i.e., that fields from new transmission lines not exceed those of existing transmission lines. In 1991, the New York Public Service Commission established an interim policy based on limits to MF. It required new high-voltage transmission lines to be designed so that the maximum magnetic fields at the edge of the ROW, one meter above ground, would not exceed 200 mG if the line were to operate at its highest continuous current rating. This 200 mG level represents the maximum calculated magnetic field level for 345 kV lines that were then in operation in New York State.

The Florida Environmental Regulation Commission established a maximum magnetic field limit for new transmission lines and substations in 1989. The MF limits established for the edge of 230-kV to 500-kV transmission line ROWs and the property boundaries for substations ranged from 150 mG to 250 mG, depending on the voltage of the new transmission line and whether an existing 500-kV line was already present.

Although scientific evidence to date does not warrant the establishment of MF exposure limits at the edge of a ROW, the Council will continue to monitor the ways in which states and other jurisdictions determine MF limits on new transmission lines.

C. Engineering Controls that Modify MF Levels

When considering an overhead electric transmission-line application, the Council will expect the applicant to examine the following Engineering Controls to limit MF in publicly accessible areas: distance, height, conductor separation, conductor configuration, optimum phasing, increased voltage, and underground installation. Any design change may also affect the line's impedance, corona discharge, mechanical behavior, system performance, cost, noise levels and visual impact. The Council will consider all of these factors in relation to the MF levels achieved by any particular Engineering Control. Thus, utilities are encouraged to evaluate other possible Engineering Controls that might be applied to the entire line, or just specific segments, depending upon land use, to best minimize MF at a low or no cost.

Consistent with these Best Management Practices and absent line performance and visual impacts, the Council expects that applicants will propose no-cost/low-cost measures to reduce magnetic fields by one or more engineering controls including:

Distance

MF levels from transmission lines (or any electrical source) decrease with distance; thus, increased distance results in lower MF. Horizontal distances can be increased by purchasing wider ROWs, where available. Other distances can be increased in a variety of ways, as described below.

Height of Support Structures

Increasing the vertical distance between the conductors and the edge of the ROW will decrease MF: this can be done by increasing the height of the support structures. The main drawbacks of this approach are an increase in the cost of supporting structures, possible environmental effects from larger foundations, potential detrimental visual effects, and the modest MF reductions achieved (unless the ROW width is unusually narrow).

Conductor Separation

Decreasing the distances between individual phase conductors can reduce MF. Because at any instant in time the sum of the currents in the individual phase conductors is zero, or close to zero, moving the conductors closer together improves their partial cancellation of each other's MF. In other words, the net MF produced by the closer conductors reduces the MF level associated with the line. Placing the conductors closer together has practical limits, however. The distance between the conductors must be sufficient to maintain adequate electric code clearance at all times, and to assure utility employees' safety when working on energized lines. One drawback of a close conductor installation is the need for more support structures per mile (to reduce conductor sway in the wind and sag at mid-span); in turn, costs increase, and so do visual impacts.

Conductor Configuration

The arrangement of conductors influences MF. Conductors arranged in a flat, horizontal pattern at standard clearances generally have greater MF levels than conductors arranged vertically. This is due to the wider spacing between conductors found typically on H-frame structure designs, and to the closer distance between all three conductors and the ground. For single-circuit lines, a compact triangular configuration, called a "delta configuration", generally offers the lowest MF levels. A vertical configuration may cost more and may have increased visual impact. Where the design goal is to minimize MF levels at a specific location within or beyond the ROW, conductor configurations other than vertical or delta may produce equivalent or lower fields.

Optimum Phasing

Optimum phasing applies in situations where more than one circuit exists in an overhead ROW or in a duct bank installed underground. Electric transmission circuits utilize a three-phase system with each phase carried by one conductor, or a bundle of conductors. Optimum phasing reduces MF through partial cancellation. For a ROW with more than two circuits, the phasing arrangement of the conductors of each circuit can generally be optimized to reduce MF levels under typical conditions. The amount of MF cancellation will also vary depending upon the relative loading of each circuit. For transmission lines on the same ROW, optimizing the phasing of the new line with respect to that of existing lines is usually a low-cost method of reducing MF.

MF levels can be reduced for a single-circuit line by constructing it as a "split-phase" line with twice as many conductors, and arranging the conductors for optimum cancellation. Disadvantages of the split-phase design include higher cost and increased visual impact.

Increased Voltage

MF are proportional to current, so, for example, replacing a 69-kV line with a 138-kV line, which delivers the same power at half the current, will result in lower MF. This could be an expensive mitigation to address MF alone because it would require the replacement of transformers and substation equipment.

Underground Installation

Burying transmission lines in the earth does not, by itself, provide a shield against MF, since magnetic fields, unlike electric fields, can pass through soil. Instead, certain inherent features of an underground design can reduce MF. The closer proximity of the currents in the wires provides some cancellation of MF, but does not eliminate it entirely. Underground transmission lines are typically three to five feet below ground, a near distance to anyone passing above them, and MF can be quite high directly over the line. MF on either side of an underground line, however, decreases more rapidly with increased distance than the MF from an overhead line.

The greatest reduction in MF can be achieved by "pipe-type" cable installation. This type of cable has all of the wires installed inside a steel pipe, with a pressurized dielectric fluid inside for electrical insulation and cooling. Low MF is achieved through close proximity of the wires, as described above, and through partial shielding provided by the surrounding steel pipe. While this method to reduce MF is effective, system reliability and the environment can be put at risk if the cable is breached and fluid is released.

Lengthy high-voltage underground transmission lines can be problematic due to the operational limits posed by the inherent design. They also can have significantly greater environmental impacts, although visual impacts associated with overhead lines are eliminated. The Council recognizes the operational and reliability concerns associated with current underground technologies and further understands that engineering research regarding the efficiency of operating underground transmission lines is ongoing. Thus, in any new application, the Council may require updates on the feasibility and reliability of the latest technological developments in underground transmission line design.

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I. Glossary

115-kV: 115 kilovolts or 115,000 volts.

345-kV: 345 kilovolts or 345,000 volts.

Alternating Current (AC): An electric current that reverses its direction of flow periodically. In the United States this occurs 60 times per second (60 cycles, or 60 Hertz.)

ACCC: Aluminum Conductor, Composite Core.

ACCR: Aluminum Conductor, Composite Reinforced.

ACSR: Aluminum Conductor, Steel Reinforced. A common type of overhead conductor made up of many strands of aluminum wire wrapped around a small number of steel wires.

ACSS: Aluminum Conductor, Steel Supported.

Ampere (Amp): A unit of measure for the flow (current) of electricity.

Arrester: A device that protects lines, transformers and equipment from lightning and other voltage surges by safely carrying the charge to ground.

Blackout: A total disruption of the power system, usually involving a substantial or total loss of load and generation over a large region.

Bundle (circuit): Two or more parallel three-conductor circuits joined together to operate as one single circuit.

Bundle (conductor): Two or more phase conductors joined together to operate as a single phase of a circuit.

Cable: A fully insulated conductor usually installed underground. Cables in use nowadays operate mainly at voltages of 69-kV and above.

Capacitance: The ability of conductors separated by dielectric material to store electrical energy in the form of electrically-isolated charges.

Circuit: A system of conductors (three conductors or three bundles of conductors) through which an electrical energy flows between substations. A circuit can be supported above ground by transmission structures or placed underground.

Circuit Breaker: A switch that automatically disconnects power to the circuit in the event of a fault condition. Located in substations. Performs the same function as a circuit breaker in a home.

Conductor: A metallic wire busbar, rod, tube or cable, usually made of copper or aluminum, that serves as a path for electric flow.

Conduit: Pipe, usually made of plastic or steel, for underground power cables. Synonymous with "duct."

Corona: A luminous discharge due to ionization of the air surrounding the conductors, hardware, accessories, or insulators caused by a voltage gradient exceeding a certain critical value. Surface irregularities such as stranding, nicks, scratches, and semiconducting or insulating protrusions are usual corona sites, and weather has a profound influence on the occurrence and characteristics of overhead power-line corona.

Council: Connecticut Siting Council.

DEEP: Connecticut Department of Energy and Environmental Protection. Until 2011, Department of Environmental Protection (DEP).

Delta Configuration: A type of transmission line design in which two of the three conductors are placed on one side of the support structure and one conductor is placed on the other side.

Derating: A reduction in the normal rating of equipment to reflect some condition—for instance, hot weather—that impairs its ability to conduct electricity.

Deadend Structure: A tower strong enough to hold the lateral strain of the conductor in one direction.

Demand: The total amount of electricity required at any given time by an electric supplier's customers.

Dielectric: A material that is a poor conductor of electric current, but an efficient supporter of static electricity. In can support an electrostatic field while dissipating minimal energy in the form of heat. It is frequently used in electrical devices to provide capacitance. Conversely, its use for insulating purposes may provide unwanted capacitance that needs to be mitigated. See Capacitance.

Direct Current (DC): Electricity that flows continuously in one direction.

Disconnect switch: Equipment installed to isolate circuit breakers, transmission lines or other equipment for maintenance or sectionalizing purposes.

Distribution: Line, system. The facilities that transport electrical energy from the transmission system to the customer.

DOE: United States Department of Energy

Duct: Pipe or tubular runway for underground power cables. See Conduit.

Duct Bank: A group of ducts or conduit placed in a trench and encased in concrete.

Dynamic VAR (D-VAR): A voltage regulation system that dynamically regulates voltage levels on power transmission grids and industrial facilities. D-VAR systems detect and almost instantaneously compensate for voltage disturbances by injecting leading or lagging reactive power, measured in VARs (volt ampere reactive).

Electric field: Produced by voltage applied to conductors and equipment. The electric field is expressed in measurement units of volts per meter (V/m) or kilovolts per meter (kV/m); 1 kV/m is equal to 1,000 V/m.

Electric transmission: The facilities (69 kV+) that transport electrical energy from generating plants to distribution substations.

EMF: Electric and magnetic fields.

EPA: United States Environmental Protection Agency

FACTS: Flexible AC Transmission System. A type of electronic device used in combination with other specialized electrical equipment to optimize or stabilize power flow.

Fault: A failure or interruption in an electrical circuit. A short circuit.

FERC: Federal Energy Regulatory Commission.

G: Gauss; 1G = 1,000 mg; the unit of measure for magnetic fields

GIL: Gas-Insulated Transmission Line, using sulfur hexafluoride gas (SF_6).

GIS: Gas insulated substation. A compact type of substation composed of equipment containing sulfur hexafluoride (SF_6) as the insulating medium.

Ground Wire: A conductor, usually located at the very top of transmission structures and parallel to the insulated line conductors, intended to provide the circuit with protection against lightning strikes. Sometimes referred to as a shield wire. In general, any conductor used to bond equipment to the earth (ground).

HDD: Horizontal Directional Drilling. An alternative technique to trenching for the installation of underground cable.

H-frame Structure: A wood or steel structure constructed of two upright poles with a horizontal cross-arm arranged, more or less, in the form of the letter "H."

HPFF: High-Pressure Fluid-Filled. A type of underground cable or cable system where the insulator used is a fluid.

HPGF: High-Pressure Gas-Filled. A type of underground cable or cable system where the insulator used is a gas. Uncommon in the United States.

HTLS: High temperature, low sag conductors.

HVDC: High Voltage Direct Current. Contrasts with HVAC.

Hz: Hertz, a measure of frequency; one cycle/second.

IARC: International Agency for Research on Cancer

Inductance: An electrical characteristic of AC systems, especially prevalent in motors and transformers.

ISO-NE: Independent System Operator New England, Inc. New England's independent system operator.

kcmil: 1,000 circular mills, approximately 0.0008 square inches. A measure of conductor cross-sectional area and used to identify the size of the conductor.

Lattice-type Structure: Transmission or substation structure constructed of lightweight steel members.

Lightning Shield Wire: Electric cable located to prevent lightning from striking transmission circuit conductors.

Load: Amount of power delivered, as required, at any point or points in the system. Load is created by the aggregate load (demand) of customers' equipment (residential, commercial, and industrial).

LiDAR: Light Detection And Ranging. A system commonly used in aerial surveys of transmission lines and ROWs. The equipment consists of a precise navigation system and a scanning laser. The laser transmits light pulses to measure distances to objects. LiDAR has the ability to produce 3-D models of transmission structures with surrounding terrain, and can identify transmission line span length and height at midpoint (sag), and conductor blowout (distance the outermost conductor swings away from the tower).

Line: A series of overhead transmission structures that support one or more circuits; or, in the case of underground construction, a duct bank housing one or more cable circuits.

LTE: Long-Term Emergency rating. Measures the length of time conductors and other electrical equipment can carry the maximum electrical current; typical duration is several hours. See "STE."

Magnetic Field: Produced by the flow of electric currents. Unlike an electric field, a magnetic field is not readily blocked by most materials. The level of a magnetic field is commonly expressed as magnetic flux density in units called gauss (G), or milligauss (mG) where 1 G = 1,000 mG.

Monopole Structure: A type of structure frequently used for transmission lines. Consists of a single column, usually made of steel, with horizontal arms to support insulators and conductors.

MVA: Megavolt-Ampere. One million volt-amperes. A measure of electrical capacity equal to the product of the voltage times the current times the square root of 3. Electrical equipment capacities are sometimes stated in MVA.

MVAR: Megavolt Ampere Reactive. One million volt-amperes reactive. A measure of electrical flow (and sometimes the capacity of electrical equipment) that does no useful work.

MW: Megawatt. One million watts. A measure of useful work done by electricity. Sometimes referred to as "Active Power", in contrast to "Reactive Power" (MVAR).

NEPOOL: New England Power Pool.

NERC: North American Reliability Council.

NESC: National Electrical Safety Code.

NIEHS: National Institute of Environmental Health and Sciences.

NPCC: Northeast Power Coordinating Council.

NPV: Net present value. The difference between the present value of the future cash flows from an investment and the amount of investment. Present value of the expected cash flows is computed by discounting them at the required rate of return.

OH: Overhead. Electric facilities installed aboveground.

Phases: AC circuits are comprised of three phases that have a voltage differential between them.

Porpoising: A term to describe a transmission line that includes several segments of both overhead and underground construction.

Pothead: See Terminator.

Protection/Control Equipment: Devices used to detect faults, transients and other disturbances in the electrical system in the shortest possible time. They are customized or controlled per an entity's operational requirements.

Prudent Avoidance: A policy of action(s) taken at reasonable cost to avoid or minimize effects that may be perceived as undesirable. Specifically, such steps taken to mitigate EMF.

PVC: Polyvinyl chloride; a type of plastic frequently used in ducts.

Reactive Power: The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current lines and equipment owing to their inductive and capacitive characteristics. Reactive power is provided by generators, synchronous condensers, and capacitors, absorbed by reactive loads. It directly influences the electric system voltage. Units of reactive power are often stated in MVAR. See "MVAR."

Rebuild: Replacement of an existing overhead transmission line with new structures and conductors, generally along the same route as the replaced line.

Reconductor: Replacement of existing conductors with new conductors, but with little if any replacement or modification of existing structures.

Reinforcement: Any of a number of approaches to improve the capacity of the transmission system, including rebuild, reconductor, conversion, and bundling methods.

Right-of-way (ROW): Corridor or continuous strip of land where electric infrastructure is located.

SF_6: Sulfur hexafluoride, an insulating gas used in GIS substations and circuit breakers.

Shield Wire: See Lightning Shield Wire.

Shunt Reactor: An electrical reactive power device primarily used to compensate for reactive power demands by high voltage underground transmission cables.

Splice: A device to connect together the ends of bare conductor or insulated cable.

Splice Vault: A buried concrete enclosure where underground cable ends are spliced and cable-sheath bonding and grounding is installed.

Steel Lattice Tower: See Lattice-Type Structure.

Steel Monopole Structure: Transmission structure consisting of a single tubular steel column with horizontal arms to support insulators and conductors.

Step-down Transformer: See Transformer.

Step-up Transformer: See Transformer.

Stormwater Pollution Control Plan: A sediment and erosion control plan that describes all of the construction site operator's activities to prevent stormwater contamination, control sedimentation and erosion, and comply with the requirements of the Clean Water Act.

Substation: A fenced-in yard containing switches, transformers, line-terminal structures, and other equipment enclosures and structures. Voltage adjustments, monitoring of circuits, and other service functions take place in this installation.

Switchgear: General term covering electrical switching and interrupting devices. Device used to close or open, or both, one or more electric circuits.

Terminal Points: The substation or switching station at which a transmission line terminates.

Terminal Structure: Structure typically within a substation that ends a section of transmission line.

Terminator: A flared pot-shaped insulated fitting used to connect underground cables to overhead lines.

Transformer: A device used to transform voltage levels to facilitate the efficient transfer of power from the generating plant to the customer. A step-up transformer increases the voltage while a step-down transformer decreases it.

Transmission Line: For the purposes of Siting Council jurisdiction, any line operating at 69,000 or more volts.

UG: Underground. Electric facilities installed belowground.

Upgrade: See Reinforcement.

USACE: United States Army Corps of Engineers (New England District).

USFWS: United States Fish and Wildlife Service.

VAR: Volt-ampere reactive power. The unit of measure for reactive power. See also MVAR and Reactive Power.

Vault: See Splice Vault.

V/m: Volts per meter, kilovolts per meter: 1,000 V/m = 1 kV/m; electric field measurement

Voltage: A measure of push or force that transmits energy.

Watercourse: Rivers, streams, brooks, waterways, lakes, ponds, marshes, swamps, bogs, and all other bodies of water, natural or artificial, public or private.

Wetland: An area of land consisting of soil that is saturated with moisture, such as a swamp, marsh, or bog.

XLPE: Cross-linked polyethylene (solid dielectric) insulation for transmission cable.