# LIFE-CYCLE 2012 – Connecticut Siting Council Investigation into the Life-cycle Costs of Electric Transmission Lines

**DRAFT REPORT**

**March 16, 2012**

**Prepared for the Connecticut Siting Council**
**By KEMA, Inc.**

Table of Contents

**List of Tables**

**List of Figures:**

# 1. 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. 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. With the assistance of KEMA, the Council prepared this final report. A printed version of the report has been prepared for your convenience.

The life-cycle costs (LCCs) of electric transmission lines include:

- Costs that are incurred to permit, acquire, 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 these costs 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 best information sources on transmission costs are the costs for recently-constructed lines, because the costs of lines built 10 years ago are no longer representative.

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 might vary for future lines with different attributes.

This report is organized in a way that should facilitate its use. In addition to providing quantitative data, it provides useful information about cost elements that vary significantly from one line to another, due to factors such as the terrain along of the right-of-way, the numbers of highway and river crossings, the need to traverse urban and suburban areas, and mitigation of environmental impacts. Chapter 2 introduces the concept of a transmission line's life-cycle cost and discusses its major cost components. Chapter 3 provides first costs for those line types most applicable to Connecticut. Chapter 4 describes in detail some factors that may cause the cost for any specific line to differ from those in Chapter 3. Chapter 5 discusses the cost impacts of different and emerging line technologies. Chapter 6 addresses the major elements of annual operating and maintenance costs and their assumed values for Connecticut transmission lines. Chapter 7 describes transmission losses, which vary in proportion to future regional energy and capacity costs. Chapters 8 and 9 then discuss the electric and magnetic fields (EMF) and environmental impacts that result from transmission lines and the costs of mitigating these impacts, respectively. Finally, Chapter 10 illustrates the calculation of actual transmission line LCCs for a number of typical line types. Appendices follow with some useful reference data.

# 2. 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 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. Net Present Value (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 operating and maintenance costs incurred beyond year twenty-five have very little bearing on the net present value 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 rebuild or upgrade, for example, beyond the 25 year horizon, 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
- Administration and project management

**Operating and Maintenance 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 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. Chapter 10 of this report will give 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 of this report presents the 40-year NPV calculations for each type of transmission line discussed in this report.

As mentioned earlier in this chapter, 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:

- 115 kV overhead transmission lines
- 115 kV underground transmission lines
- 345 kV overhead transmission lines
- 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 Figures 2-1 through 2-4, focus on single-circuit construction types. While the life-cycle costs of some double-circuit overhead lines are presented later in this report, they are used more sparingly in Connecticut, especially where 345 kV lines are concerned, and only for very specific instances where right-of-way may force this design. As stated by Mr. Carberry of CL&P, "ISO planning studies consider that one event would take both circuits out (for a double-circuit line). That gives an advantage to single-circuit lines. So you see less and less use of double-circuit lines on our planning horizon [3]." Therefore, double-circuit lines are not considered "typical" in regards to this report.

## Life-Cycle Costs of Typical Lines

The life-cycle cost calculations include, for the purpose of estimating the cost of energy losses, an energy cost of 10 cents per kilowatt hour. Figures 2.1 through 2.4 offer a basis for understanding the contribution of the basic life-cycle cost elements that are detailed in this report.

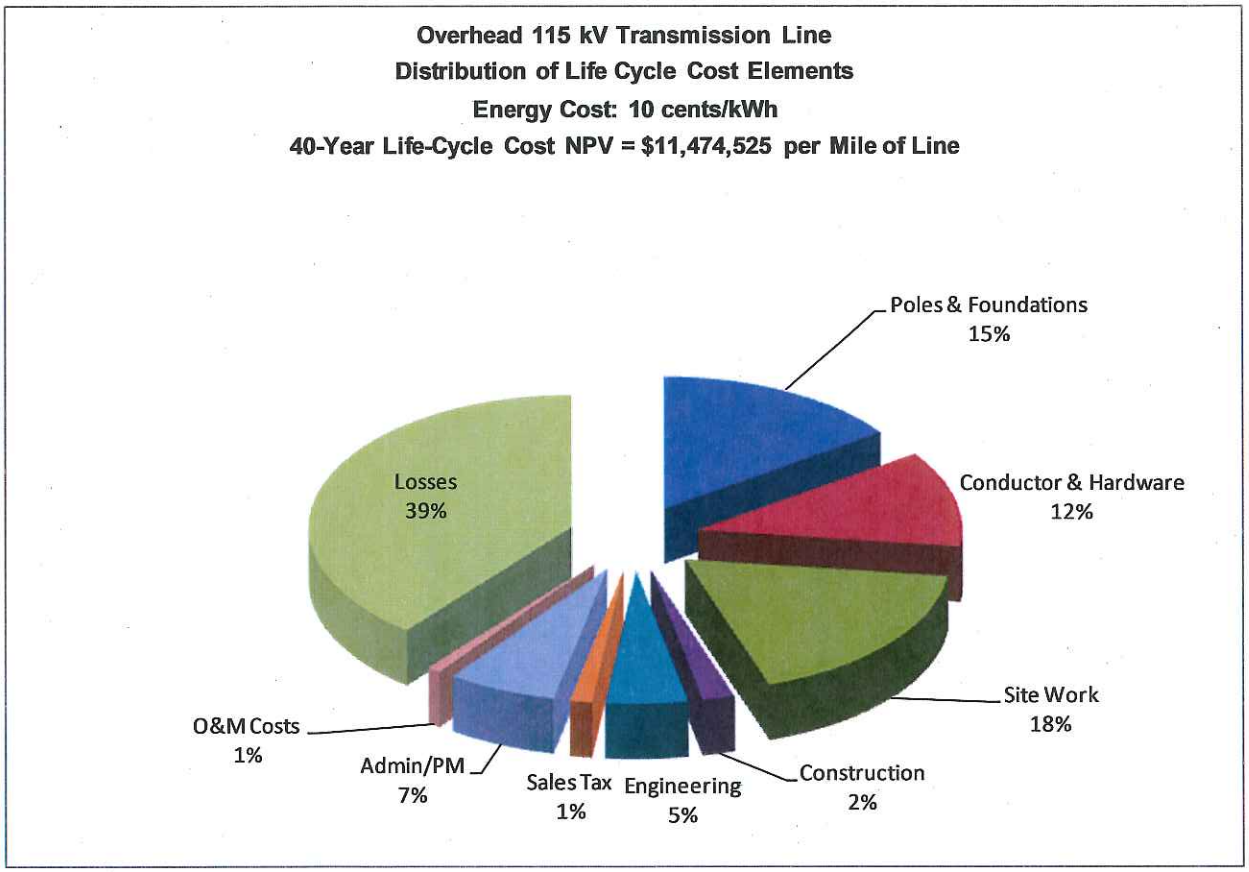


**Figure 2-1: Life-Cycle Cost for a Typical 115 kV Single-Circuit Overhead Line**

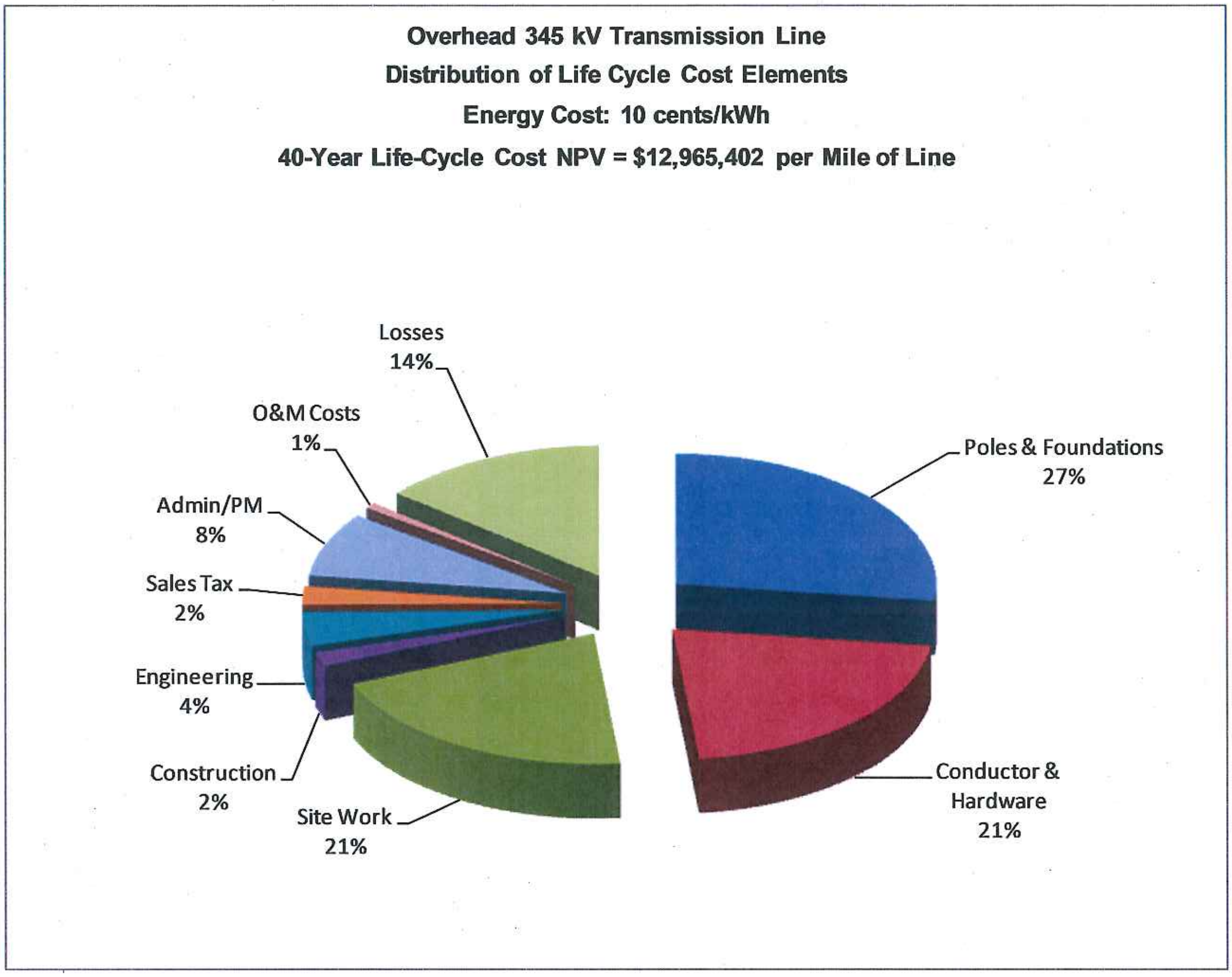


**Figure 2-2: Life-Cycle Cost for a Typical 345 kV Single-Circuit Overhead Line**

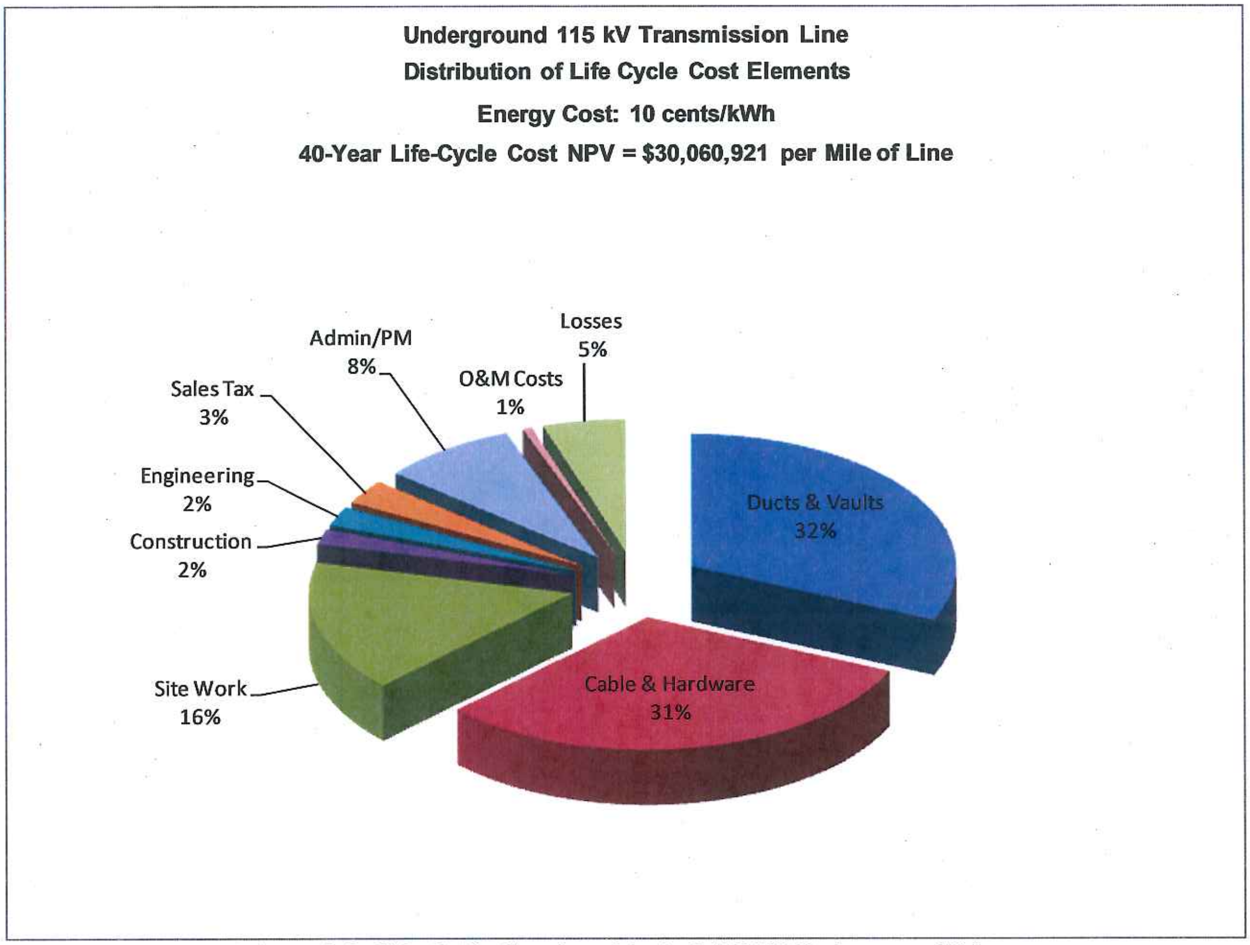


**Figure 2-3: Life-Cycle Cost for a Typical 115 kV Underground Line**

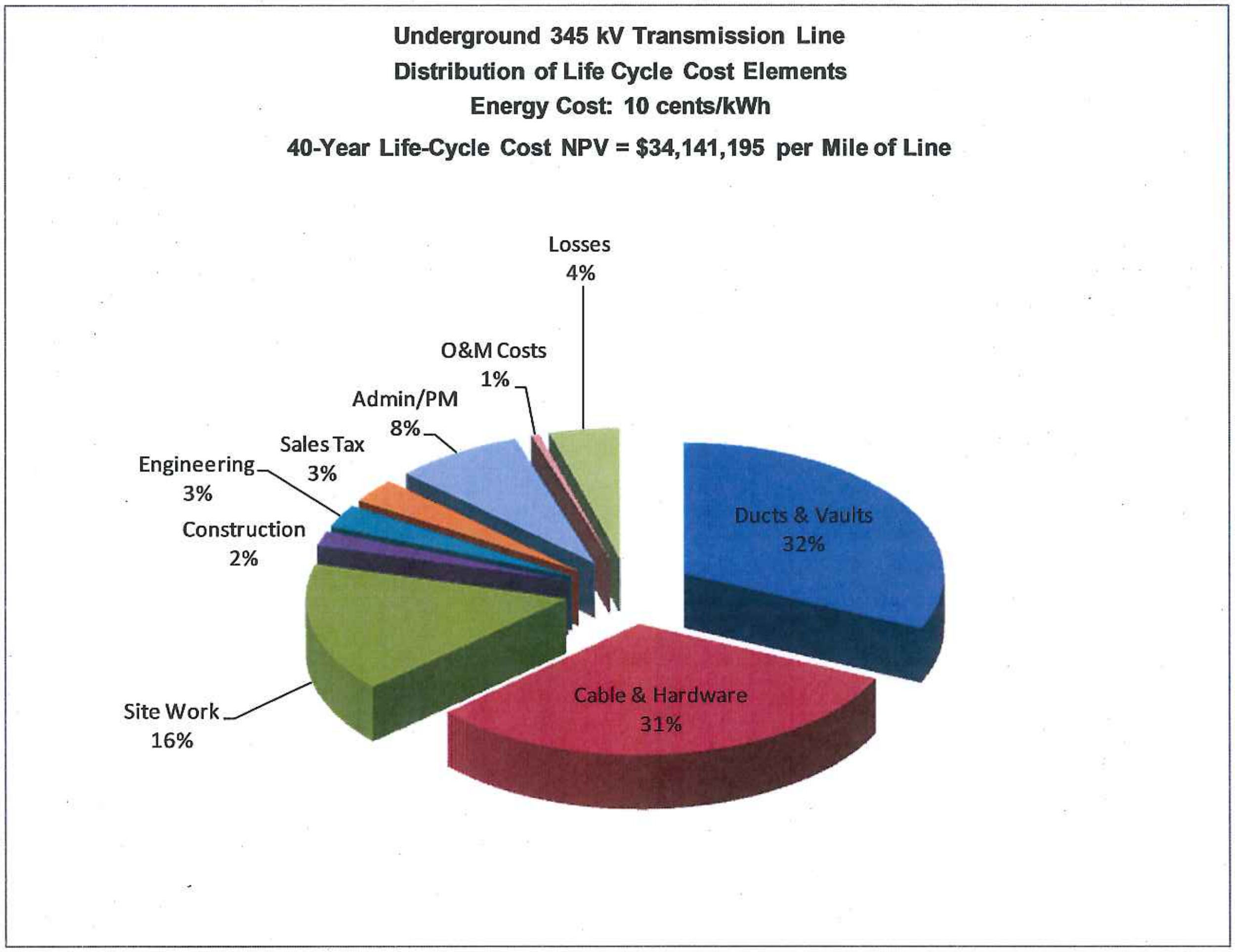


**Figure 2-4: Life-Cycle Cost for a Typical 345 kV Underground Line**

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.

# 3. First Costs of Transmission Lines

## 3.1 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. This report, for the purpose of identifying the first costs of representative transmission lines in the State of Connecticut, 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.

## 3.2 Overhead Transmission

Overhead transmission lines are located above the ground level and are easily seen by the general public. There are different designs of overhead transmission lines that are built to meet different purposes, consistent with the National Electrical Safety Code (NESC). 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. 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 conductors per phase, known as "bundled conductors," the line to 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 not considered likely options for new overhead transmission lines in Connecticut. Therefore, this report addresses the first costs of 115 kV and 345 kV overhead transmission lines. The Council notes, however, that construction of a new 69 kV line could still be an option for some locations where this voltage is still in use and it would be too costly to change.

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 five common transmission line designs that are the most likely to be built in the future. Therefore, this report addresses the first costs of these five designs only. These 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 five designs all employ ACSS conductors. This will be discussed in more detail in Section 5.3. Table 3-1 shows the key characteristics of the five overhead transmission line designs that would likely be considered for future use in the State of Connecticut.

**Table 3-1: 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 |
| 115 | 1272 kcmil ACSS | Steel Poles | Vertical | 2 | A-4 |
| 345 | 1590 kcmil ACSS (bundled) | Wood Pole H-Frame | Horizontal | 1 | A-2 |
| 345 | 1590 kcmil ACSS (bundled) | Steel Poles | Delta | 1 | A-3 |

As shown in Table 3-1, the conductor configurations for overhead transmission lines in Connecticut are Vertical, Delta, and Horizontal. These "names" are common terminology within major utilities and relate to the physical appearance of the transmission line (see drawings in Appendix A).

The major electric utilities in Connecticut identified wood and steel as the primary structural materials for the line designs listed in Table 3.1. 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 3.1 are for single circuit lines only, since double-circuit lines are not representative of "typical" overhead installations, as mentioned in section 2.

Additionally, utilities in the state no longer use wood laminate poles for construction of overhead transmission lines. As Mr. Sickles of CL&P stated, "Laminate wood poles is not one of the present structure types that we use. It would either be wood H-frame or tubular steel construction [2]".

As illustrated by the drawings in Appendix A, the physical appearance of one overhead transmission line design may be quite different from others, even those at the same voltage level. In order to present the full range of first cost information for the overhead transmission line designs listed in Table 3-1, 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:

- 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). (Conductor sizes of 1590-kcmil are assumed. Smaller conductors would typically cost less.)
- Site Work— includes all labor, materials, and expenses incurred in clearing and preparing the land, etc.
- Construction— includes all labor, materials, and expenses incurred during construction including but not limited to foundations, erecting the structures, stringing the conductors, etc.
- Engineering— includes all labor, materials, and expenses incurred in engineering activities.
- Sales Tax (4.6 %)—includes overall taxes in Connecticut
- 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 Chapter 4.

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

**Table 3-2: 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 (4.6 %) | 70,309 | 111,906 |
| Project Management | 556,267 | 362,381 |
| Total Cost/Mile | 3,315,400 | 4,871,000 |

The first costs for double-circuit 115 kV overhead transmission line designs are listed in Table 3-3. These costs are per unit of transmission line length, i.e., USD/mile, and are based on the information provided by CL&P [4] with adjustments by KEMA.

From Table 3-2, we can see that the use of steel poles for single-circuit 115 kV overhead transmission lines has a major impact on the cost of poles and foundations along with site work. The use of steel poles results in a 46% higher total cost per mile when compared with wood poles.

Also, in Table 3-3, first costs for double-circuit 115 kV overhead lines in a vertical configuration using steel poles results in a 38% higher total cost per mile when compared with single-circuit construction.

**Table 3-3: First Costs for Double-Circuit, 115 kV Overhead Transmission Lines**

| **Cost Item** | **Line Design<br>Supporting Structure / Conductor Configuration** |
|---|---|
| | Steel Poles / Vertical |
| Poles/Foundations | 2,312,107 |
| Cable/Hardware | 1,586,986 |
| Site Work | 1,572,621 |
| Construction | 147,947 |
| Engineering | 338,070 |
| Sales Tax (4.6 %) | 186,164 |
| Project Management | 617,504 |
| Total Cost/Mile | 6,761,399 |

The first costs for two 345 kV overhead transmission line designs are listed in Table 3-4. These costs are per unit of transmission line length, i.e., USD/mile, and are based on the information provided by CL&P [3] with adjustments by KEMA. A wood H-Frame structure with horizontal conductor spacing results in a 42% lower total cost per mile when compared with using single steel poles.

**Table 3-4: First Costs for Single Circuit, 345 kV Overhead Transmission Lines**

| **Cost Item** | **Line Design<br>Supporting Structure / Conductor Configuration** | |
|---|---|---|
| | Wood 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 (4.6 %) | 136,411 | 219,721 |
| Project Management | 600,029 | 637,489 |
| Total Cost/Mile | 5,421,200 | 7,714,800 |

## 3.3 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 before 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 which are immersed in thermal sand or lean mix concrete that is 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 seven (7) 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 seven designs only. They are based on two cable technologies: High Pressure Fluid Filled pipe type cable (HPFF), and cross-linked polyethylene cable (XLPE).

Table 3-5 provides characteristics of the seven underground transmission line designs representing those used in the state of Connecticut.

**Table 3-5: Characteristics of Underground Transmission Line Designs used 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-5 |
| 115 | 3000 kcmil XLPE | Horizontal / One cable per phase | 1 | A-6 |
| 115 | 3000 kcmil XLPE DOUBLE-CIRCUIT | Delta / Horizontal / One cable per phase per circuit | 2 | A-8 |
| 345 | 3000 kcmil HPFF | Delta / One cable per phase | 1 | A-5 |
| 345 | 3000 kcmil XLPE | Horizontal / One cable per phase | 1 | A-6 |
| 345 | 3000 kcmil HPFF DOUBLE-CIRCUIT | Delta / Horizontal / One cable per phase per circuit | 2 | A-7 |
| 345 | 3000 kcmil XLPE DOUBLE-CIRCUIT | Delta / Horizontal / One cable per phase per circuit | 2 | A-8 |

As mentioned previously, the cost of land is not included in first costs but is addressed in Chapter 4.

The first costs for 115 kV underground transmission lines are listed in Table 3-6. These costs are per unit of transmission line length, i.e., USD/mile, and are based on the information provided by CP&L [5] with adjustments by KEMA.

**Table 3-6: First Costs for Single-Circuit 115 kV Underground Transmission Lines**

| Cost Item | Line Design<br>Cable Size / Configuration - Cables per Phase | |
|---|---|---|
| | 3000 kcmil HPFF<br>Delta - One cable per phase | 3000 kcmil XLPE<br>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 (4.6 %) | 468,283 | 697,350 |
| Project Management | 1,253,345 | 1,939,134 |
| Total Cost/Mile | 14,970,677 | 21,970,700 |

As can be seen in Table 3-6, for single-circuit 115 kV underground transmission lines, the total XLPE cable system cost is 46% higher per mile than for the HPFF cable system. This contradicts and reverses the findings of the 2007 report. From this, one can conclude that XLPE cable system costs have risen at a much steeper rate than for HPFF cable systems during the past 5 years.

The first costs for single-circuit 345 kVunderground transmission lines are listed in Table 3-7. These costs are per unit of transmission line length, i.e., USD/mile, and are based on the information provided by CL&P [5] with adjustments by KEMA.

**Table 3-7: First Costs for Single-Circuit 345 kV Underground Transmission Lines**

| **Cost Item** | **Line Design**<br>**Cable Size / Configuration - Cables per Phase** | |
|---|---|---|
| | 3000 kcmil HPFF<br>Delta - One cable per phase | 3000 kcmil XLPE<br>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 (4.6 %) | 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 3-7 shows that the total cost per mile of a single-circuit XLPE cable system is 32% 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 3-1).

**Figure 3-1: 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 Chapter 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 Chapter 5.

The first costs for double-circuit underground transmission lines are listed in Table 3-7. These costs are per unit of transmission line length, i.e., USD/mile, and are based on the information provided by CL&P [5] with adjustments by KEMA.

**Table 3-8: First Costs for Double-Circuit Underground Transmission Lines**

| **Cost Item** | **Voltage & Cable Size<br>Conductor Configuration - Cables per Phase** | | |
|---|---|---|---|
| | 115 kV XLPE - 3000 kcmil<br>Horizontal - One cable | 345 kV XLPE - 3000 kcmil<br>Horizontal - One cable | 345 kV HPFF - 3000 kcmil<br>Delta - One cable |
| Duct/Vaults | 9,242,496 | 10,816,640 | 9,084,770 |
| Cable/Hardware | 10,108,980 | 11,830,700 | 7,805,225 |
| Site Work | 4,621,248 | 5,408,320 | 4,606,362 |
| Construction | 577,656 | 676,040 | 511,818 |
| Engineering | 866,484 | 1,691,100 | 639,773 |
| Sales Tax (4.6 %) | 916,740 | 1,072,875 | 800,483 |
| Project Management | 2,549,196 | 2,307,325 | 2,142,470 |
| Total Cost/Mile | 28,882,800 | 33,802,000 | 25,590,901 |

The data in Table 3-7 shows that the total cost per mile of a double-circuit XLPE cable system is also 32% higher than for an equivalent HPFF cable system at 345 kV.

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 Chapter 4.

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. 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, November 15, 2011, Hearing Transcript page 32.
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. 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-004, December 14, 2011.

# 4. Key Factors Affecting First Costs

## 4.1 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 right of way
- 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 Chapter 8 of this report.

## 4.2 Transmission Line Right of Way

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 lines 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.

### 4.2.1 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 terrains;
- 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 for water crossings
- Incremental costs of access road construction in difficult terrains

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 ROWs in Connecticut. Mountainous terrain increase costs by necessitating stronger structures and foundations; also, transmission line length may increase to avoid passing through steep mountainous areas. The different kinds of structures are discussed in the next section of this chapter.

Wetlands are typically environmentally sensitive areas and the transmission line length may increase to avoid passing through this type of terrain. If the transmission line needs to cross wetlands, special foundations are typically required, resulting in higher costs.

Rocky terrains, common in Connecticut, may present particular challenges. 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. Substantially more blasting is required to create the required trench and excavations for splice vaults on an underground route than would be required for the structure foundations on an overhead route [1]. Based on the recent Bethel-Norwalk 345 kV transmission project, more than twenty five percent (25%) of the trench excavation has been in rock. Rock excavation can be almost four times more expensive than soil excavation [2].

Evidence of this cost impact is emphasized by the following response from United Illuminated regarding cost of underground construction: "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% of the total capital costs. As noted by, Graham McTavish, Manager of Transmission Project Planning, for Connecticut Light and Power (CL&P): "We have seen 100-200 % 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].

### 4.2.2 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: private houses, schools, public buildings and parks; rivers and streams; roads and railways; and other infrastructure or utilities. Since these obstacles typically are not spread over a wide geographical area, their impact on costs tend to be small when compared to factors related to 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 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 length may also have to increase to avoid them. If the transmission line needs to cross the rivers or streams, a number of special foundations are typically required.

Wherever an overhead transmission line needs to cross a road, stronger structures and foundations are required. 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].

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 structures and foundations. Thus, cost impacts are very project specific.

### 4.2.3 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 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 are summarized by CL&P, "With the degree of urban and suburban land development that we encounter, especially in Southwest Connecticut, existing transmission line routes take many turns to avoid densely developed areas. Each turn requires more deadend 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]. As stated by Mr.Robert Carberry of CL&P, "In areas where wider right-of-ways are available (rural areas), shorter wood pole H-frame structures can be constructed, but in Connecticut, we are frequently confined to a narrow ROW that can only accommodate vertically-configured lines on taller steel poles [5]."

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.

## 4.3 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. As stated by Mr. Carberry at the Council hearing on November 15, 2011, "Five years ago I don't think there was such a thing (as solutions report). You did a need analysis and examined some options, examined the solutions and went forward with one and prepared to defend why the others were not preferred. The ISO now has a more involved process of studying these various options and you're going to see more and more planning studies to make sure that you've satisfied all federal considerations [14]."

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 Connecticut Siting Council (CSC), the Connecticut Department of Transportation (CDOT), the Department of Energy and Environmental Protection (DEEP), and the US Army Corps of Engineers (USACE).

### 4.3.1 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 a great 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 include:

- 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
- 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 [15]."

### 4.3.2 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 Chapter, 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 onto the road at each vault, the cost of crossing of more buried utilities, and, ultimately, as cable length increases, the cost of additional vaults.

**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, minimum 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 design 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].

### 4.3.3 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 right of way 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. A specific example is given below.

**Contaminated Soil**

Since some of the soil under the local and state roads in Southwest Connecticut may be contaminated, DEEP requires environmental measures whereby the excavated soil cannot be reused to close underground cable trenches and must be stored according to special rules. In the Bethel-Norwalk project, (CSC Docket 217), this resulted in increased disposal and transportation costs.

The degree in which these design changes imposed by CDOT affect costs is very project specific, but generally these issues may cause an increment of 5-10% on the *construction costs* for underground transmission lines [2].

### 4.3.4 U.S. Army Corps of Engineers

The U.S. Army Corps of Engineers (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. This permit, which may take up to a year, is 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.

## 4.4 Land and Land Rights

As mentioned before, the first costs information included in Chapter 3 does 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 the US Department of Energy [4], 5.5% 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 overemphasized. *These costs can be the decisive factor to build a transmission line either underground or overhead.* Referring to land costs, Richard J. Reed, Vice President, United Illuminated (UI), states: "This issue becomes so specific that it can actually change what you're going to build just because of the land costs". As an example for a recent project in Connecticut, Mr. Carberry stated: "In the comparison of the life-cycle costs of overhead and underground 345 kV transmission line alternatives between East Devon (Milford) and Norwalk Substation sites in the recently approved Middletown-Norwalk 345 kV transmission project, the ROW costs were a critical driver of the CL&P initial preference for underground construction over 24 miles of the project route. In this part of the project, there was no available and acceptable overhead ROW, so that overhead construction would have required the expansion of existing rights of way through densely settled suburban areas, at very significant cost, both for the acquisition price and for project delays. On the other hand, there were available highway ROWs that could accommodate underground construction, and the underground route was shorter than an overhead route would have been" [8]. Clearly, a shorter underground transmission line would tend to lower total project cost, but still a cost comparison of the overhead versus underground alternatives reveals that the land costs have significant impact and, in this case, make the underground segment slightly higher than the overhead, as shown below:

- All underground construction for Segment 3 and 4, HPFF cable
  $539 Million
- Nearly all overhead (Alternative B)
  $520 Million

The Council's Finding of Fact estimated a range of life-cycle costs as follows:

- 24 miles of underground construction
  $713-871 Million
- Nearly all overhead (Alternative B)
  $549-631 Million

The costs associated with land and land rights are both highly variable and very project specific. As stated by Mr. Carberry of CL&P, "if a new right of way or expansion of an existing right of way is required for overhead construction through a densely populated area, the cost thereof can be the single largest component of overall capital costs. New ROW costs through rural areas are less significant [4]."

Richard J. Reed states: "I just would never feel comfortable assuming an average land cost because it just differs so much and it differs on where you're going to build it." 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, where as 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 two and a half million a mile. Comparing this $2.5 million per mile with the other capital costs for 345 kV overhead transmission lines identified in Chapter 3, 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 Duct/Vaults, Cable/Hardware, and Site Work.

## 4.5 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 [8].

There are significant differences in the amount of materials and labor required to build an overhead vs. underground transmission line. Underground construction requires significantly higher material costs as a percentage of total project cost than overhead construction, as shown in Table 4-1.

**Table 4-1: Percentage Shares of Total Cost for Labor and Materials, 2007 and 2012**

| Cost Category | 2007 Report | | 2012 Report | |
|---|---|---|---|---|
| | Overhead Transmission Line | Underground Transmission Line | Overhead Transmission Line | Underground Transmission Line |
| Labor | 35% | 24% | 45% | 31% |
| Materials | 65% | 76% | 55% | 69% |
| Total | 100 % | 100 % | 100 % | 100 % |

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

## 4.6 References


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13. 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, November 15, 2011, Hearing Transcript page 32.
14. 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, November 15, 2011, Hearing Transcript page 44.
15. 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.

# 5. 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.

## 5.1 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).

Underground lines have a higher capacitance than overhead lines due to the closer spacing of the conductors. When a line is energized, the capacitance can cause the line voltage to rise above acceptable limits and therefore must be controlled or cancelled. If the load on the circuit is not capable of absorbing the reactive power resulting from the high capacitance of the underground cables, shunt reactors must be installed to compensate for the excess reactive power. While this is a normal operating characteristic of an underground line, it does result in additional costs to a project.

Shunt reactors, when needed in underground circuits, are installed at the terminal facilities where overhead/underground transitions are made. Because this equipment is physically located in a transition station, it is not technically considered to be part of the transmission line itself. However, because it is the line design that 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.

A specific recent example in Connecticut of increased line cost for Hybrid lines is the twenty-four mile extension of underground transmission as part of the 345 kV Middletown to Norwalk project. The additional underground cable resulted in higher transient voltages throughout the Connecticut transmission system. The higher transient voltages resulted in the need to replace hundreds of surge arresters and also required the use of more expensive 500 kV-class equipment at various substations instead of equipment rated for 345 kV.

In the case of hybrid lines, all of the above issues may be involved as both the overhead and underground sections of the line may require additional equipment to compensate for the unique operating issues created by the hybrid line. Other considerations of hybrid lines include the effect of fault currents on the circuit. The cables in underground lines have lower impedance than the bare conductors in overhead lines, and therefore are susceptible to higher fault currents. This could potentially damage the cable and may require mitigation in system design, such as the installation of a series reactor to reduce fault currents or use of higher rated circuit breakers.

## 5.2 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 as a result of the above and below surface nature of the line, similar to a porpoise swimming 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. The consequence however is the excessive cost that would be incurred to build a line underground, for example, across a granite mountain range. Therefore, a hybrid line is sometimes the most feasible option for line construction at a reasonable cost.

As stated by Mr. Carberry of CL&P, "We are required by law to look at locations along the right-of-way where a public or private school, residential area, or day care facility might be adjacent and give an underground alternative. The end result, if the Council ordered us, would be a hybrid line [2]."

Hybrid lines require additional equipment and facilities as compared to fully overhead or fully underground lines. 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 hybrid line, however, may require terminal facilities at each point where the line changes from overhead to underground and again to overhead. At a minimum, a hybrid line would require underground termination facilities within existing stations along the route of a line. 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 terminal facilities required for overhead/underground transitions. These facilities are generally referred to as "transition stations."

Transition stations 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 Chapter 4 of this report. Figure 5.1 shows an example of a typical transition station.

**Figure 5-1: Archers Lane 345-kV Transition Station (Under Construction)**

To illustrate the variability of project costs for overhead, underground and hybrid lines, Table 5.1 provides information on project estimates originally created for the Bethel to Norwalk line, proposed by CL&P in 2003. This example shows that costs for this typical transmission line vary by as much as $60 million depending upon line configuration and technology employed. Note that the most expensive alternative was a hybrid line, as opposed to fully overhead or fully underground. In that option, $20 - $25 million of the additional cost was for the transition stations and shunt reactors required due to the hybrid design [3].

**Table 5-1: Bethel to Norwalk Transmission Line Alternatives**
**(all costs in 2003 dollars)**

**Option 1 - Overhead**

| | |
|---|---|
| **345/115-kV All Overhead** | |
| 345/115-kV overhead transmission line | $ 54,500,000 |
| Right-of-Way acquisition | $ 33,700,000 |
| Substations (Plumtree and Norwalk) | $ 41,700,000 |
| Total | **$129,900,000** |

**Option 2 - Overhead & Underground**

| | |
|---|---|
| **345-kV Overhead /115-kV Underground** | |
| 345-kV/ overhead transmission line and 115-kV from Norwalk Jct. to Norwalk | $ 43,200,000 |
| Right-of-Way acquisition | $ 39,800,000 |
| 115-kV underground transmission line | $ 66,000,000 |
| Substations (Plumtree and Norwalk) | $ 41,500,000 |
| Total | **$190,500,000** |

**Option 3 - Underground**

| | |
|---|---|
| **345-kV Underground** | |
| 345-kV underground transmission line | $136,800,000 |
| Substations (Plumtree and Norwalk) | $ 48,500,000 |
| Total | **$185,300,000** |

**Source: CSC Docket 217 Findings of Fact**

Since the last report in 2007, completion of the Middletown-Norwalk 345 kV "hybrid" line provides an after-the-fact comparison of transmission line first costs. The total project cost was $1.27 billion for a 69-mile line (24 miles underground, 45 miles overhead, with several transition stations). Assuming the ratio of overhead-to-underground miles is typical for a hybrid line, the average cost of a hybrid 345 kV line is $18.4 million per mile (in 2010 dollars), compared to $5.4 to 7.7 million per mile for overhead 345 kV and $16.6 to 21.9 million per mile for underground 345 kV [4, 5, 6]. This further illustrates the point that hybrid lines are the most expensive option.

## 5.3 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 higher throughput of energy. These technologies are being used in both retrofit applications to existing lines as well as initial design elements of new lines. These technologies are in the areas of materials and systems devices and include Flexible Alternating Current Transmission Systems (FACTS), High Voltage Direct Current transmission (HVDC), and HTLS (High Temperature, Low Sag) composite conductors. Each has benefits in certain line applications and represents additional tools and methods for future use to increase transmission capacity.

## 5.3.1 FACTS and Typical Costs

Flexible AC Transmission Systems (FACTS) incorporate electronic-based controllers with other static controllers 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 5-2.

**Table 5-2: 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 |

Only an SVC or STATCOM would have a direct application in Connecticut. According to Mr. Carberry of CL&P, "to narrow the list of devices that are applicable to New England situations, STATCOMS or SVCs belong on the list [3]." CL&P currently has one FACTS device on their system, a fully-redundant 75 MVAR STATCOM device (150 MVAR total) located at the Glenbrook Substation. This device is the only one in the State and was installed in 2004 at a cost of $15.6 million [13]. 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 (SVC, STATCOM, SSSC) for larger transmission based projects (i.e., capacities of 200 MVAR and higher), which 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, and 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 5-2.

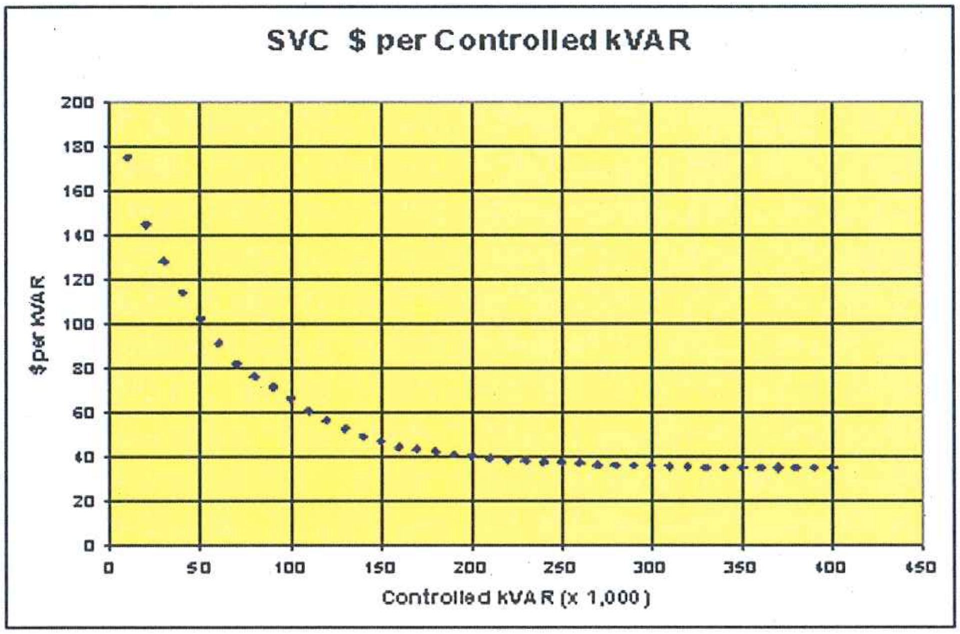



**Figure 5-2: SVC System Cost vs. Size (Controlled kVAR)**
**Source: Electric Power Initiative White Paper on Power Electronics Technologies [12]**

Advanced STATOM (Voltage-Sourced Converter) system costs are about 20% 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% less than what is required to meet the same performance as a conventional SVC [12].

## 5.3.2 HVDC Typical Costs

High voltage direct current 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 injected where needed
- Higher power over the same right of way, thus fewer lines
- Bypassing congested circuits – no inadvertent flow

- Requires only two instead of three conductor sets
- No distance stability limitation
- Reactive power demand limited to terminals
- Fewer losses over long distances

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, create the possibility for HVDC to be cost competitive and operationally preferred to an AC circuit. The Cross Sound cable is an example. The high cost of terminal converter stations required for HVDC often offset any potential savings compared to an AC line. As an example, option "E" of the Interstate Reliability Project report provides a cost estimate of $536 million (in 2008 dollars) for the two 1,200 MW converter stations that would be required, one for each end of the 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. That alternative was "the first option eliminated because it offered fewer system benefits than most AC options at a greater cost [7]."

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.

### 5.3.3 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, also known as HTLS (high-temperature, low-sag) 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 use of composite conductors as compared to steel core conductors include:

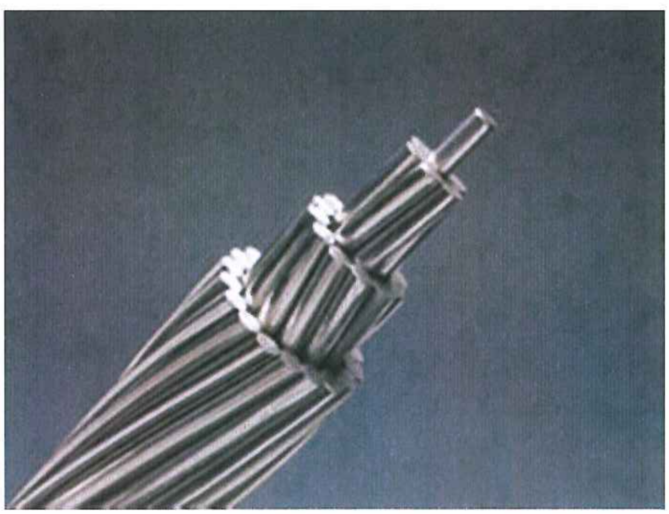
- Higher current-carrying capacity and operating temperature.
- Higher strength-to-weight ratio.
- Less conductor sag at a given load.
- Because of lighter weight and less sag, composite conductors allow greater line capacity without the need for taller transmission structures.

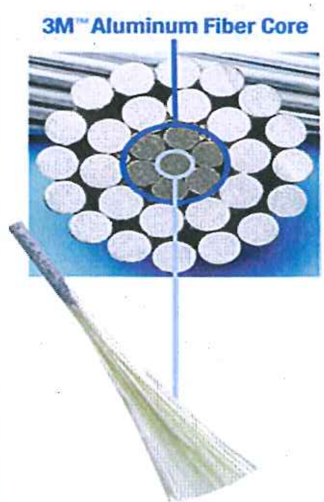
There are several types of composite conductors available for use in transmission line construction today. The acronyms for these conductors are defined in Table 5-3.

**Table 5-3: Composite Conductor Definitions**

| Conductor Definitions | |
|---|---|
| **Type** | **Description** |
| ACSR | Aluminum Conductor, Steel Reinforced |
| ACSS | Aluminum Conductor, Steel Supported |
| ACCR | Aluminum Conductor, Composite Reinforced |
| ACCC | Aluminum Conductor, Composite Core |

ACCR conductor was developed by the 3M Corporation along with the U.S. Department of Energy (DOE) with the goal of creating a conductor that can carry more current with less sag. To accomplish this, ACCR conductor utilizes aluminum-oxide core strands and composite fibers as the strengthening material to form a fiber-reinforced metal matrix. Cross-sectional views of an ACSS conductor (on the left) and an ACCR conductor (on the right) are shown in Figure 5-3.

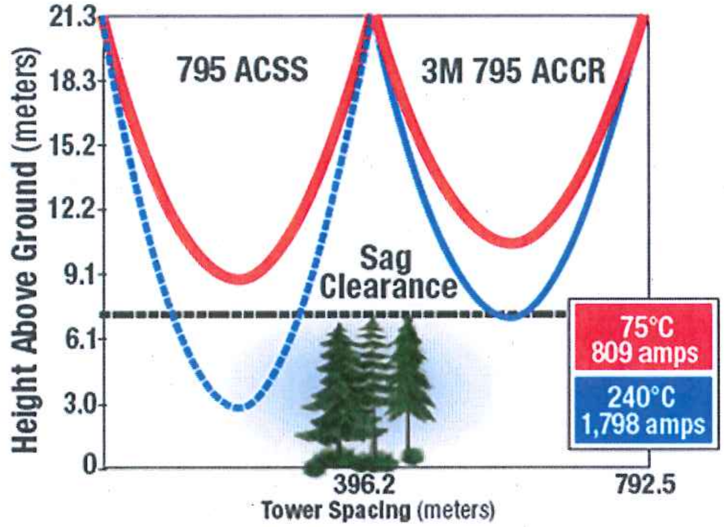





**Source: Alcan Products Catalog** **Source: 3M Corporation**

**Figure 5-3: Cross-sectional view of an ACSS HTLS conductor and an ACCR composite conductor**

An illustration of reduced conductor sag using HTLS conductor is shown in Figure 5-4.




**Source: 3M Corporation**

**Figure 5-4: Illustration of reduced sag and increased clearances using composite conductors**

CL&P has adopted Aluminum Conductor, Steel Supported (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 temperature, 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 [8].

UI remains committed to the continued use of ACSR as their standard conductor for overhead transmission lines. In response to inquiries about the use of composite conductors such as ACCR or ACCC conductors on their system, UI stated: "Conductor material costs for ACCR are roughly 5 times the cost of ACSR. The Company has not actively pursued information regarding the cost of ACCC conductors [9]." However, UI also stated that they "may consider the use of composite conductors for its future re-conductoring projects [10]". 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 [11]. Therefore, all transmission line first costs used in this report are based on data provided by CL&P.

Table 5-4 shows a cost comparison between Aluminum Conductor, Steel Reinforced (ACSR) and the 3 alternative composite conductors defined in Table 5-4. This comparison is based on conductor price only and does not include special hardware, fittings, or installation.

**Table 5-4: Conductor Cost Comparisons**

| Conductor Price Comparison | | | |
|---|---|---|---|
| Concuctor 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 10.2 comparing ACSR and ACSS conductors.

### 5.3.4 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 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. An example of the new Triax superconducting cable is shown in Figure 5-5.

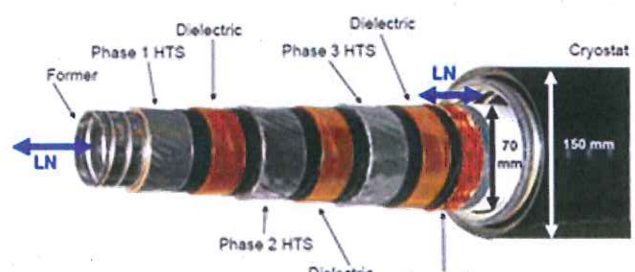



**Figure 5-5: Triax Superconducting Cable**
**Source: Superconductivity News Update**

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. There are currently no superconducting cables operating in or planned for the state of Connecticut because of the cost and current level of technology.

## 5.3.5 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 10, there is a presentation of the cost impact of alternative conductors in transmission life-cycle cost analysis, by comparing ACSR and ACSS conductors.

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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, November 15, 2011, Hearing Transcript, page 54.
3. Connecticut Siting Council, RE: Life-Cycle 2011, Investigation into the Life-Cycle Costs of Electric Transmission Lines, January 12, 2006, Hearing Transcript, page 51.
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-002, December 14, 2011.
5. 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.

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 3, Q-CSC-004, December 14, 2011.
7. Solution Report for the Greater Springfield Reliability Project, August 2008.
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 2, Q-CSC-017, October 21, 2011.
9. 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.
10. 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-010.
11. 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-002 and OCC-004.
12. Reed, Gregory; University of Pittsburgh, Swanson School of Engineering; "Electric Power Initiative White Paper on Power Electronics Technologies (draft)," January, 2012.
13. 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.

# 6. Operating and Maintenance Costs

## 6.1 General

After a transmission line is constructed and energized, there are many tasks that must be performed on either an on-going periodic basis, or on an as-needed conditional basis, 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:

- Reliable supply of power to customers, and
- Production of power in the most economic way possible

These two goals must be achieved while adhering to requirements for safe and reliable operation. This includes such things as ensuring that all system components operate within their thermal ratings; that system voltages remain within acceptable limits and that all generators connected to the system operate in synchronism. These operating requirements must be met in a dynamic environment. The electric system is continuously exposed to disturbances of varying severity, including short-circuits, failure of transmission line components, or failure of generating units. Transmission operating limits must be properly adjusted to provide for these contingencies. 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 conditions as described, normal operating environment changes such as load fluctuations due to weather, time of day, or off system demand for power purchases create a continuously changing environment that must be monitored and managed by operations personnel. Weather condition changes for example, can bring about sudden changes in the load or outages. Fast moving cold or warm fronts can result in lightning or storms with high winds that may cause sharply increased loads and/or widespread outages. 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 four classes:

- Those associated with the operation of equipment;
- Those associated with the technical control of the transmission system and with administrative transactions costs;
- Those that are incurred as a result of constraints on the operation of the power transmission system; and
- Those associated with losses (see Chapter 7 for more information)

Specific operating costs include the labor costs and expense items required to execute the activities required to meet the operational requirements associated with transmission lines. These activities may include such tasks as 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 tests of circuits; and various inspection and analysis activities associated with line operations. In addition to these tasks, there are many administrative requirements on system operations personnel to create and maintain 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. There are also significant non-routine activities that are unplanned, such as line overloads, generating unit or major transmission forced outages, or storm conditions. These activities can be very costly, and can account for large overruns of budgeted expenditures. In addition to large amounts of time and costs associated with switching and coordination of system recovery, special studies must then be performed for the new system conditions.

## 6.3 Maintenance Costs

In addition to operating activities, proper line maintenance is required to achieve optimum levels of service reliability. A highly reliable transmission line is based on many factors that begin 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 many elements, beginning with field inspection, repair, and eventual 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. Increases in vegetation management costs have impacted life-cycle O&M costs due to:

- More patrols on 345 kV circuits which are 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 3 times per year.
- 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 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 3 years. These surveys are limited to 345 kV lines.
- Increased inspections for high-risk trees off the ROW that could fall into the transmission line.
- Increased efforts to remove tall growing red cedar trees within areas under lines that are subject to NERC TVM Standard FAC-003-1.

These programs have increased annual transmission line O&M costs and were 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 right-of-way on which the line is constructed.

Routine maintenance activities include such things as:

- 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.
- LiDAR helicopter surveys to identify vegetation clearance issues along the ROW.
- 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

Overhead Transmission Line Maintenance Costs in the state of Connecticut have been steadily growing over the past 5 years, with major increases in the last 2 years, as shown in Figure 6-1.

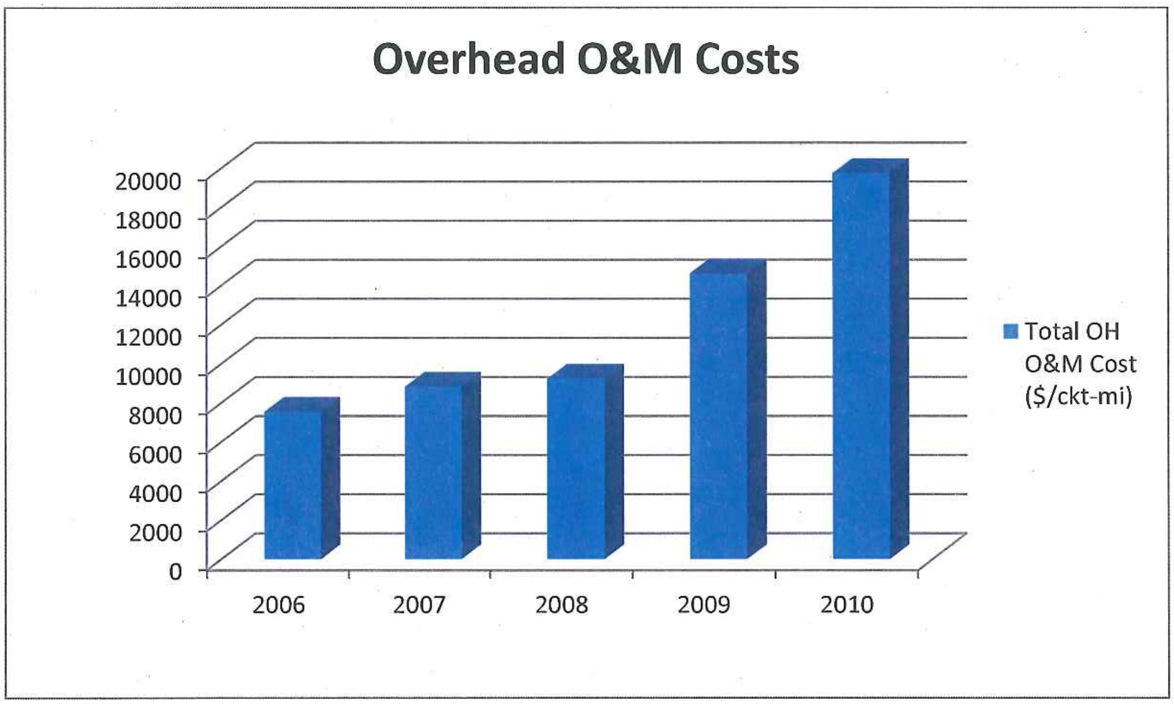



**Figure 6-1: Total Overhead Transmission Line O&M Costs, 2006-2010**

These O&M cost increases are primarily the result of complying with NERC VM Standard FAC-003-1 and implementation of LiDAR patrols, which will be discussed further later in this section.

**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:

- Mowing the right-of-way
- Side-trimming trees along the edge of the right-of-way
- Removal of trees within the right-of-way
- Removal of trees that are outside the limits of the right-of-way but due to their size and condition represent a high risk of falling into the transmission line
- LiDAR aerial patrols of the right-of-way

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 6-2.

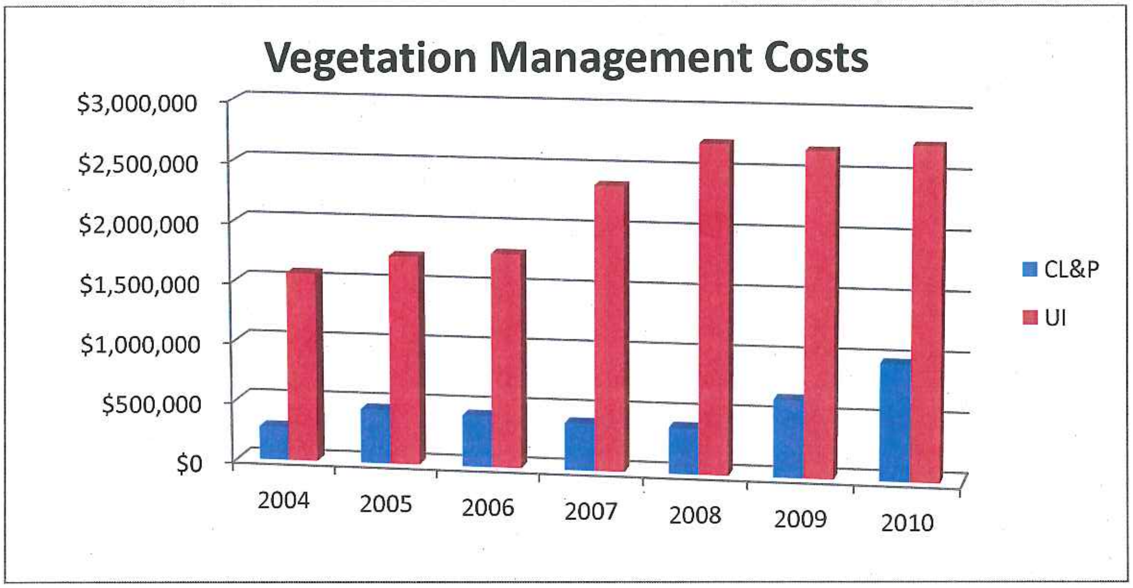



**Figure 6-2: Transmission Vegetation Management Plan Costs, 2004-2010**

More patrols now occur on 345 kV transmission circuits, which are regulated under the North American Electric Reliability Corporation (NERC) Transmission Vegetation Management Standard FAC-003-1. Previously, these lines were patrolled once per year, and this frequency has now been changed to 3 patrols per year as a result of the new VM standard.

**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 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:

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

Danger trees such and the one illustrated in Figure 6-3 can be easily and quickly identified with the use LiDAR surveys and targeted for removal.

**Figure 6-3: Danger Tree in transmission ROW**

LiDAR can provide a 3-D image of the transmission ROW with color-coding used to indicate elevation, as shown in Figure 6-4.

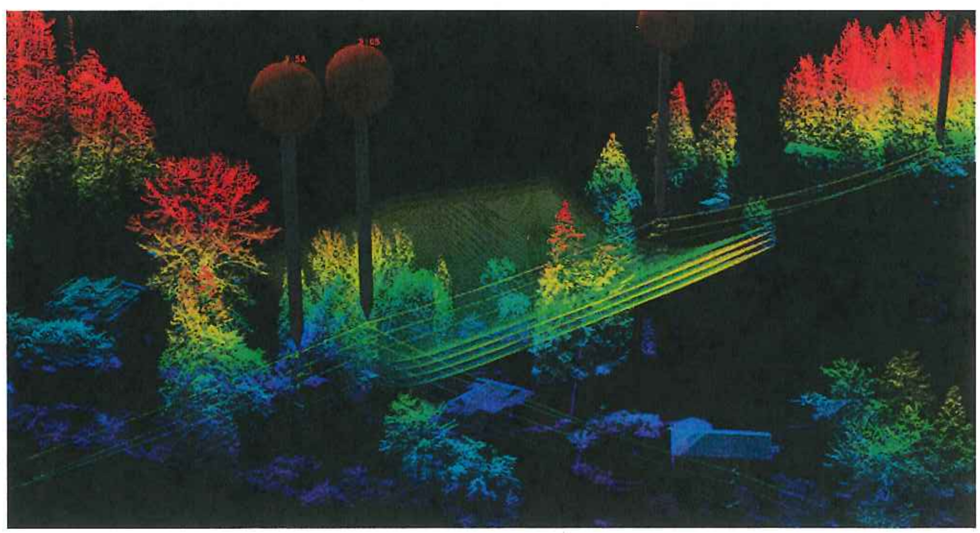


**Figure 6-4: LiDAR 3-D image of transmission ROW**

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 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].

Many companies also use herbicide treatments on rights of way to inhibit the growth of fast growing species of grasses, weeds and trees. Utilities in the state of Connecticut, however, do not use herbicides or growth retardants [1, 2, 6, and 7].

### 6.3.2 Underground transmission line maintenance

Even though some transmission lines are located underground, there is still a considerable amount of routine maintenance that 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 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 include 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; repairs to sewers and drains, walls and floors, rings and covers; re-fireproofing of cables and repairing supports; and repairing or moving boxes and potheads.

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

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 6-5.

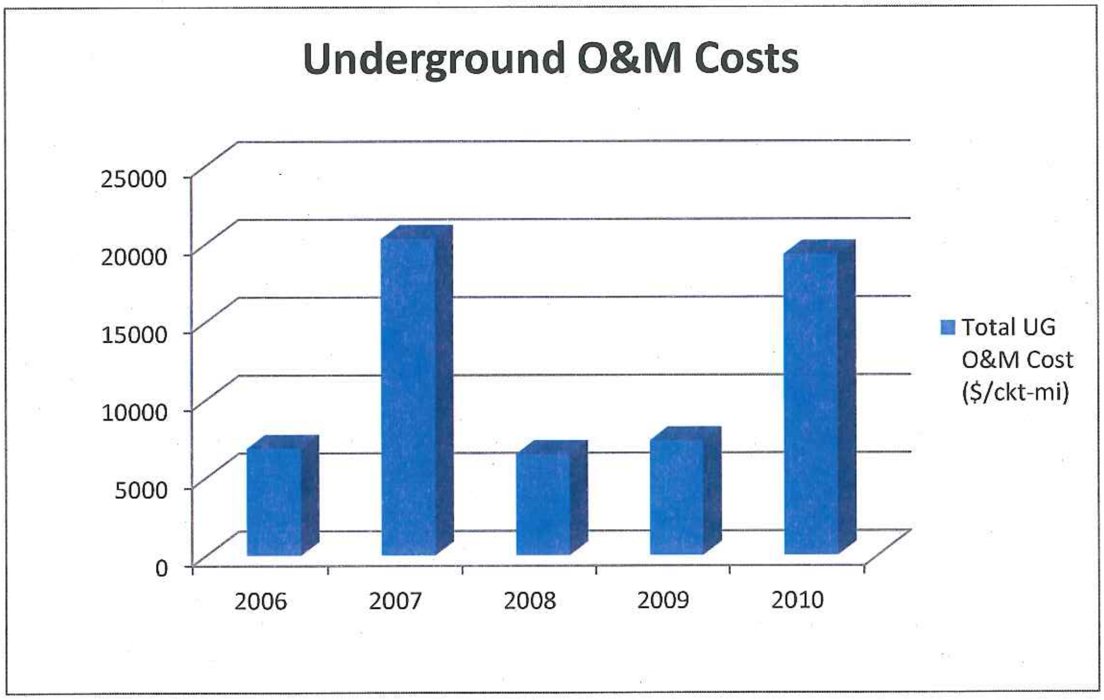



**Figure 6-5: Total Underground Transmission Line O&M Costs, 2006-2010**

The major increases in underground maintenance expenditures have occurred as a result of major cable repairs in 2007 and 2009 [8]. The amounts shown in Figure 6-5 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 also likely increase in frequency with age, including insulator washing, pole treatment, pole and guy adjustments, and ground maintenance.

- Weather impacts – a huge impact on costs incurred 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 those comparing these results among utilities. Among these vagaries are treatment of line terminal equipment, joint use land, conduits and poles between transmission and distribution, unit of property designations, 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.

Figure 6-5 shows the erratic nature of underground transmission O&M costs. There can be years when there are no 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 typical O&M costs and 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, the 2010 O&M data was more heavily weighted for establishing a basis for transmission O&M costs.

## 6.5 O&M Cost Assumptions for LCC 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 the Federal Energy Regulatory Commission (FERC). Three of these are operations accounts, including:

- Account 560 – Operation Supervision and Engineering
- Account 563 – OH Lines Expenses
- Account 564 – UG Lines Expenses

There also are three maintenance accounts, including:

- Account 568 – Maintenance Supervision and Engineering
- Account 571 – Maintenance of OH Lines
- Account 572 – Maintenance of UG Lines

Connecticut transmission line O&M costs were taken from the information provided by UI and CL&P in response to the Council Interrogatories. The average of the $/circuit-mile values for 2010 were used as the base year values for life-cycle cost analyses of overhead lines. The average of several recent years of data would be more representative of an average value than any one year of data for determining typical O&M costs. However, with the implementation of new Transmission Vegetation Manage Plans to meet NERC FAC-003-1 in 2007 and LiDAR airborne patrols beginning in 2009, the 2010 data provides a better basis for establishing overhead maintenance costs, which have grown in the last year. The O&M costs for 2010 are higher than any other previous years for these reasons, but accurately reflect the additional cost of the new TVMPs that would not be captured in previous years of cost data. Cost escalation was assumed to be 4% per year for all O&M cost projections.

For analyses involving underground lines, it was noted that a significant and infrequently occurring maintenance event can distort maintenance costs in any given year, particularly for underground transmission line assets with a small number of 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 data was used as a basis for establishing underground maintenance costs.

There have been major improvements and cost increases associated with TVMPs, line patrols, LiDAR surveys, and "special" tree-trimming standards. An average over several years would not capture these improvements and their associated cost increases. Therefore, 2010 was used as the benchmark for establishing a basis for overhead transmission O&M costs. The actual O&M costs 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 |
| **Operation** | | |
| 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 United Illuminating, 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 United Illuminating, only 50% of the total of Account 568 – Maintenance Supervision and Engineering, was allocated to Transmission Maintenance Expense. Of that amount, 97% was allocated to overhead maintenance, and 3% 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, shown in Table 6-2.

Table 6-2: Average Underground O&M Cost, 2009-2010

| Cost Category | UI | CL&P |
|---|---|---|
| 2010 UG O&M w/out 560 & 568 | $59,702 | $1,556,160 |
| 2010 UG O&M with 560 & 568 | $196,982 | $1,672,080 |
| % Difference (Scaling Factor) | 330% | 107% |
| 2009 UG O&M ($/ckt-mi) | $1,554 | $5,804 |
| Total Circuit Miles [1] | 28.45 | 135 |
| 2009 UG O&M Costs ($) | $44,211 | $783,478 |
| Scaled 2009 O&M Costs ($) | $145,872 | $841,840 |
| Scaled 2009 UG O&M ($/ckt-mi) | $6,043 | |
| 2010 UG O&M Costs ($/ckt-mi) | $11,435 | |
| **2009/2010 Average ($/ckt-mi)** | **$8,739** | |

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 calculations detailed in Chapter 10, and they are recommended for use in future analyses until updated by the Connecticut Siting Council.

It is worth noting that without including FERC Accounts 560 and 568 that relate to O&M Supervision and Engineering, the average values for transmission line O&M in $/circuit-mile would be $4,332 for overhead and $9,883 for underground. The difference is particularly striking for United Illuminating, and would result in $12,434/circuit-mile for overhead transmission O&M and $2,095/circuit-mile for underground O&M. Adding Account 560 and 568 expenses that relate to underground transmission line maintenance results in a figure that is 3 times the total cost per circuit mile if these costs are not included. The 2010 underground O&M cost components for UI are shown in Figure 6-6.

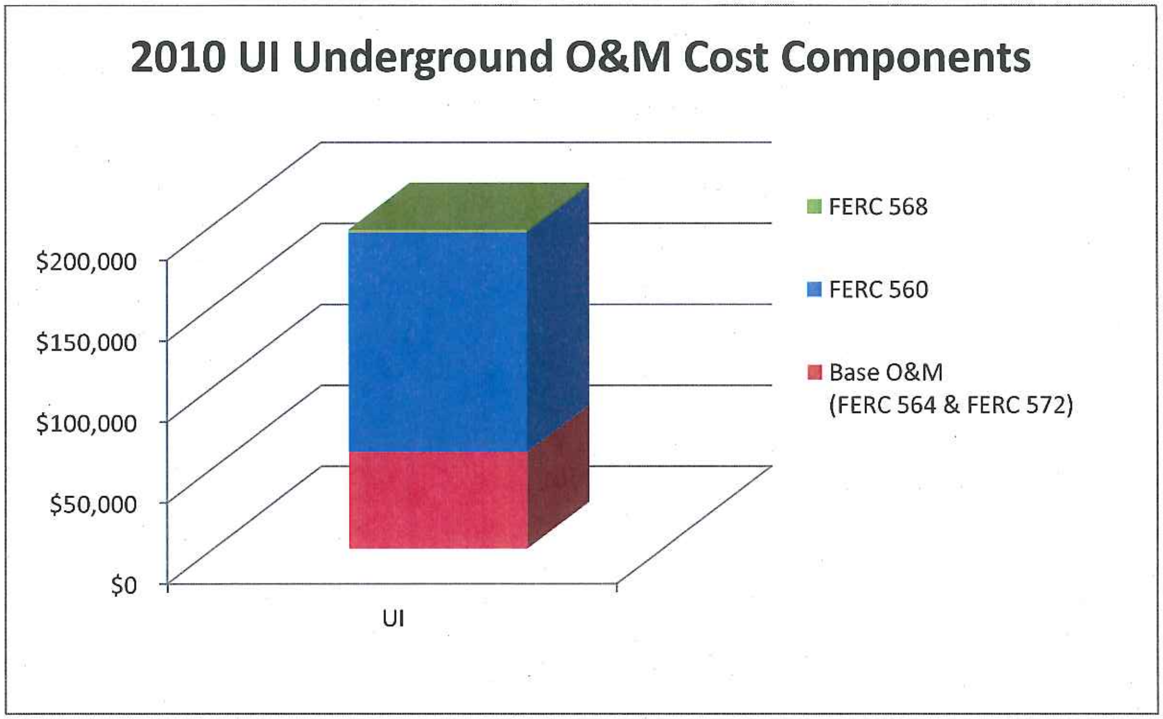



**Figure 6-6: Underground 2010 O&M Cost Components for UI**

## 6.6 Cost-effectiveness of O&M Expenditures

It is interesting to note that O&M costs represent only 1% of the total life-cycle cost for every "typical" transmission line construction type shown in Figures 2-1 through 2-4. As described elsewhere in this report, the utilities in the State of Connecticut have recently increased their overhead transmission line maintenance budgets to include more pro-active vegetation management and airborne line patrols. These utilities recognize that there is a direct correlation between line maintenance expenditures and reliability, especially when a storm arrives. The excellent overall level of transmission system reliability achieved by the utilities in the state of Connecticut while spending only 1% of the transmission life-cycle cost on Operation & Maintenance is a remarkable achievement.

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. 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, CSC-001, December 14, 2011.
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-011.
5. 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 3, Q-CSC-001.
6. 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.
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-013.
8. 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. Transmission Loss Costs

## 7.1 General

Since no device is 100% 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 of the transmission line life-cycle costs may be attributable to the losses incurred during operation of the line. In addition to the magnitude of the load current, there are many factors that affect the impedance value that have a direct bearing on the loss costs.

## 7.2 Types of Losses

There are two fundamental types of resistive losses:

- No-load losses are primarily generated in the steel cores of transformers and other devices with windings. These losses vary with the voltage, not the load, and therefore are typically considered to be of constant value while the component is energized. (Note: These only occur in substations, and are not considered part of the transmission line life-cycle costs) There also will be line insulation losses, more so for underground cables than overhead lines, but these are insignificant by comparison and seldom considered.

- Load losses are present in the windings of transformers and other devices, as well as in transmission lines and cables. 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 line currents increase, the magnitude of load losses can vary greatly between peak load and light load conditions.

The reactive power demands of transmission lines and transformers also cause line currents to increase, contributing further to resistive energy losses. Such losses are generally controlled through the insertion of capacitor banks which can be switched in fixed or variable increments automatically or remotely.

## 7.3 Costs

There are two basic components of the costs of losses.

- Energy costs are associated with the consumption of fuel and related expenses required to generate the energy that is lost. Costs associated with the resulting increase in system losses are also typically included here.

- Capacity, or demand costs are the costs associated with the additional generation and transmission equipment required due to the presence of these losses. This 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 "marginal cost" representing 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 that occurred 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.
- 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.

## 7.4 Contributing Factors to the Cost of Losses

There are several factors that influence the magnitude of the cost of losses in a given transmission line, including:

- Line length – the impedance of the line increases proportionally with the length of the line.
- Conductor type & size – different types of conductors have different resistive and reactive characteristics. The larger the conductor, the lower the resistance.
- Load magnitude – as mentioned above, the load losses 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 the NPV of the cost of losses.

- Generating unit type – energy and demand costs vary widely for various types of generation.
- Voltage level – no-load losses will vary depending on the level of the operating voltage.

## 7.5 Loss Cost Formula

The following formulas are used by KEMA to approximate cost of transmission losses. The loss calculations are based on an example peak load current for a line.

**EC** (Energy Cost) = 3 x R x $I^2$ x 8760 x LF x AIC x LIF, and

**DC** (Demand Cost) = 3 x R x $I^2$ x IDC x LIF

**Where**

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)

LIF = loss increase factor (1 + PU system losses reflecting increase)

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

NOTES: AIC is based on the wholesale price of electricity ($10/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 assumed to be zero [1].

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.

# 8. Cost Effects of EMF Mitigation

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 30 years, because there is concern that these fields may present health risks to those who are exposed to them on a regular basis. However, as stated previously by Acres (1):

> The biological effects from extremely low frequency fields are difficult to detect and define. At the present time, many studies on the subject of health risk and EMF have been conducted worldwide. To date, the scientific evidence is inconclusive, and a direct link between adverse health and EMF associated with electric power frequency (60 Hz in North America) cannot be confirmed or denied.

Despite this lack of proof, standards have been adopted by some governmental agencies as a safeguard for public health. Because there often are additional 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 3. 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.

## 8.1 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 Appendix B.

### 8.1.1 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 8-1 shows the magnetic and electric fields for both horizontal and delta conductor configurations at 345 kV. Magnetic fields for the delta configuration are 64% 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% lower than those for the horizontal configuration, but they are 50% 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 that are approximately 80% higher.

Line voltage also is an important factor in determining EMF levels near an overhead transmission line. Table 8-2 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 8-1 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 8-2 are approximately one-third of those for Table 8-1, 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 1000 Amperes per phase, as was the case for the comparable 345 kV lines, magnetic field levels changed far less between Tables 8-1 and 8-2. Once again, the changes are primarily due to differences in conductor configuration and spacing.

### 8.1.2 Effects of split-phasing

Split-phasing is a line design concept that reduces EMF by canceling the fields using additional phase conductors on the transmission towers. The most typical arrangements use two conductors per phase, for a total of six conductors. However, the towers must be comparable to those required for a double-circuit line, with the associated additional cost. Split phasing, while it utilizes six conductors, is a single-circuit configuration. It should not be confused with reverse-phasing, which involves a double-circuit line.

Table 8-1 (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% higher than those for a single-circuit, wood H-Frame design (R.I. Study). Table 8-2 (part C) shows similar reductions for a split-phasing arrangement at 115 kV.

**Table 8-1: 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 8-2: 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 8-3: 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 |

### 8.1.3 Single vs. Double-Circuit Lines

Table 8-3 lists EMF levels at various distances from the center-line of a single-circuit and a double-circuit 115 kV overhead line. The conductors for each circuit are arranged vertically, and a nominal loading level of 1000 Amperes per phase was assumed for both lines. Even though the power flow is doubled under these loading assumptions, EMF levels for the double-circuit line increase by less than a factor of two. This is due to some cancellation in the fields from the two circuits.

However, this assumes like-phasing of the conductors and like-current directions. If reverse phasing were employed instead, the result would be substantial reductions in EMF levels in comparison with the single-circuit vertical line.

A comparison of EMF levels for the single-circuit line in Table 8-3 that has a vertical conductor configuration with those for the single-circuit line in Table 8-2 that has a delta configuration shows quite similar field levels. Greater EMF level reductions are possible with more compact delta configurations that have less space between the conductors for each phase.

## 8.2 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.

### 8.2.1 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 Figure 8-1 shows, the maximum magnetic field for the assumed 115 kV XLPE line with cables in a horizontal configuration and a loading level of 1000 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

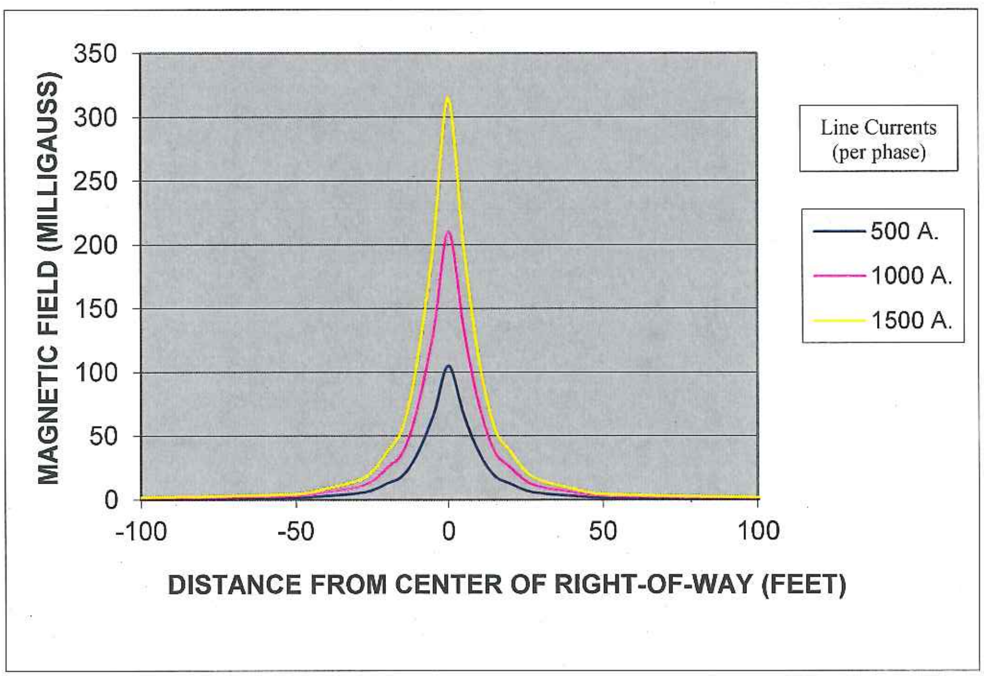



**Figure 8-1: Magnetic Field Profiles for 115 kV XLPE Line with Horizontal Cable Arrangement Source: Connecticut Siting Council and Acres International Corp. [1].**

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 Figure 8-2). Magnetic field levels for three different line loadings are presented in Figures 8-1 and 8-2. Conductor sizes and physical arrangements are shown in Appendix A.

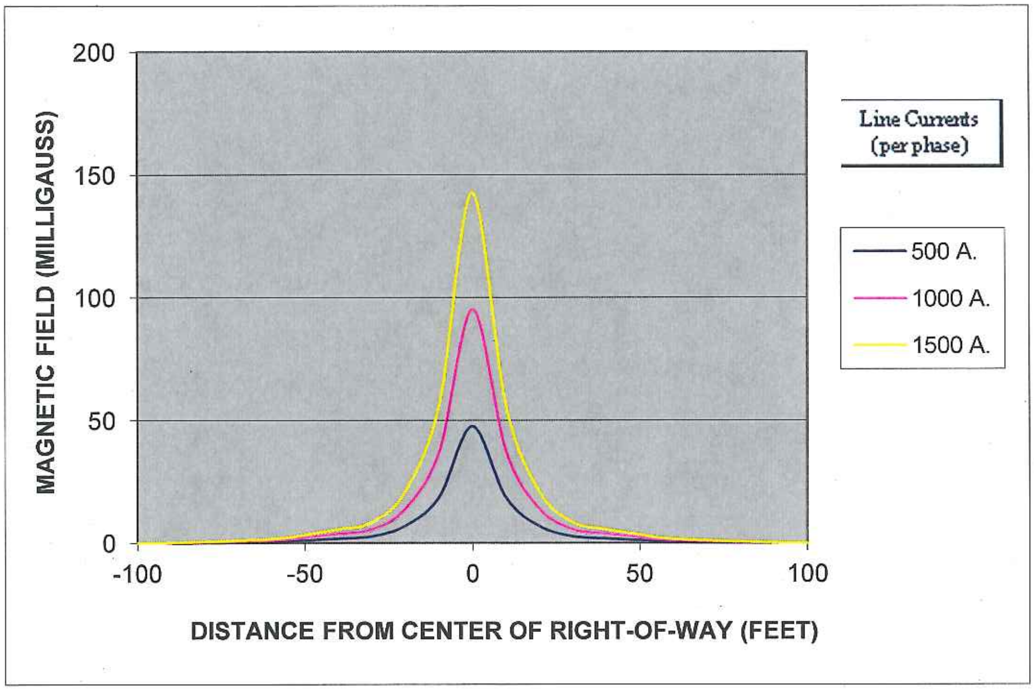



**Figure 8-2: Magnetic Field Profiles for 115 kV XLPE Line with Delta Cable Arrangement Source: Connecticut Siting Council and Acres International Corp. [1].**

### 8.2.2 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 the maximum shielding effect on magnetic fields, compared to a flat steel plate. Figure 8-3 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 Greater Springfield Reliability Project [2], agree in general with the magnitudes shown in Figure 8-3, 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 8-4.

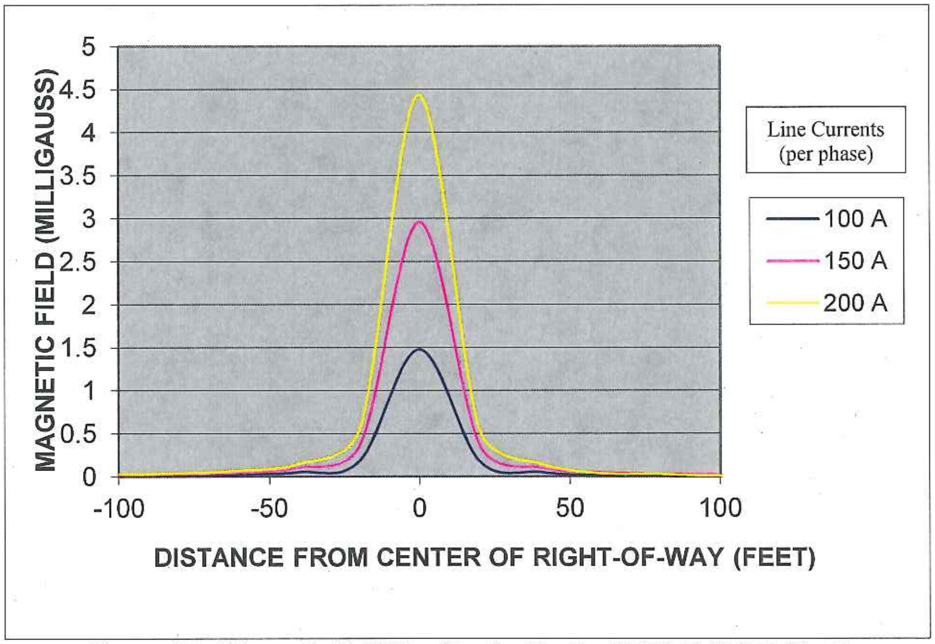



**Figure 8-3: Magnetic Field Profiles for Typical 345 kV HPFF Line***
**Source: Connecticut Siting Council and Acres International Corp. [1].**

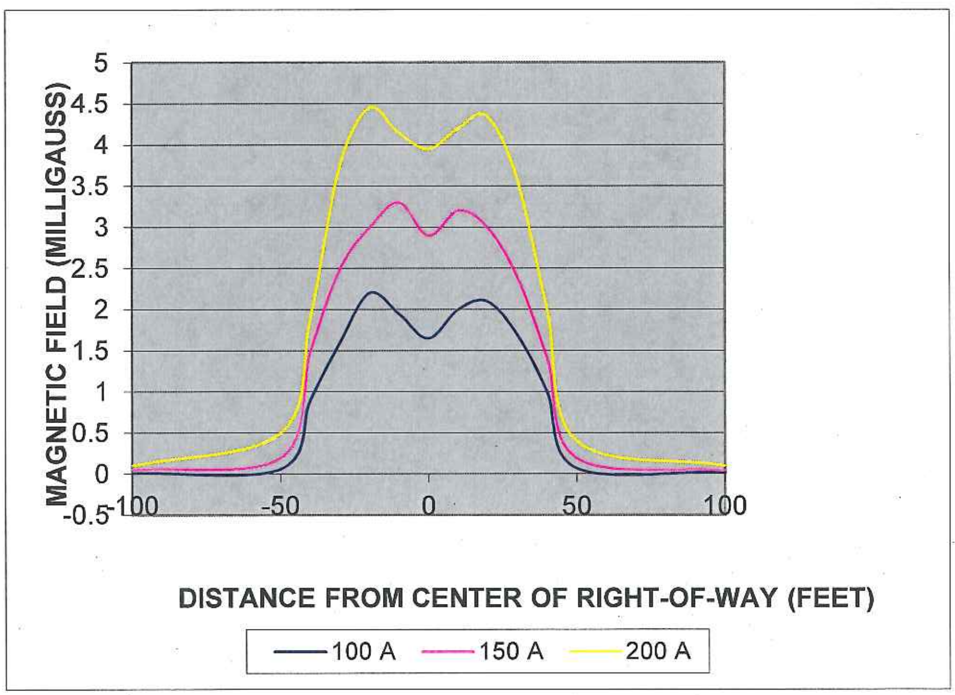



**Figure 8-4: Average of Magnetic Field Measurements for 345 kV HPFF Line***
**Source: CL&P [2].**

### 8.2.3 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 8-2. 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% 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. 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, Q-CSC-019, October 21, 2011. Attachment 1 – "Post-Construction Electric & Magnetic Field Monitoring Plan", and Attachment 2 – "Pipe-Type Cable Magnetic Fields."

# 9. Environmental Considerations and Costs

The State of Connecticut has a diverse and unique environment that is greatly valued by its citizens. Accordingly, it is appropriate that the benefits of protecting and enhancing that environment are weighed against the associated 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.

## 9.1 Environmental issues by resource type

Table 9-1 summarizes the wide variety of environmental impacts that transmission lines can have for each of eight environmental resource categories. These include:

1) Resources related to life and habitat, such as air, water and biological resources;

2) Earth and land-related resources, including topography, geology, land-use and agricultural; and

3) Aesthetic considerations, such as visual, cultural, and historic resources.

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 the State of Virginia it was found that running a 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 right of way would prevent certain forest amphibians from reaching higher elevations to reproduce. Other resources overlap with each other. Most notably, 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 focused on the effects environmental impacts have on transmission line costs.

Both State and Federal agencies oversee certain aspects of Connecticut's environment, as listed in Table 9-2. 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 Department of Energy and Environmental Protection (DEEP) also plays a key role in the siting of transmission facilities. Effects of construction on water quality and storm water are key concerns, and any projects in either coastal zones or "tidally influenced areas" receive greater scrutiny. Impacts in cultural and historic resources are overseen by the Connecticut Historical Commission, which requires a finding of "no adverse effect." Finally the Public Utilities Regulating 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, the U.S. Army Corps of Engineers has the greatest influence. Specifically, The Corps of Engineers requires a Section 404 permit for all dredge and fill activities (including wetlands and watercourses) and requires a Section 10 permit for any work that impact navigable waterways. It is our understanding that the Corps interprets the term "navigable" in very broad terms.

The U.S. Army Corps of Engineers (Corps) review 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, and the U.S. Environmental Protection Agency provide input to the Corps permitting process.

**Table 9-1: Environmental Factors for Transmission Line Siting and Operation**

| Environmental Resources | Potential Impact Issues for Transmission Lines* |
|---|---|
| Water Resources | Erosion and sedimentation into waterbodies.<br>Loss of stream and wetland habitat and function.<br>Alterations in localized groundwater flow due to blasting (e.g., individual wells).<br>Adverse effects on water quality as a result of herbicide use.<br>Adverse effects of access roads and/or facilities placed in or across water resources. |
| Biological Resources | Disturbance to or loss of habitat.<br>Modifications to vegetative diversity.<br>Effects on birds (collisions, electrocution, disruption of nesting by vegetation clearing).<br>Effects of herbicides.<br>Effects on RTE habitat or individuals.<br>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<br>Multiple use of right-of-way<br>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 footing, spans, practicality of undergrounding).<br>Modifications to topography (and effect of topography on feasibility of transmission line installation).<br>Amount of blasting required.<br>Soil erosion and/or instability.<br>Soil compaction. |
| Visual Resources | Intrusive effects of towers and/or maintained right-of-way and other aboveground facilities.<br>Degree of visual contrast to viewers. |
| Cultural Resources | Direct effects on buried cultural resource sites.<br>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 | Decrease in agricultural land production from placement of structures in agricultural areas<br>Impacts to productivity caused by soil mixing, compaction (as a result of equipment access through agricultural areas, trenching)<br>Impacts to livestock |

**Table 9-2: Environmental Permit/Certificate Approvals for Typical Transmission Line**

| Agency | Type of Approval Required |
|---|---|
| **State** | |
| Connecticut Siting Council | Certificate of Environmental<br>Compatibility and Public Need |
| Connecticut Department of Energy and Environmental Protection | 401 Water Quality Certification<br>Storm Water Pollution Prevention<br>Approval for temporary disturbance of more than 5 acres of land<br>Coastal Zone Consistency<br>Certification of Structures and Dredging Permit for coastal zone or tidally influenced areas (from Office of Long Island Sound Programs)<br>Stream Channel Encroachment Line Permit |
| Connecticut Historical Commission | Review of archaeological and historic resources, consistent with the National Historic Preservation Act; approval by finding of no adverse effect |
| Public Utilities Regulating Authority | Method and Manner of Construction approval<br>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. Please note that the nationwide permits have been replaced with Programmatic General Permits.)<br>Section 10 permit for work in navigable waterway |
| Federal Aviation Administration | Notification of presence of overhead lines only |

## 9.2 Effects on line cost

While there are a wide range of environmental impacts associated with transmission line construction and operation, the cost effects of these impacts usually are attributable to one or more of the following cause categories:

- Higher cost tower structures and construction in affected areas
- Design changes to prevent accidental release of fluid
- Avoidance (or circumvention) of affected areas
- Toxic substance handling and disposal
- Site restoration activities
- Delays in project start-up or completion

Each of these categories is discussed briefly, with some examples, in the remainder of this section.

### 9.2.1 Higher cost towers and construction

Power lines that traverse environmentally-sensitive areas, such as wetlands, river crossings, tidal areas, and forested areas with endangered or threatened species, often must use higher cost structures or incur significantly higher construction costs. It is common in such areas to use higher, stronger poles/towers that permit longer spans and fewer foundations. Higher towers also permit the maintenance of vegetation, shrubs, and small trees under overhead lines. Such vegetation preserves moisture and moderates temperatures on the ground level along the line ROW. The higher towers are more expensive and usually require larger and more elaborate foundations.

Higher tower costs can also result from designs required for mitigation of Electro-magnetic Field (EMF) intensity in environmentally-sensitive areas. CL&P and UI together constructed a new 345 kV transmission line between Scovill Rock Switching Station 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].

Construction cost increases may 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.

Work scheduling also can be greatly complicated by efforts to protect fish and wildlife. The former Department of Environmental Protection (DEP) suggested restrictions for the Middletown-Norwalk (M-

N) line provide an illustrative example. Even though no significant watercourse impacts are anticipated from the M-N line, DEP offered the following guidelines for instream work and special habitat areas in its May 4, 2004, letter:

> "...the DEP Inland Fisheries Division suggests in stream work be restricted to the period from June 1 to September 30, inclusive."
>
> "The recommended window for construction activities in areas which support wood turtles and box turtles is November 1 to April 1...If any of these wetlands are riverine wetlands, it will be necessary to avoid any in stream work or access in these areas."
>
> "Unconfined in-water work is often prohibited in selected areas from February 1 to May 15 to protect winter flounder spawning areas. Anadromous migration should be protected from July 1 to September 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..."

### 9.2.2 Design Changes to prevent environmental contamination

Sometimes, transmission line design changes are needed to prevent environmental contamination. In 2008, the Long Island Cable Replacement Project replaced 7 underwater fluid-filled cables with 3 solid dielectric cables to eliminate the potential for accidental release of dielectric 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 the Department of Energy and Environmental Protection (DEEP), the New York Department of Environmental Conservation and Public Service Commission, and the U.S. Army Corps of Engineers. The monitoring plan 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% of all costs and the Long Island Power Authority (LIPA) paid the remainder [1].

### 9.2.3 Avoidance of affected 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 higher cost structures, due to a less direct route and more angles in the ROW. For one important 765 kV transmission line from West Virginia to Virginia, the designation of a major river as "wild and scenic" by the Environmental Protection Agency caused the entire line application to be withdrawn and a new route identified. Several years were required to develop a new, much longer route."

The application phase for the Middletown-Norwalk (M-N) line provides numerous examples of the need to avoid environmentally sensitive areas. In some instances, complete avoidance was impossible, and it was necessary to select a route that would minimize exposure. For example, the Applicants for the line observed, "There are some wetlands that run longitudinally along the right-of-way for a distance, making it difficult to avoid wetland impacts. The Applicants would determine the area of the wetland where the depth of the water is the shallowest, and would minimize the impact of construction on that wetland."

In the most heavily developed sections of Southwest Connecticut, marine routes seemed to be an attractive option. However, shellfish beds presented a nearly insurmountable obstacle. For example, it was found that, "A route from the East Shore into New Haven harbor would have impacts to shellfish beds...The route would have to traverse the Housatonic River, a major source of seed oysters, and pass the Steward B. McKinney National Wildlife Refuge." Similarly, "the feasibility of a marine route from Singer Substation to Norwalk Substation was considered. Such a route would cross shellfish beds."

Also, the Coastal Zone Management Act scrutinizes shoreline development in the context of a "water-dependent" use. That is to say that 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 M-N line routing include:

> The Applicants support a change of the proposed transmission line infrastructure within the Town of Westport (that) would reduce the length of the proposed route by approximately 2,750 feet and avoid the Westport historic district."
>
> In place of the proposed Norwalk River crossing, the Applicants support a change with an alternate crossing that would...avoid disruption of the cemetery location."

Both of these examples reflect cases where site avoidance actually could reduce costs by shortening the total line length. Thus, the scrutiny of line applications by various parties can in some instances lead to cost *benefits*.

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

### 9.2.4 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 has been a major cost concern for the proposed M-N line in Southwest Connecticut. There are several reasons:

- Much of the line is to be constructed under existing state highways, and a significant amount of the soil under these highways is already contaminated. Once removed, however, the soil cannot be returned but must be replaced with uncontaminated soil.

- The proposed route will cross both the Middletown-Durham and Wallingford landfills, and DEP requires that, "If any new pole structures fall within the footprint of any previously placed waste, an authorization for disruption of a solid waste disposal area must be obtained from the DEP Bureau of Waste Management."

- Testing for trichloroethylene (TCE) is required at the East Devon Substation site. "If contamination is found, removal and disposal of contaminated soils will be required."

Once contaminated soil is removed, it must be treated as contaminated and be properly disposed of, often involving transportation out of the state. Temporary storage prior to this removal also may incur high costs and subsequent clean-up.

The underground line portion of the Middletown-Norwalk 345 kV line construction required soil excavation where the cable duct-banks would be located. Soil sampling and characterization revealed that most of the soil needed to be disposed of at an approved facility. The total cost for soil sampling, testing, and disposal was $2.9 million for CL&P [1] and $14.6 million for UI [2].

CL&P also constructed a new 8.7-mile underground 115 kV cable system from Glenbrook Substation to Norwalk Substation which required soil excavation where the duct banks would be located. Soil sampling and characterization revealed that most of the soil needed to be disposed of at an approved facility. The total cost for soil sampling, testing, and disposal was $2.5 million [1].

### 9.2.5 Site restoration and Wetlands Creation

Site restoration costs may be incurred in some locations. Typical examples include agricultural sites and areas with erodable soils and steep grades. The associated costs could include re-grading and/or the planting of vegetation to prevent erosion. 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.

Sometimes, site restoration involves wetlands. Such was the case for the Middletown to Norwalk 345 kV Project. The project required permits from the U.S. Army Corps of Engineers and the Connecticut Department of Environmental Protection, which required the creation of a 2.2-acre wetland at Eisenhower Park in Milford, CT and a conservation easement on 74 acres if CL&P property in Middletown, CT. The total cost of constructing the wetland, including engineering and legal costs, was $2.2 million [1].

### 9.2.6 Delays in project completion

Environmental reviews, discovery, and investigations may lead to necessary, but substantial delays in line construction and commissioning. During these periods of delay, escalations in both material costs and labor costs can cause substantial increases in a line's first costs, which are the largest component of its life-cycle cost. The increase in transmission line life-cycle costs since the last Connecticut Siting Council LCC study in 2007 shows that this escalation is significantly higher than the general inflation rate over the same time period.

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.

# 10. Life-Cycle Cost Calculations for Reference Lines

As outlined in Chapter 2 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 Chapter 2 however, the useful life period used in a Present Value Life-cycle Cost calculation is less important as an absolute term than as a comparison of assets over an equivalent period of service. Also, as illustrated in that chapter, the first costs of a transmission line project are the primary drivers of life-cycle costs with the cost of electrical losses being the most significant ongoing cost.

For the purpose of life-cycle costs calculations for this study, a period of forty years has been used. This is a term that is believed by the Connecticut utilities to be a fair representation of a life-cycle analysis period for transmission lines and is consistent with models they employ.

This chapter offers information on the results of life-cycle cost calculations for the twelve transmission line designs that were identified in Chapter 3. These twelve 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.

## 10.1 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 indicators and calculation variables used along with the values assumed include:

| | |
|---|---|
| Capital recovery factor: | 14.1% |
| Operation and maintenance cost escalation: | 4.0% |
| Load growth: | 2.03% |
| Energy cost escalation | 5.0% |
| Discount rate: | 8.0% |

These factors are consistent with previous LCC studies done for the Connecticut Siting Council and are representative of variables used by utilities in their cost calculations. More detail on each variable follows.

**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% was provided by CL&P and is typical for Connecticut transmission lines.

**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%, 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 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% 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 4% per year has been assumed.

**Discount rate**: An interest rate of 8% 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 Net Present Value (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 in many instances in this report, 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.

## 10.2 Life-cycle Cost Comparison

The cumulative present value of a life-cycle cost 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 overhead versus underground design is the primary contributor to the life-cycle cost and can represent differences in costs by factors as high as 4 to 6 times. Within a specific overhead or underground design, however, there are also differences that can vary the cost of a line significantly.

Table 10-1 shows the NPV of total life-cycle costs for each of the overhead lines considered.

**Table 10-1: NPV of Overhead Transmission Line Life-Cycle Cost Components**

| LCC Component | 115 kV Wood H-Frame | 115 kV Steel Delta | 115 kV Steel Double-Circuit | 345 kV Wood H-Frame | 345 kV Steel Delta |
|---|---|---|---|---|---|
| Poles & Foundations | $1,034,631 | $2,450,297 | $3,887,508 | $2,280,275 | $4,739,447 |
| Conductor & Hardware | $1,307,434 | $1,410,458 | $2,668,311 | $2,476,827 | $3,043,953 |
| Site Work | $1,616,554 | $2,483,186 | $2,644,159 | $2,435,045 | $2,850,427 |
| Construction | $227,826 | $229,568 | $248,754 | $228,919 | $247,750 |
| Engineering | $334,465 | $818,996 | $568,421 | $455,752 | $648,572 |
| Sales Tax | $118,215 | $188,155 | $313,010 | $229,357 | $369,433 |
| Admin/PM | $935,291 | $609,297 | $1,038,253 | $1,008,872 | $1,071,855 |
| Losses | $4,495,708 | $4,495,708 | $4,495,708 | $1,825,530 | $1,825,530 |
| O&M Costs | $96,631 | $96,631 | $96,631 | $96,631 | $96,631 |
| Total LCC | $10,166,755 | $9,298,794 | $15,960,756 | $11,037,207 | $14,893,598 |

The following observations can be made from Table 10-1 about the total NPV of the life-cycle costs for the different overhead transmission construction types:

- 115KV Lines: Life-cycle cost of Wood H-frame is 9% higher than Steel delta.
- 345KV Lines: Life-cycle cost of Steel delta is 35% higher than Wood H-frame.
- Wood H-frame Lines: Life-cycle cost of 345kV is only 8% higher than 115 kV.
- Steel Delta Lines: Life-cycle cost of 345kV is 60% higher than 115kV.

Figure 10-1 shows the yearly growth in cumulative NPV of life-cycle costs over the 40-year life for each of the overhead line designs discussed in this report.

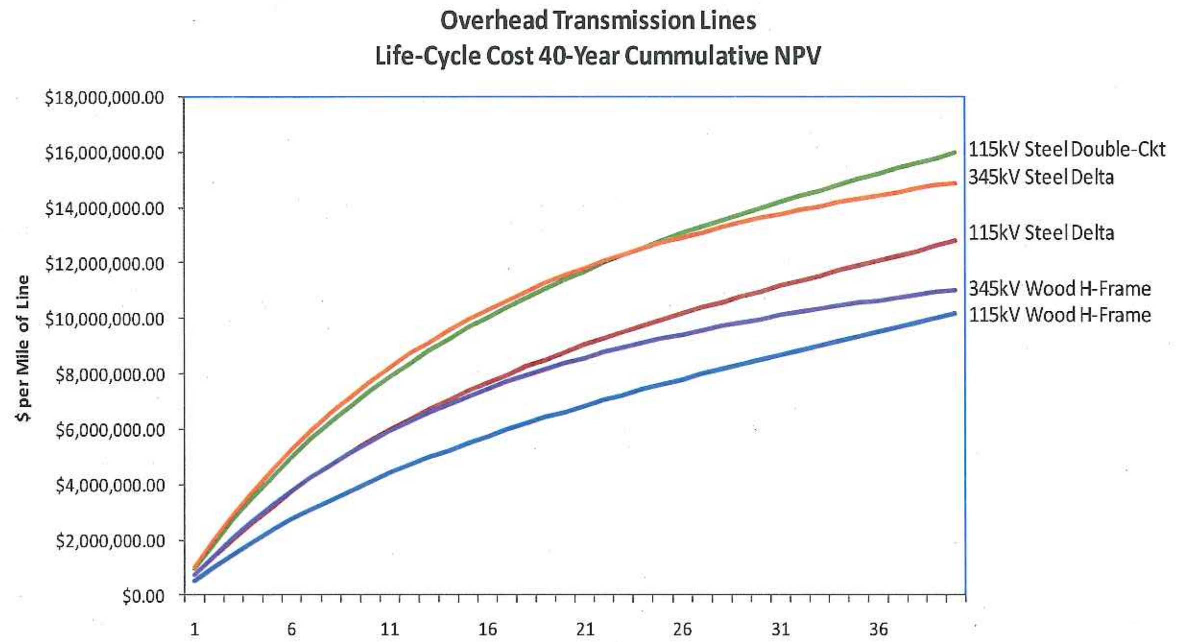



**Figure 10-1: Overhead Transmission Line Life-Cycle Costs**

Figure 10-1 shows that for single-circuit lines, 345 kV Steel Delta construction has the highest life-cycle cost, followed by 115 kV Steel Delta, then 345 kV Wood H-frame, with 115 kV Wood H-frame the least costly. A cross-over occurs between 115 kV Steel Delta and 345 kV Wood H-frame because the losses are higher at 115 kV.

Table 10-2 shows the NPV of total life-cycle costs for each of the underground lines considered.

**Table 10-2: NPV of Underground Transmission Line Life-Cycle Cost Components**

| LCC Component | 115kV XLPE | 115kV HPFF | 115 kV XLPE Double-Circuit | 345 kV XLPE | 345 kV HPFF | 345kV XLPE Double-Circuit | 345kV HPFF Double-Circuit |
|---|---|---|---|---|---|---|---|
| Ducts & Vaults | $10,104,687 | $8,935,795 | $15,540,060 | $11,821,084 | $9,928,661 | $18,186,779 | $15,274,864 |
| Cable & Hardware | $11,052,001 | $7,677,232 | $16,996,941 | $12,929,310 | $8,530,258 | $19,891,790 | $13,123,475 |
| Site Work | $5,052,343 | $4,530,826 | $7,770,030 | $5,910,542 | $5,034,250 | $9,093,390 | $7,745,001 |
| Construction | $631,543 | $503,426 | $971,254 | $738,818 | $559,362 | $1,136,674 | $860,556 |
| Engineering | $789,429 | $629,281 | $1,456,881 | $1,108,227 | $839,042 | $2,841,684 | $1,075,695 |
| Sales Tax | $1,002,259 | $787,357 | $1,541,380 | $1,172,504 | $874,841 | $1,803,901 | $1,345,909 |
| Admin/PM | $2,944,885 | $2,107,338 | $4,286,143 | $3,260,403 | $2,201,647 | $3,879,467 | $3,602,286 |
| Losses | $1,382,989 | $1,636,452 | $1,382,989 | $1,382,989 | $1,636,452 | $1,382,989 | $1,636,452 |
| O&M Costs | $177,000 | $177,000 | $177,000 | $177,000 | $177,000 | $96,631 | $177,000 |
| Total LCC | $33,137,136 | $26,984,706 | $50,122,677 | $38,500,876 | $29,781,513 | $58,313,306 | $44,841,237 |

These results show the degree to which first costs dominate the LCCs of underground transmission lines. The O&M components for every category made up only 1% of the total life-cycle costs. The Loss component of life-cycle costs for overhead lines was 44-48% for 115 kV and 12-28% for 345 kV, but it represents only 3-5% of the total life-cycle cost of underground lines. This is due to two facts: 1) the underground conductors used in this comparison were larger than the overhead conductors, resulting in lower loss costs, and 2) the first-costs for underground lines are 3 to 5 times those of 115 kV overhead lines and 2 to 3 times those of 345 kV overhead lines. The following observations can be made from Table 10-2 about the total life-cycle costs for the different underground construction types:

- XLPE Cables: 345kV life-cycle costs are 16% higher than 115 kV.
- Double-Circuits: 345kV costs are also 16% higher than 115 kV for XLPE cables.
- HPFF Cables: 345kV life-cycle costs are only 9% higher than 115 kV.
- 115 kV Circuits: XLPE cable life-cycle costs are 24% higher than HPFF cables. Double-circuit life-cycle costs are 53% higher than single-circuits for XLPE cables.
- 345 kV Circuits: XLPE cable life-cycle costs are 31% higher than HPFF cables.
- DOUBLE-CIRCUITS: XLPE cable life-cycle costs are 30% higher than HPFF cables.

Figure 10-2 shows the yearly growth in cumulative NPV of life-cycle costs over the 40- year life for each of the underground lines considered.

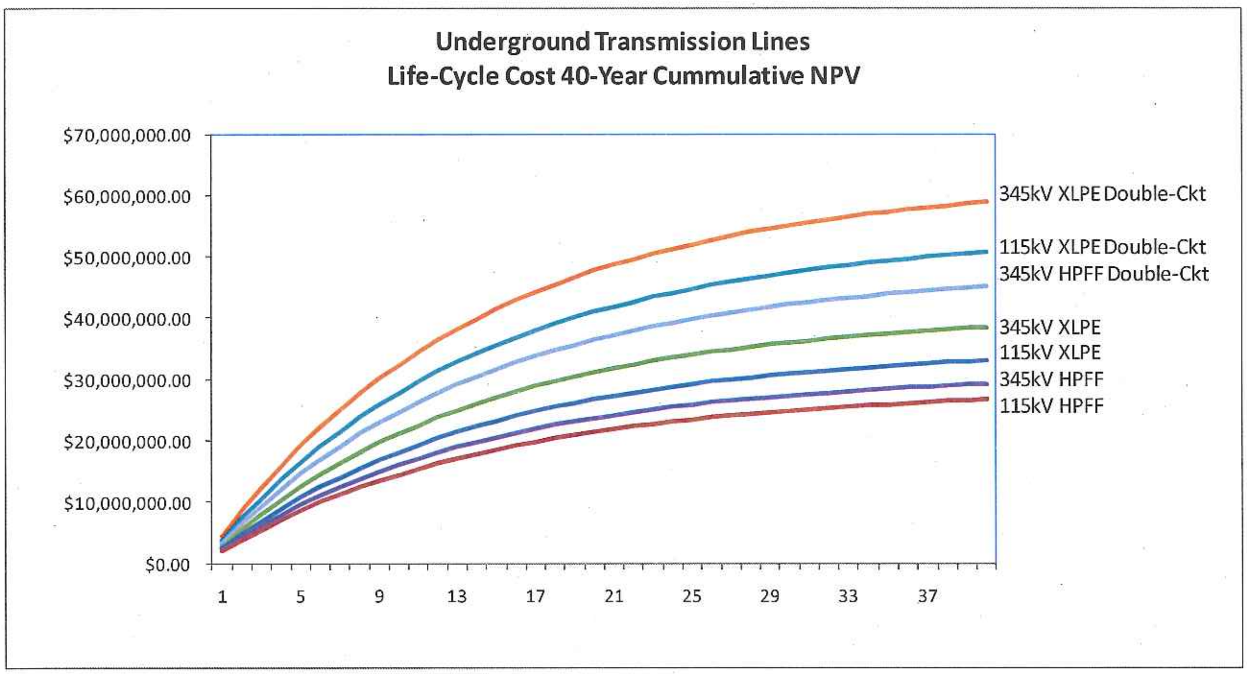



**Figure 10-2: Underground Transmission Line Life-Cycle Costs**

The relative cost of a 345 kV XLPE line versus a 345 kV HPFF line is 31% more. Also of interest is the relatively small difference in NPV between a 345 kV HPFF line and either 115 kV alternative. In fact, the relative cost of a 345 kV HPFF line is actually 12% less than for a 115 kV XLPE line.

Figure 10-3 shows how the cumulative Net Present Value (NPV) of the life-cycle cost components varies over time for a typical 115 kV overhead line. This illustrates how first costs dominate the life-cycle cost calculation until the present value of losses eventually become a larger contributor after year 24. Since O&M costs represent only 1% of the overall transmission life-cycle cost, they cannot be seen on this graph. For the other 3 "typical" overhead transmission line construction types, losses and O&M are such a small percentage of the life-cycle cost that they cannot be seen on the graph.

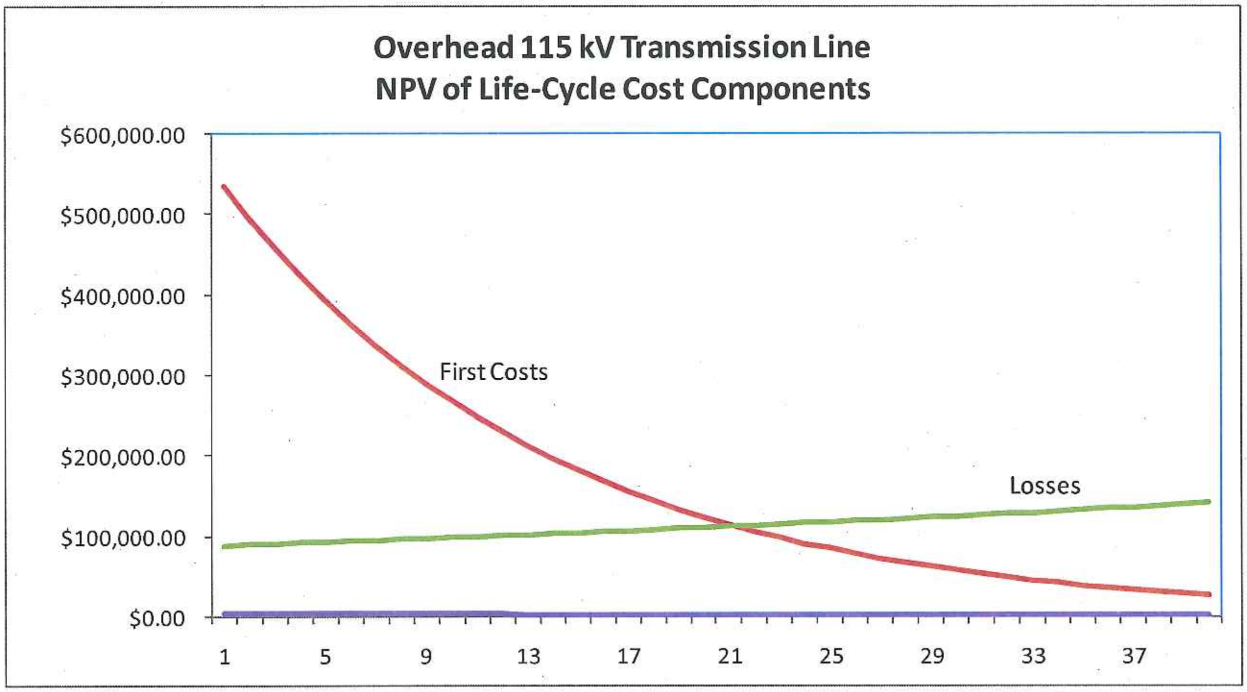



**Figure 10-3: Overhead 115 kV Transmission Line Cost Components**

Figure 10-4 compares the 2007 overhead life-cycle costs with the 2012 overhead life-cycle results.

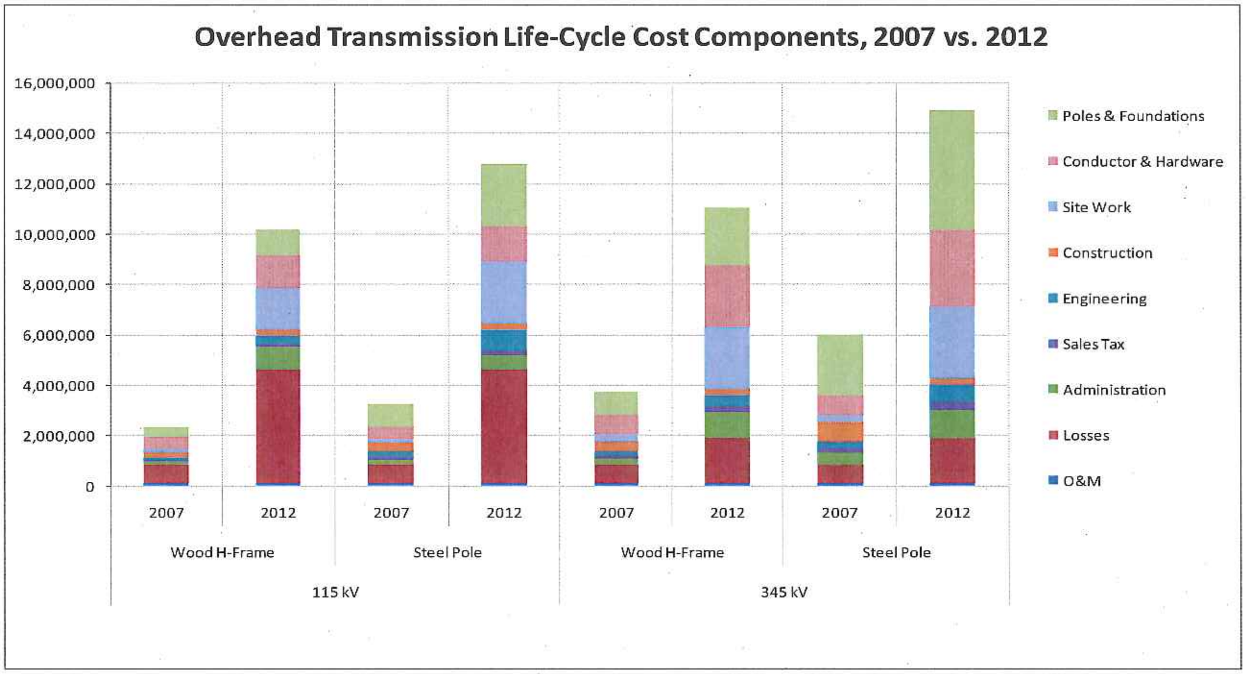



**Figure 10-4: Comparison of 2007 and 2012 Overhead Transmission Line Cost Components**

Figure 10-4 shows that overhead transmission life-cycle costs, particularly first-costs, have increased dramatically since the 2007 report. The actual numbers for the 2007 life-cycle costs and the 2012 results are compared in Table 10-3.

**Table 10-3: Comparison of 2007 and 2012 Overhead Life-Cycle Cost Components**

| | 115 kV | | | | 345 kV | | | |
|---|---|---|---|---|---|---|---|---|
| | Wood H-Frame | | Steel Pole | | Wood H-Frame | | Steel Pole | |
| | 2007 | 2012 | 2007 | 2012 | 2007 | 2012 | 2007 | 2012 |
| Poles & Foundations | $419,633 | $1,034,631 | $904,156 | $2,450,297 | $931,247 | $2,280,275 | $2,445,721 | $4,739,447 |
| Conductor & Hardware | $474,872 | $1,307,434 | $474,872 | $1,410,458 | $788,551 | $2,476,827 | $788,830 | $3,043,953 |
| Site Work | $127,854 | $1,616,554 | $127,854 | $2,483,186 | $258,095 | $2,435,045 | $258,095 | $2,850,427 |
| Construction | $221,801 | $227,826 | $348,900 | $229,568 | $424,961 | $228,919 | $770,017 | $247,750 |
| Engineering | $86,646 | $334,465 | $237,615 | $818,996 | $146,914 | $455,752 | $248,443 | $648,572 |
| Sales Tax | $61,218 | $118,215 | $96,296 | $188,155 | $117,289 | $229,357 | $212,525 | $369,433 |
| Administration | $139,202 | $935,291 | $218,970 | $609,297 | $266,705 | $1,008,872 | $483,263 | $1,071,855 |
| Losses | $710,162 | $4,495,708 | $710,162 | $4,495,708 | $710,162 | $1,825,530 | $710,162 | $1,825,530 |
| O&M | $115,689 | $96,631 | $115,689 | $96,631 | $115,689 | $96,631 | $115,689 | $96,631 |
| TOTAL LCC | $2,357,077 | $10,166,755 | $3,234,514 | $12,782,295 | $3,759,613 | $11,037,207 | $6,032,745 | $14,893,598 |

* Wood Laminate structures no longer used. 2012 costs represent standard wood H-Frame structures for 345 kV Transmission Lines

The following observations can be made from Table 10-3:

Typical 115 kV Wood life-cycle costs have gone up 331% since 2007 (a 34% average annual increase).

Typical 115 kV Steel life-cycle costs have gone up 295% since 2007 (a 31% average annual increase).
Typical 345 kV Wood H-frame costs have gone up 194% since 2007 (a 24% average annual increase).
Typical 345 kV Steel life-cycle costs have gone up 147% since 2007 (a 19% average annual increase).

Furthermore, a few of the major cost components have had huge increases:

Poles & Foundations: 147% for 115 kV Wood (a 19% average annual increase),
171% for 115 kV Steel (a 22% average annual increase),
145% for 345 kV Wood (a 19% average annual increase),
94% for 345 kV Steel (a 14% average annual increase).

Conductor & Hardware: 175% for 115 kV Wood (a 22% average annual increase),
197% for 115 kV Steel (a 24% average annual increase),
214% for 345 kV Wood (a 25% average annual increase),
286% for 345 kV Steel (a 31% average annual increase),

Site Work: 1164% for 115 kV Wood (a 66% average annual increase),
1842% for 115 kV Steel (a 81% average annual increase),
843% for 345 kV Wood (a 56% average annual increase),
1004% for 345 kV Steel (a 61% average annual increase).

The very large increases in the cost of site work can be directly attributed to the environmental costs that utilities in the state have experienced due to regulatory requirements. CL&P provided several examples of extra measures that were undertaken to comply with environmental regulations that resulted in greatly increased costs for site work. These were discussed previously in section 9.

Figure 10-5 compares the 2007 overhead life-cycle material costs with those for 2012.

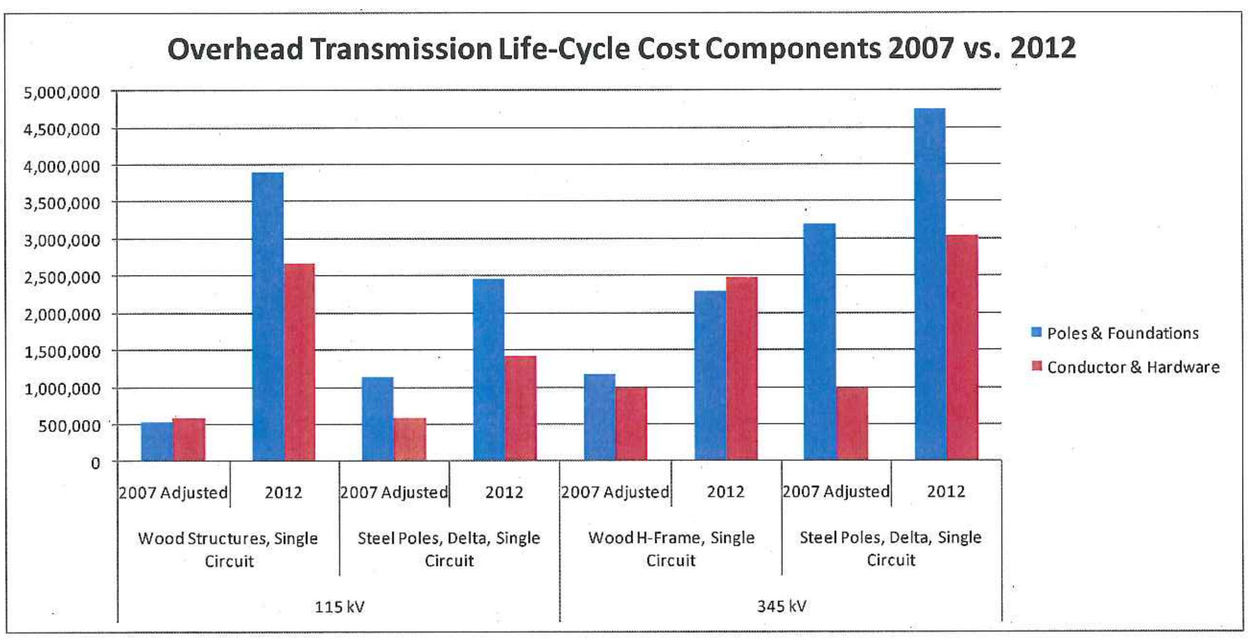



**Figure 10-5: Comparison of 2007 and 2012 Overhead Transmission Line Material Costs**

This shows graphically the large increases in material costs since the 2007 report was prepared. Material costs for wood and steel have gone up significantly in recent years, which mostly accounts for the large increase in the cost for poles, foundations, conductor, and hardware.

Figure 10-6 compares the 2007 underground life-cycle costs with the 2012 underground life-cycle results. This shows that underground transmission life-cycle costs, particularly first-costs, have increased greatly since the 2007 report.

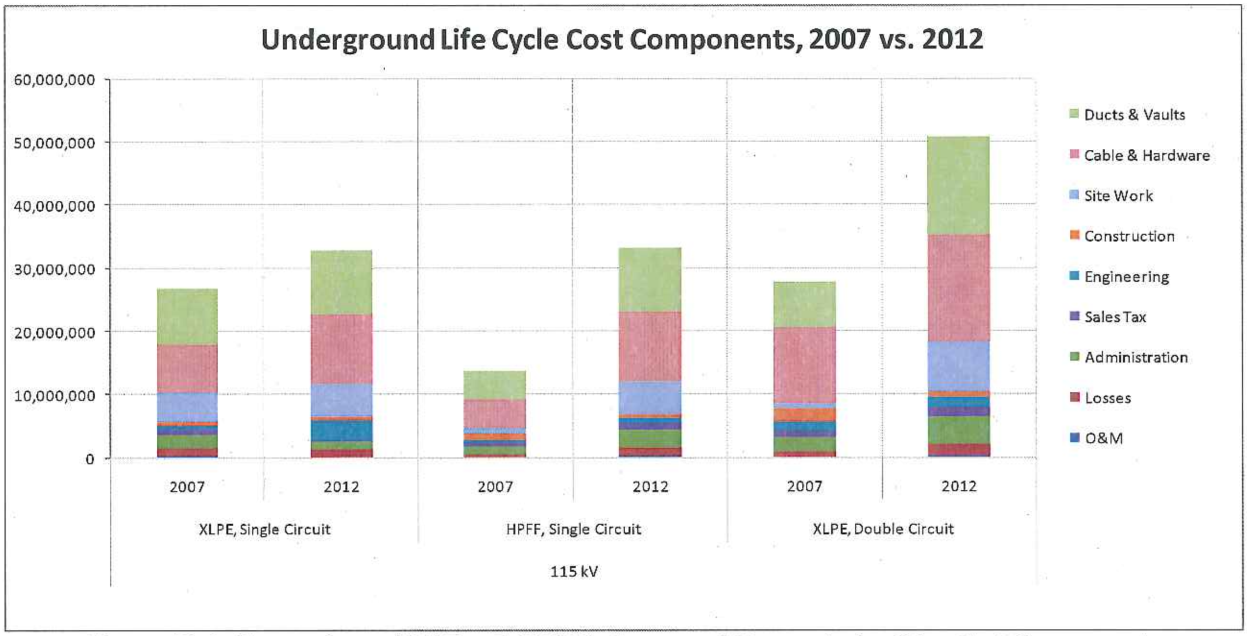



**Figure 10-6: Comparison of 2007 and 2012 Underground Transmission Line Cost Components**

A comparison between the 2007 life-cycle costs and the 2012 results are summarized in Table 10-4.

**Table 10-4: Underground Life-Cycle Cost Components for 2007 and 2012**

| | 115 kV | | | | | | 345 kV | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | XLPE, Single-Circuit | | HPFF, Single-Circuit | | XLPE, Double-Circuit | | XLPE, Double-Circuit | | HPFF, Double-Circuit | |
| | 2007 | 2012 | 2007 | 2012 | 2007 | 2012 | 2007 | 2012 | 2007 | 2012 |
| Ducts & Vaults | $5,925,746 | $10,104,687 | $4,633,392 | $8,935,795 | $7,228,003 | $15,540,060 | $7,228,003 | $18,186,779 | $5,331,430 | $15,274,864 |
| Cable & Hardware | $2,236,323 | $11,052,001 | $4,439,878 | $7,677,232 | $11,925,157 | $16,996,941 | $11,925,157 | $19,891,790 | $5,190,766 | $13,123,475 |
| Site Work | $861,415 | $5,052,343 | $861,415 | $4,530,826 | $869,945 | $7,770,030 | $869,945 | $9,093,390 | $241,480 | $7,745,001 |
| Construction | $1,159,085 | $631,543 | $1,159,085 | $503,426 | $2,136,106 | $971,254 | $2,136,106 | $1,136,674 | $1,076,368 | $860,556 |
| Engineering | $340,279 | $789,429 | $341,611 | $629,281 | $1,337,960 | $1,456,881 | $1,337,960 | $2,841,684 | $355,201 | $1,075,695 |
| Sales Tax | $484,051 | $1,002,259 | $526,028 | $787,357 | $982,609 | $1,541,380 | $982,609 | $1,803,901 | $560,981 | $1,345,909 |
| Administration | $1,317,427 | $2,944,885 | $1,390,899 | $2,107,338 | $2,447,977 | $4,286,143 | $2,447,977 | $3,879,467 | $1,275,623 | $3,602,286 |
| Losses | $378,138 | $1,382,989 | $378,138 | $1,636,452 | $756,276 | $1,382,989 | $756,276 | $1,382,989 | $756,276 | $1,636,452 |
| O&M | $54,048 | $177,000 | $54,048 | $177,000 | $54,048 | $177,000 | $54,048 | $96,631 | $54,048 | $177,000 |
| TOTAL LCC | $12,756,512 | $33,137,136 | $13,784,494 | $26,984,706 | $27,738,081 | $50,122,677 | $27,738,081 | $58,313,306 | $14,842,173 | $44,841,237 |

From Table 10-4, the following observations can be made:

Typical 115 kV XLPE life-cycle costs have gone up 159% since 2007 (a 21% average annual increase).
Typical 115 kV HPFF life-cycle costs have gone up 95% since 2007 (a 14% average annual increase).
Typical 115 kV XLPE double-circuit life-cycle costs have gone up 80% since 2007 (a 12% average annual increase).
Typical 345 kV XLPE double-circuit life-cycle costs have gone up 110% since 2007 (a 16% average annual increase).
Typical 345 kV HPFF double-circuit life-cycle costs have gone up 202% since 2007 (a 24% average annual increase).

Furthermore, a few of the major cost components reveal huge increases:

| | |
|---|---|
| Ducts & Vaults: | 151% for 345 kV XLPE double-circuit lines (a 20% average annual increase), 186% for 345 kV HPFF double-circuit lines (a 23% average annual increase). |
| Cables & Hardware: | 394% for 115 kV XLPE single-circuit lines (a 37% average annual increase), 152% for 345 kV HPFF double-circuit lines (a 20% average annual increase). |
| Site Work: | 486% for 115 kV XLPE single-circuit lines (a 42% average annual increase), 426% for 115 kV HPFF single-circuit lines (a 39% average annual increase), 893% for 115 kV XLPE double-circuit lines (a 55% average annual increase), 945% for 345 kV XLPE double-circuit lines (a 59% average annual increase), 3107% for 345 kV HPFF double-circuit lines (a 100% average annual increase). |

The huge increases in the cost of site work can be directly attributed to the environmental costs that utilities in the state have experienced due to regulatory requirements. CL&P provided several examples of extra measures that were undertaken to comply with environmental regulations that resulted in greatly increased costs for site work. These were discussed previously in section 9.

**Conductor Sensitivity**

The life-cycle costs for each of the "typical" overhead lines were re-calculated to determine what the relative difference in life-cycle cost would be with the conductor change from ACSR to ACSS. To perform this "sensitivity" analysis, the following assumptions were used:

1. The cost of poles and foundations would be 10% higher for ACSR conductor than ACSS conductor.
2. The cost of conductor & hardware would be 25% lower for ACSR conductor than ACSS conductor.

The result of this sensitivity analysis, shown in Table 10-5, reveal that for most overhead lines, the difference in life-cycle cost using ACSS conductors is within 3% of the ACSR life-cycle cost, and is actually 37% less for 115 kV Steel Delta lines.

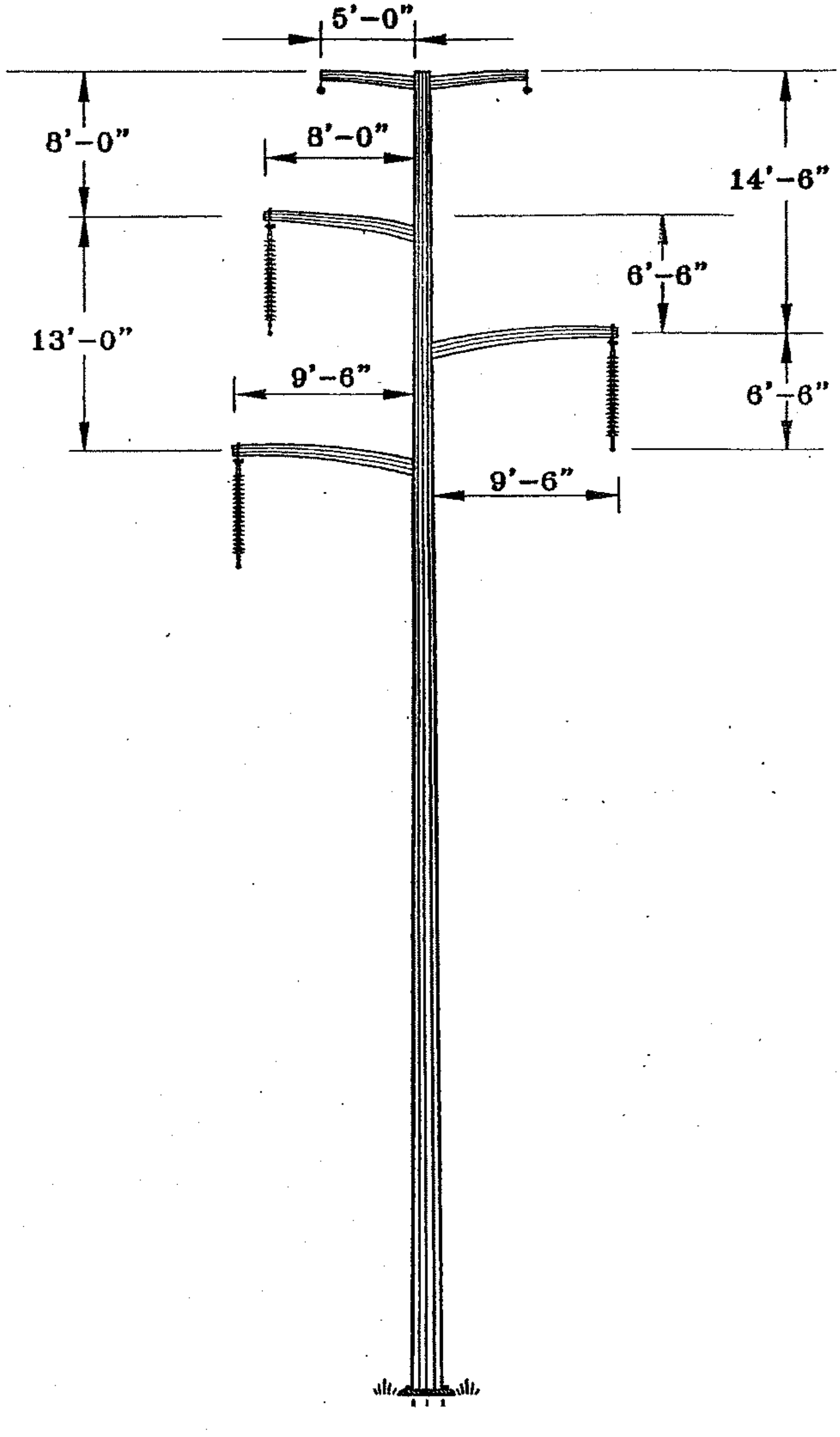
**Table 10-5: Difference in Life-Cycle Costs between ACSS and ACSR Conductors**

| | 115 kV Wood H-Frame | | 115 kV Steel Delta | | 345 kV Wood H-Frame | | 345 kV Steel Delta | |
|---|---|---|---|---|---|---|---|---|
| LCC Component | ACSS | ACSR | ACSS | ACSR | ACSS | ACSR | ACSS | ACSR |
| Poles & Foundations | $1,034,631 | $1,138,094 | $2,450,297 | $2,695,326 | $2,280,275 | $2,508,302 | $4,739,447 | $5,213,392 |
| Conductor & Hardware | $1,307,434 | $980,575 | $1,410,458 | $1,057,843 | $2,476,827 | $1,857,620 | $3,043,953 | $2,282,965 |
| Site Work | $1,616,554 | $1,616,554 | $2,483,186 | $2,483,186 | $2,435,045 | $2,435,045 | $2,850,427 | $2,850,427 |
| Construction | $227,826 | $227,826 | $229,568 | $229,568 | $228,919 | $228,919 | $247,750 | $247,750 |
| Engineering | $334,465 | $334,465 | $818,996 | $818,996 | $455,752 | $455,752 | $648,572 | $618,572 |
| Sales Tax | $118,215 | $118,215 | $188,155 | $118,155 | $229,357 | $229,357 | $369,433 | $369,433 |
| Admin/PM | $935,291 | $935,921 | $609,297 | $609,297 | $1,008,872 | $1,008,872 | $1,071,855 | $1,071,855 |
| Losses | $4,495,708 | $4,659,188 | $4,495,708 | $4,659,188 | $1,825,530 | $1,893,647 | $1,825,530 | $1,893,647 |
| O&M Costs | $96,631 | $96,631 | $96,631 | $96,631 | $96,631 | $96,631 | $96,631 | $96,631 |
| Total LCC | $10,166,755 | $10,107,469 | $9,298,794 | $12,768,190 | $11,037,207 | $10,714,145 | $14,893,598 | $14,644,672 |
| **% Difference** | **0.587%** | **-0.583%** | **-27.172%** | **37.310%** | **3.015%** | **-2.927%** | **1.700%** | **-1.671%** |

The assumed ratios used in this analysis are based on engineering judgment as the best available "rule of thumb" to use for this type of analysis. Actual costs for the transmission line designs required to meet a specific application may not follow these rules of thumb and would be a much better source of data for comparison of life-cycle cost alternatives. In any event, this analysis does show that the technical and operational advantages gained by switching to ACSS conductor are worth the low impact on total overhead transmission line life-cycle costs, and in some cases, could actually cost less.

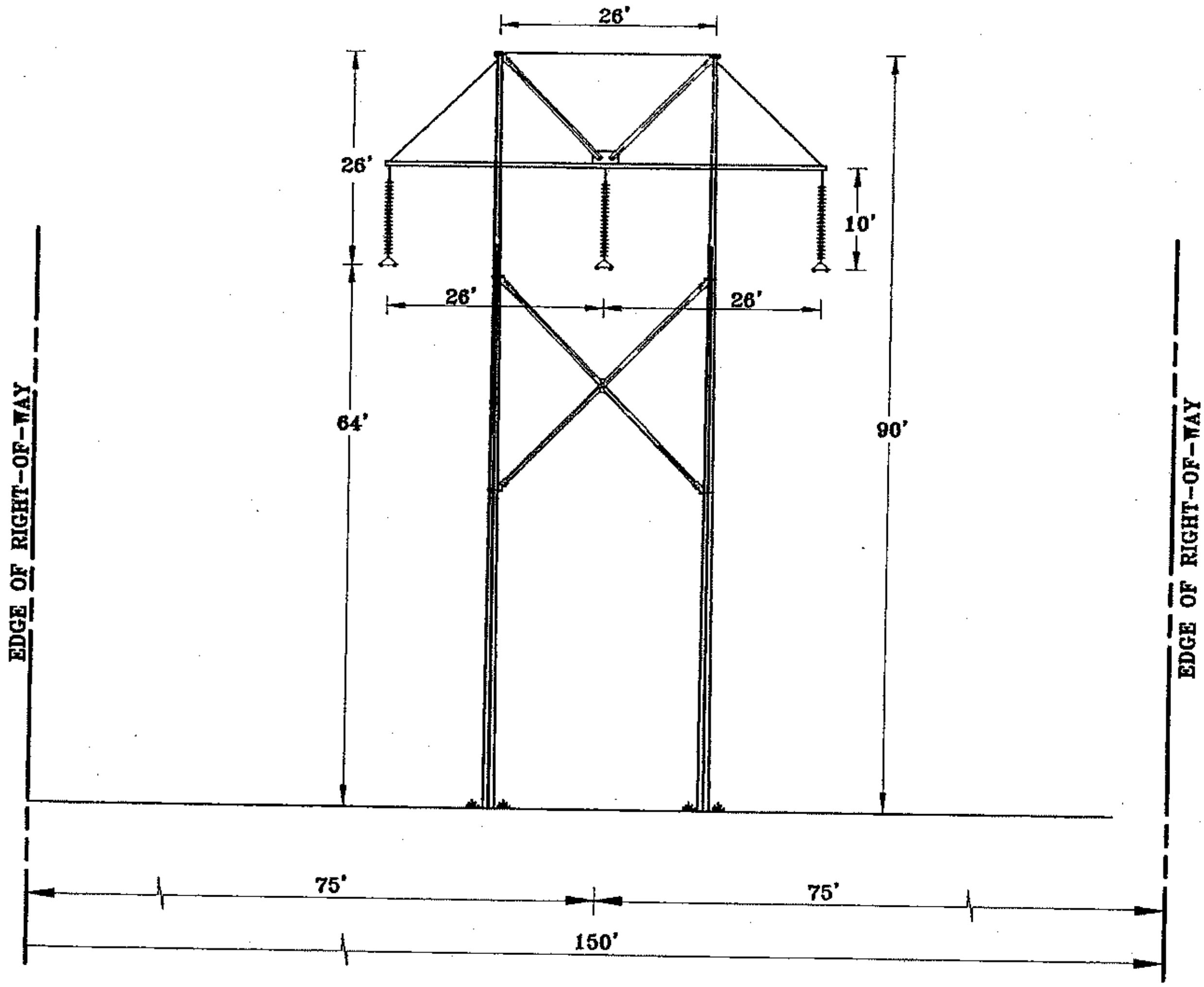
# Appendix A – Line Configuration Drawings

## Typical 115KV Overhead Steel Pole with Delta Configuration



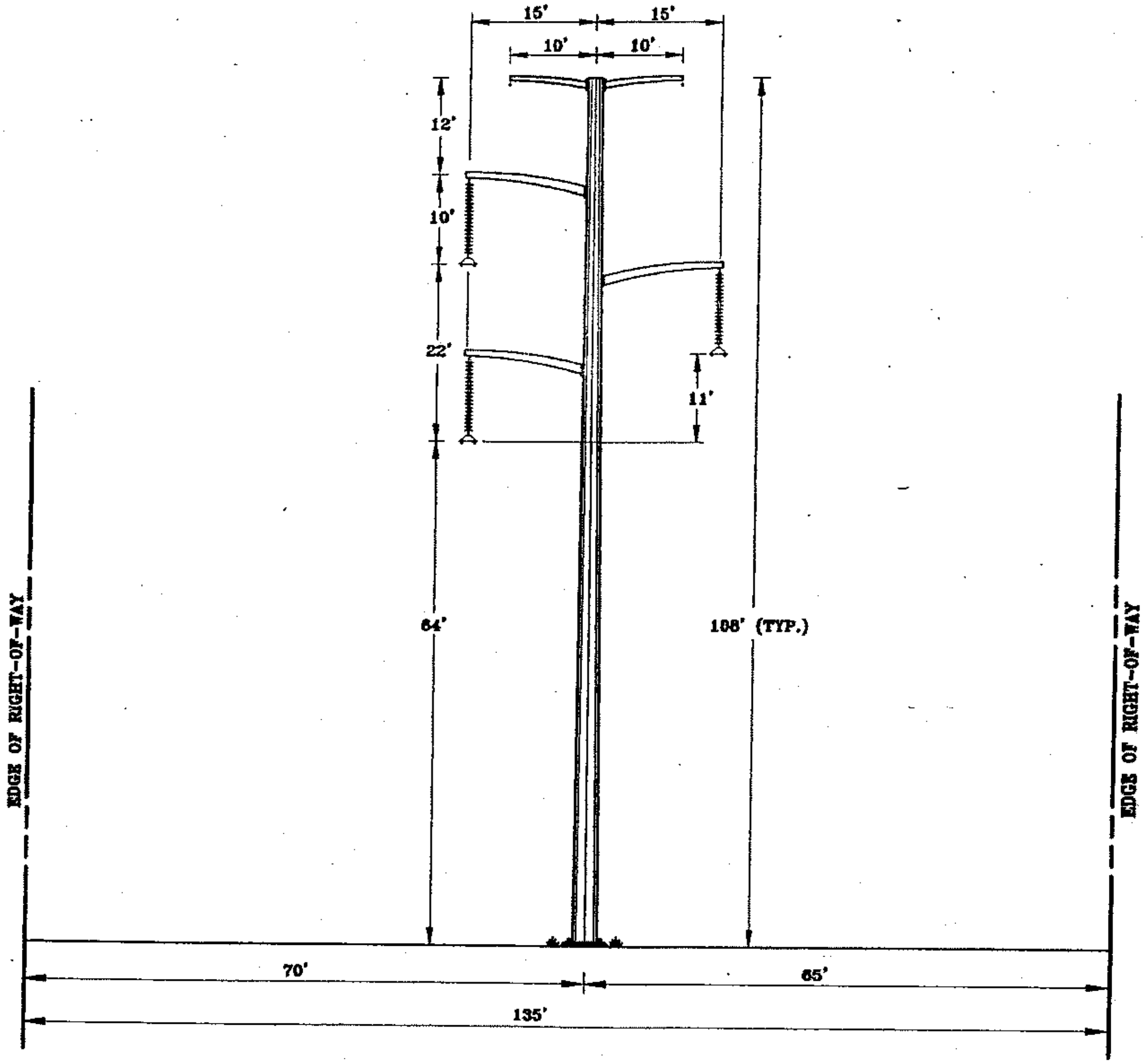

(Source: CL&P)

## Typical Overhead Wood H-Frame Configuration



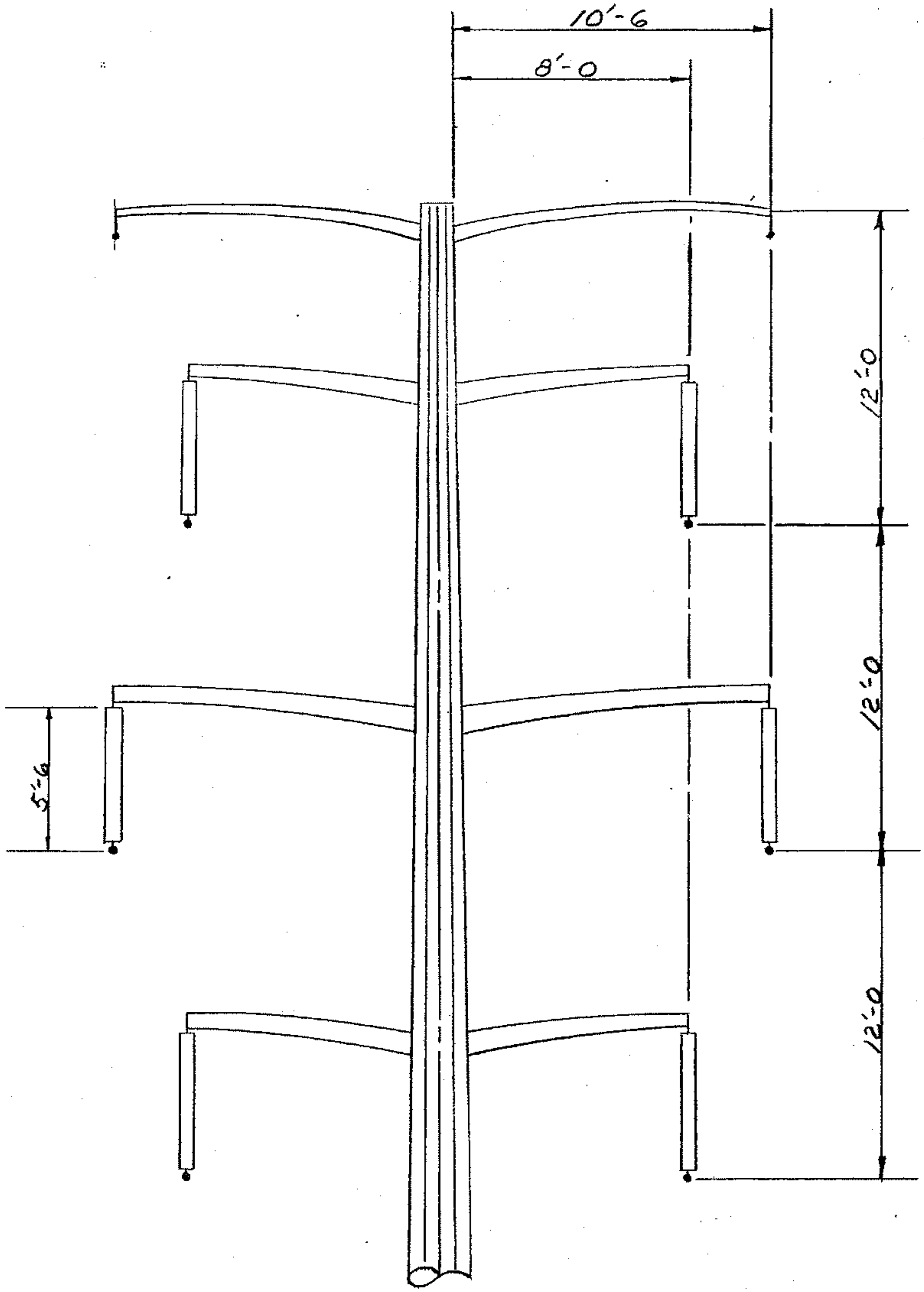

Note: The drawing shown is for a 345KV circuit.
(Source: CL&P)

# Typical 345 kV Overhead Steel Pole with Delta Configuration



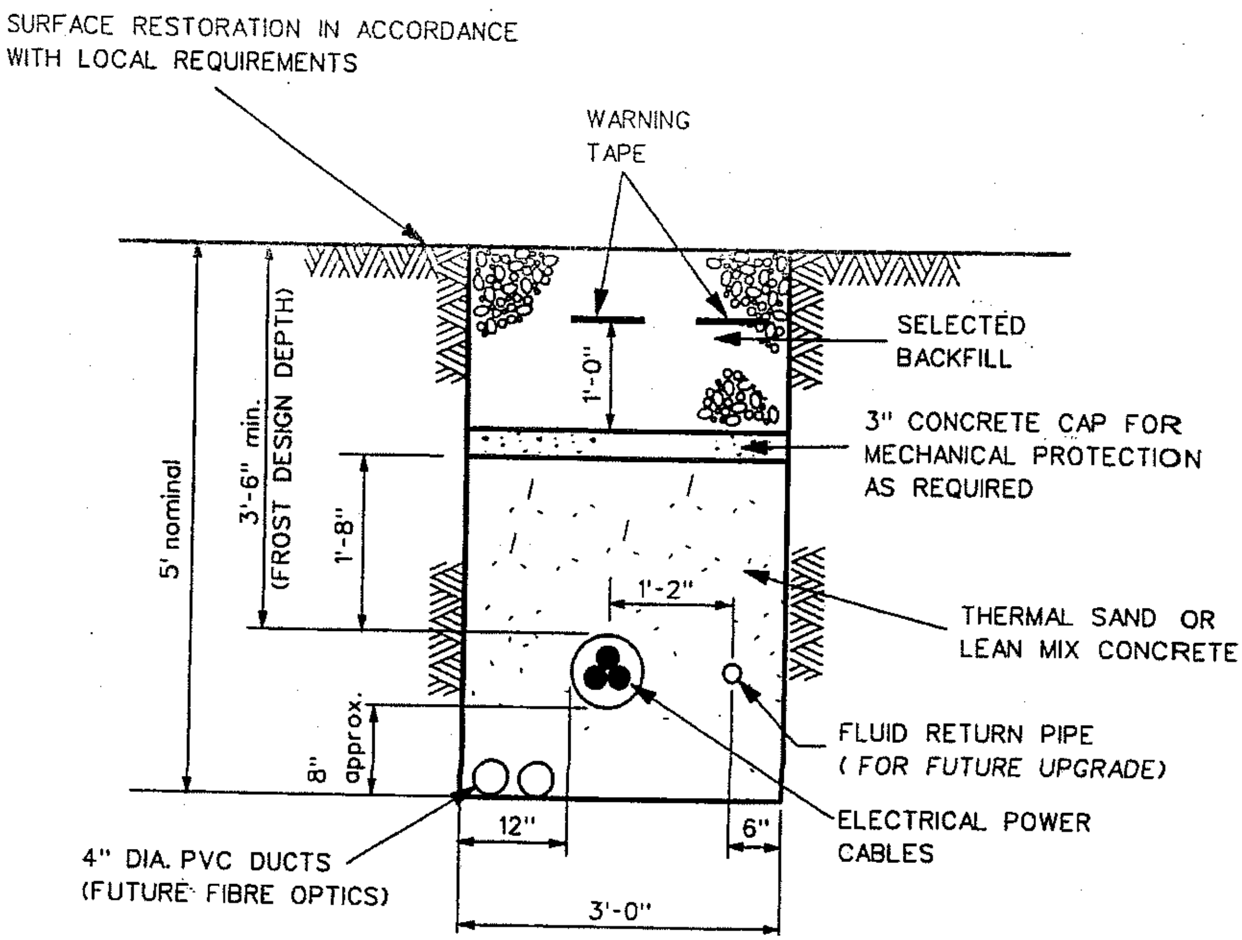

(Source: CL&P)

# Typical 115 kV Overhead Steel Pole Double-Circuit



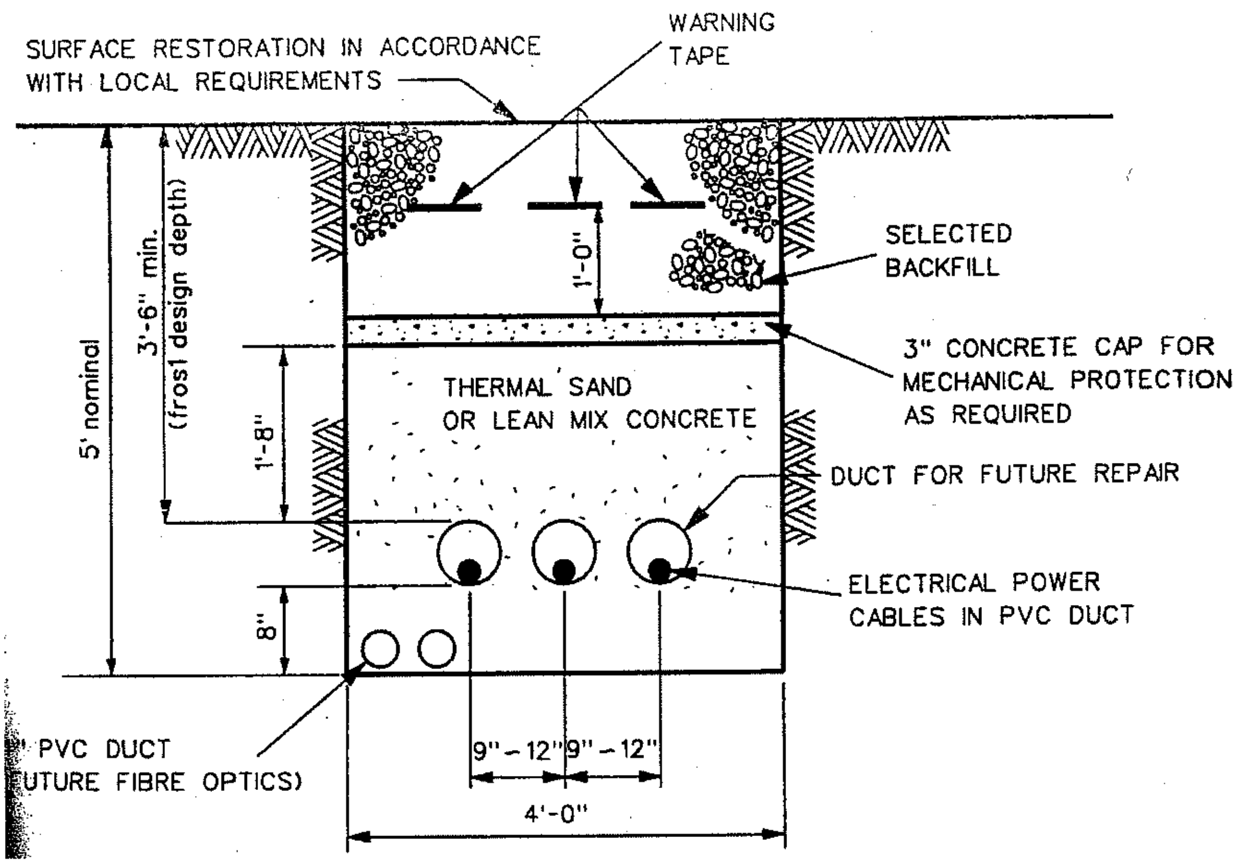

(Source: CL&P)

## Typical Underground HPFF Cable Installation



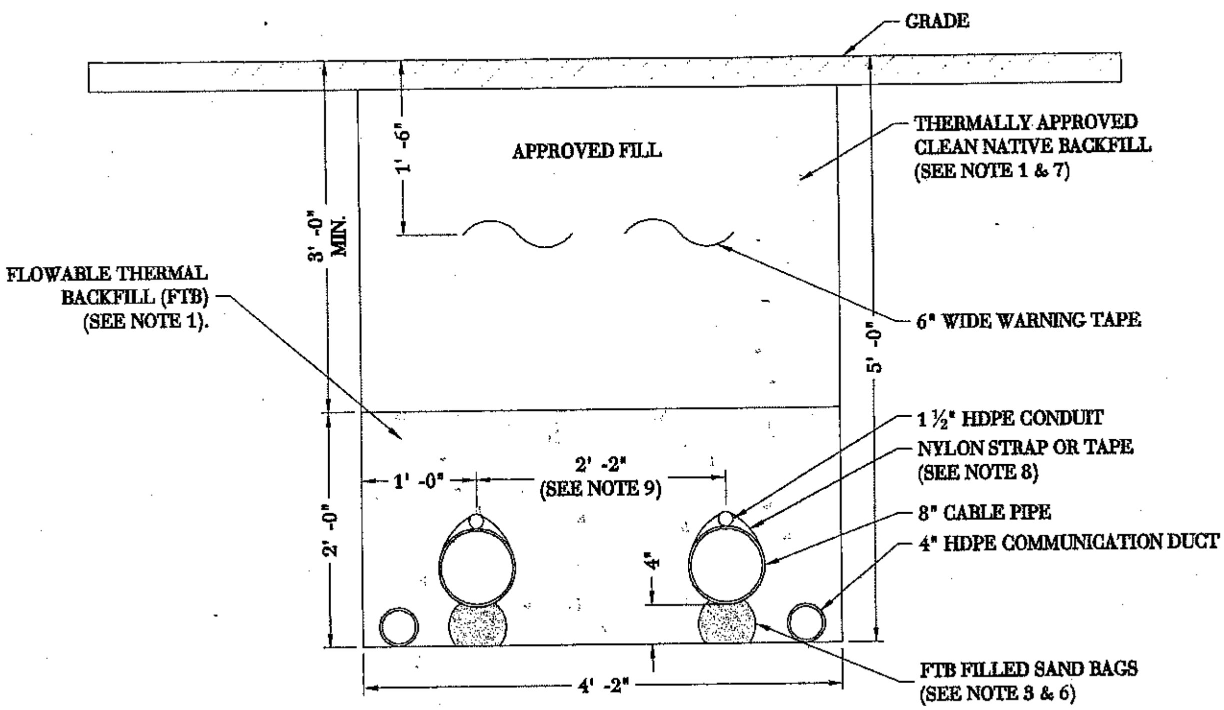

Note: The drawing shown is for a 115 kV circuit.
(Source: CL&P)

# Typical Underground XLPE Cable Installation



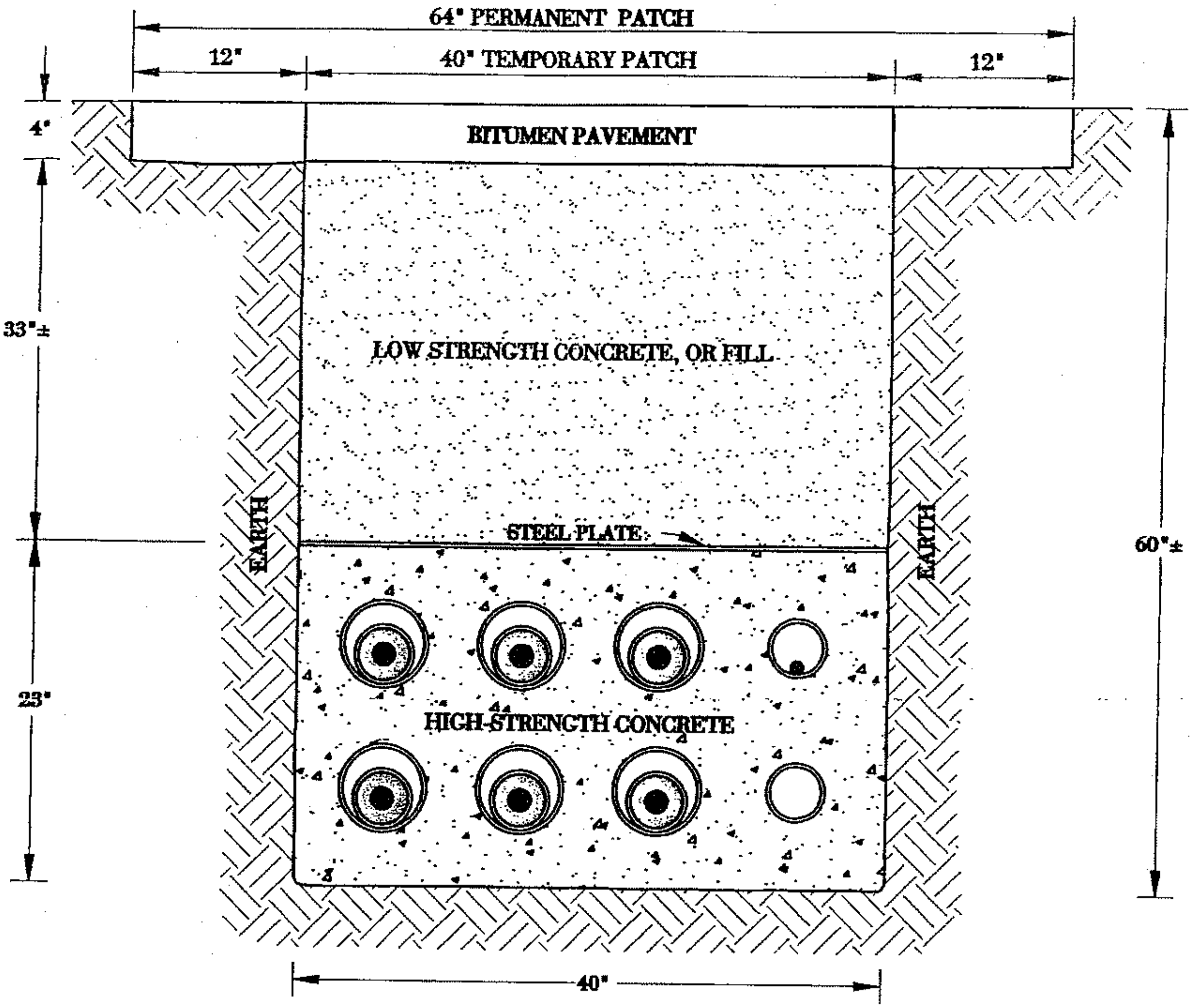

Note: The drawing shown is for a 115 kV circuit
(Source: CL&P)

## Typical Underground HPFF Double-Circuit Cable Installation




Note: The drawing shown is for a 345 kV circuit.
(Source: CL&P)

## Typical Underground XLPE Double-Circuit Cable Installation




Note: The drawing shown is for a 345KV circuit.
(Source: CL&P)

# Appendix B – Life-Cycle Cost Tables

## Overhead 115kV Wood H-Frame

| First Costs | | Losses | |
|---|---|---|---|
| Poles & Foundations | $615,350 | Conductor | 1272 ACSS |
| Conductor & Hardware | $777,600 | Resistance | 0.0871 ohms/mi |
| Site Work | $961,450 | Peak Line Current | 1000 amps |
| Construction | $135,500 | Load Growth | 2.03% |
| Engineering | $198,924 | Loss Factor | 0.38 |
| Sales Tax | $70,309 | Energy Cost | 100 mils/kWh |
| Admin/PM | $556,267 | Energy Cost Escalation | 5.0% |

| Year | PV Factor | First Costs | Losses | O&M | PV Cost | Cum PV |
|---|---|---|---|---|---|---|
| 1 | 0.93 | $432,844 | $88,054 | $4,594 | $525,492 | $525,492 |
| 2 | 0.86 | $400,781 | $89,119 | $4,424 | $494,324 | $1,019,816 |
| 3 | 0.79 | $371,094 | $90,197 | $4,260 | $465,551 | $1,485,367 |
| 4 | 0.74 | $343,605 | $91,288 | $4,102 | $438,996 | $1,924,363 |
| 5 | 0.68 | $318,153 | $92,392 | $3,951 | $414,495 | $2,338,858 |
| 6 | 0.63 | $294,586 | $93,509 | $3,804 | $391,900 | $2,730,758 |
| 7 | 0.58 | $272,765 | $94,640 | $3,663 | $371,069 | $3,101,827 |
| 8 | 0.54 | $252,560 | $95,785 | $3,528 | $351,873 | $3,453,699 |
| 9 | 0.50 | $233,852 | $96,943 | $3,397 | $334,193 | $3,787,892 |
| 10 | 0.46 | $216,530 | $98,116 | $3,271 | $317,917 | $4,105,809 |
| 11 | 0.43 | $200,490 | $99,303 | $3,150 | $302,943 | $4,408,752 |
| 12 | 0.40 | $185,639 | $100,504 | $3,033 | $289,176 | $4,697,929 |
| 13 | 0.37 | $171,888 | $101,719 | $2,921 | $276,529 | $4,974,457 |
| 14 | 0.34 | $159,156 | $102,950 | $2,813 | $264,918 | $5,239,376 |
| 15 | 0.32 | $147,366 | $104,195 | $2,709 | $254,270 | $5,493,646 |
| 16 | 0.29 | $136,450 | $105,455 | $2,608 | $244,514 | $5,738,160 |
| 17 | 0.27 | $126,343 | $106,731 | $2,512 | $235,585 | $5,973,745 |
| 18 | 0.25 | $116,984 | $108,022 | $2,419 | $227,425 | $6,201,169 |
| 19 | 0.23 | $108,319 | $109,328 | $2,329 | $219,976 | $6,421,145 |
| 20 | 0.21 | $100,295 | $110,650 | $2,243 | $213,188 | $6,634,334 |
| 21 | 0.20 | $92,866 | $111,989 | $2,160 | $207,014 | $6,841,348 |
| 22 | 0.18 | $85,987 | $113,343 | $2,080 | $201,410 | $7,042,758 |
| 23 | 0.17 | $79,618 | $114,714 | $2,003 | $196,334 | $7,239,093 |
| 24 | 0.16 | $73,720 | $116,102 | $1,929 | $191,750 | $7,430,843 |
| 25 | 0.15 | $68,259 | $117,506 | $1,857 | $187,622 | $7,618,465 |
| 26 | 0.14 | $63,203 | $118,927 | $1,788 | $183,918 | $7,802,384 |
| 27 | 0.13 | $58,521 | $120,366 | $1,722 | $180,609 | $7,982,993 |
| 28 | 0.12 | $54,186 | $121,821 | $1,658 | $177,666 | $8,160,659 |
| 29 | 0.11 | $50,173 | $123,295 | $1,597 | $175,064 | $8,335,723 |
| 30 | 0.10 | $46,456 | $124,786 | $1,538 | $172,780 | $8,508,503 |
| 31 | 0.09 | $43,015 | $126,295 | $1,481 | $170,791 | $8,679,294 |
| 32 | 0.09 | $39,829 | $127,823 | $1,426 | $169,078 | $8,848,372 |
| 33 | 0.08 | $36,878 | $129,369 | $1,373 | $167,620 | $9,015,992 |
| 34 | 0.07 | $34,147 | $130,934 | $1,322 | $166,403 | $9,182,395 |
| 35 | 0.07 | $31,617 | $132,517 | $1,273 | $165,408 | $9,347,803 |
| 36 | 0.06 | $29,275 | $134,120 | $1,226 | $164,622 | $9,512,424 |
| 37 | 0.06 | $27,107 | $135,742 | $1,181 | $164,030 | $9,676,454 |
| 38 | 0.05 | $25,099 | $137,384 | $1,137 | $163,620 | $9,840,074 |
| 39 | 0.05 | $23,240 | $139,046 | $1,095 | $163,380 | $10,003,455 |
| 40 | 0.05 | $21,518 | $140,728 | $1,054 | $163,300 | $10,166,755 |

## Overhead 115kV Steel Delta

| First Costs | | Losses | |
|---|---|---|---|
| Poles & Foundations | $1,457,321 | Conductor | 1272 ACSS |
| Conductor & Hardware | $838,874 | Resistance | 0.0871 ohms/mi |
| Site Work | $1,476,882 | Peak Line Current | 1000 amps |
| Construction | $136,536 | Load Growth | 2.03% |
| Engineering | $487,100 | Loss Factor | 0.38 |
| Sales Tax | $111,906 | Energy Cost | 100 mils/kWh |
| Admin/PM | $362,381 | Energy Cost Escalation | 5.0% |

| Year | PV Factor | First Costs | Losses | O&M | PV Cost | Cum PV |
|---|---|---|---|---|---|---|
| 1 | 0.93 | $635,936 | $88,054 | $4,594 | $728,584 | $728,584 |
| 2 | 0.86 | $588,830 | $89,119 | $4,424 | $682,373 | $1,410,957 |
| 3 | 0.79 | $545,213 | $90,197 | $4,260 | $639,670 | $2,050,626 |
| 4 | 0.74 | $504,827 | $91,288 | $4,102 | $600,217 | $2,650,843 |
| 5 | 0.68 | $467,432 | $92,392 | $3,951 | $563,774 | $3,214,618 |
| 6 | 0.63 | $432,807 | $93,509 | $3,804 | $530,121 | $3,744,738 |
| 7 | 0.58 | $400,748 | $94,640 | $3,663 | $499,051 | $4,243,790 |
| 8 | 0.54 | $371,063 | $95,785 | $3,528 | $470,375 | $4,714,165 |
| 9 | 0.50 | $343,576 | $96,943 | $3,397 | $443,917 | $5,158,082 |
| 10 | 0.46 | $318,126 | $98,116 | $3,271 | $419,514 | $5,577,595 |
| 11 | 0.43 | $294,561 | $99,303 | $3,150 | $397,014 | $5,974,610 |
| 12 | 0.40 | $272,742 | $100,504 | $3,033 | $376,279 | $6,350,889 |
| 13 | 0.37 | $252,539 | $101,719 | $2,921 | $357,179 | $6,708,068 |
| 14 | 0.34 | $233,832 | $102,950 | $2,813 | $339,595 | $7,047,663 |
| 15 | 0.32 | $216,511 | $104,195 | $2,709 | $323,415 | $7,371,078 |
| 16 | 0.29 | $200,474 | $105,455 | $2,608 | $308,537 | $7,679,615 |
| 17 | 0.27 | $185,624 | $106,731 | $2,512 | $294,866 | $7,974,481 |
| 18 | 0.25 | $171,874 | $108,022 | $2,419 | $282,314 | $8,256,795 |
| 19 | 0.23 | $159,142 | $109,328 | $2,329 | $270,800 | $8,527,595 |
| 20 | 0.21 | $147,354 | $110,650 | $2,243 | $260,247 | $8,787,842 |
| 21 | 0.20 | $136,439 | $111,989 | $2,160 | $250,587 | $9,038,430 |
| 22 | 0.18 | $126,332 | $113,343 | $2,080 | $241,755 | $9,280,185 |
| 23 | 0.17 | $116,974 | $114,714 | $2,003 | $233,691 | $9,513,877 |
| 24 | 0.16 | $108,310 | $116,102 | $1,929 | $226,340 | $9,740,216 |
| 25 | 0.15 | $100,287 | $117,506 | $1,857 | $219,650 | $9,959,866 |
| 26 | 0.14 | $92,858 | $118,927 | $1,788 | $213,574 | $10,173,440 |
| 27 | 0.13 | $85,980 | $120,366 | $1,722 | $208,067 | $10,381,507 |
| 28 | 0.12 | $79,611 | $121,821 | $1,658 | $203,091 | $10,584,598 |
| 29 | 0.11 | $73,714 | $123,295 | $1,597 | $198,606 | $10,783,203 |
| 30 | 0.10 | $68,253 | $124,786 | $1,538 | $194,577 | $10,977,781 |
| 31 | 0.09 | $63,198 | $126,295 | $1,481 | $190,974 | $11,168,755 |
| 32 | 0.09 | $58,516 | $127,823 | $1,426 | $187,765 | $11,356,520 |
| 33 | 0.08 | $54,182 | $129,369 | $1,373 | $184,924 | $11,541,444 |
| 34 | 0.07 | $50,168 | $130,934 | $1,322 | $182,424 | $11,723,868 |
| 35 | 0.07 | $46,452 | $132,517 | $1,273 | $180,243 | $11,904,111 |
| 36 | 0.06 | $43,011 | $134,120 | $1,226 | $178,358 | $12,082,469 |
| 37 | 0.06 | $39,825 | $135,742 | $1,181 | $176,748 | $12,259,217 |
| 38 | 0.05 | $36,875 | $137,384 | $1,137 | $175,396 | $12,434,614 |
| 39 | 0.05 | $34,144 | $139,046 | $1,095 | $174,285 | $12,608,898 |
| 40 | 0.05 | $31,615 | $140,728 | $1,054 | $173,397 | $12,782,295 |

## Overhead 115kV Steel Double-Circuit

| First Costs | | Losses | |
|---|---|---|---|
| Poles & Foundations | $2,312,107 | Conductor | 1272 ACSS |
| Conductor & Hardware | $1,586,986 | Resistance | 0.0871 ohms/mi |
| Site Work | $1,572,621 | Peak Line Current | 1000 amps |
| Construction | $147,947 | Load Growth | 2.03% |
| Engineering | $338,070 | Loss Factor | 0.38 |
| Sales Tax | $186,164 | Energy Cost | 100 mils/kWh |
| Admin/PM | $617,504 | Energy Cost Escalation | 5.0% |

| Year | PV Factor | First Costs | Losses | O&M | PV Cost | Cum PV |
|---|---|---|---|---|---|---|
| 1 | 0.93 | $882,738 | $88,054 | $4,594 | $975,386 | $975,386 |
| 2 | 0.86 | $817,350 | $89,119 | $4,424 | $910,893 | $1,886,279 |
| 3 | 0.79 | $756,806 | $90,197 | $4,260 | $851,263 | $2,737,542 |
| 4 | 0.74 | $700,746 | $91,288 | $4,102 | $796,136 | $3,533,678 |
| 5 | 0.68 | $648,839 | $92,392 | $3,951 | $745,181 | $4,278,859 |
| 6 | 0.63 | $600,777 | $93,509 | $3,804 | $698,090 | $4,976,950 |
| 7 | 0.58 | $556,275 | $94,640 | $3,663 | $654,578 | $5,631,528 |
| 8 | 0.54 | $515,069 | $95,785 | $3,528 | $614,382 | $6,245,910 |
| 9 | 0.50 | $476,916 | $96,943 | $3,397 | $577,256 | $6,823,166 |
| 10 | 0.46 | $441,589 | $98,116 | $3,271 | $542,976 | $7,366,142 |
| 11 | 0.43 | $408,879 | $99,303 | $3,150 | $511,331 | $7,877,474 |
| 12 | 0.40 | $378,591 | $100,504 | $3,033 | $482,128 | $8,359,602 |
| 13 | 0.37 | $350,547 | $101,719 | $2,921 | $455,188 | $8,814,790 |
| 14 | 0.34 | $324,581 | $102,950 | $2,813 | $430,344 | $9,245,134 |
| 15 | 0.32 | $300,538 | $104,195 | $2,709 | $407,442 | $9,652,575 |
| 16 | 0.29 | $278,276 | $105,455 | $2,608 | $386,339 | $10,038,915 |
| 17 | 0.27 | $257,663 | $106,731 | $2,512 | $366,905 | $10,405,820 |
| 18 | 0.25 | $238,577 | $108,022 | $2,419 | $349,017 | $10,754,837 |
| 19 | 0.23 | $220,904 | $109,328 | $2,329 | $332,562 | $11,087,398 |
| 20 | 0.21 | $204,541 | $110,650 | $2,243 | $317,434 | $11,404,833 |
| 21 | 0.20 | $189,390 | $111,989 | $2,160 | $303,538 | $11,708,371 |
| 22 | 0.18 | $175,361 | $113,343 | $2,080 | $290,784 | $11,999,155 |
| 23 | 0.17 | $162,371 | $114,714 | $2,003 | $279,088 | $12,278,244 |
| 24 | 0.16 | $150,344 | $116,102 | $1,929 | $268,374 | $12,546,618 |
| 25 | 0.15 | $139,207 | $117,506 | $1,857 | $258,570 | $12,805,188 |
| 26 | 0.14 | $128,896 | $118,927 | $1,788 | $249,611 | $13,054,799 |
| 27 | 0.13 | $119,348 | $120,366 | $1,722 | $241,435 | $13,296,234 |
| 28 | 0.12 | $110,507 | $121,821 | $1,658 | $233,987 | $13,530,221 |
| 29 | 0.11 | $102,321 | $123,295 | $1,597 | $227,213 | $13,757,435 |
| 30 | 0.10 | $94,742 | $124,786 | $1,538 | $221,066 | $13,978,501 |
| 31 | 0.09 | $87,724 | $126,295 | $1,481 | $215,500 | $14,194,001 |
| 32 | 0.09 | $81,226 | $127,823 | $1,426 | $210,475 | $14,404,476 |
| 33 | 0.08 | $75,209 | $129,369 | $1,373 | $205,952 | $14,610,428 |
| 34 | 0.07 | $69,638 | $130,934 | $1,322 | $201,894 | $14,812,322 |
| 35 | 0.07 | $64,480 | $132,517 | $1,273 | $198,271 | $15,010,593 |
| 36 | 0.06 | $59,704 | $134,120 | $1,226 | $195,050 | $15,205,643 |
| 37 | 0.06 | $55,281 | $135,742 | $1,181 | $192,204 | $15,397,847 |
| 38 | 0.05 | $51,186 | $137,384 | $1,137 | $189,707 | $15,587,554 |
| 39 | 0.05 | $47,395 | $139,046 | $1,095 | $187,535 | $15,775,090 |
| 40 | 0.05 | $43,884 | $140,728 | $1,054 | $185,666 | $15,960,756 |

## Overhead 345kV Wood 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 | | 1000 amps |
| Construction | $136,150 | Load Growth | | 2.03% |
| Engineering | $271,060 | Loss Factor | | 0.38 |
| Sales Tax | $136,411 | Energy Cost | | 100 mils/kWh |
| Admin/PM | $600,029 | Energy Cost Escalation | | 5.0% |

| Year | PV Factor | First Costs | Losses | O&M | PV Cost | Cum PV |
|---|---|---|---|---|---|---|
| 1 | 0.93 | $707,768 | $35,755 | $4,594 | $748,117 | $748,117 |
| 2 | 0.86 | $655,341 | $36,188 | $4,424 | $695,952 | $1,444,069 |
| 3 | 0.79 | $606,797 | $36,625 | $4,260 | $647,682 | $2,091,752 |
| 4 | 0.74 | $561,849 | $37,068 | $4,102 | $603,020 | $2,694,772 |
| 5 | 0.68 | $520,230 | $37,517 | $3,951 | $561,698 | $3,256,469 |
| 6 | 0.63 | $481,695 | $37,970 | $3,804 | $523,469 | $3,779,939 |
| 7 | 0.58 | $446,014 | $38,430 | $3,663 | $488,107 | $4,268,045 |
| 8 | 0.54 | $412,976 | $38,895 | $3,528 | $455,398 | $4,723,443 |
| 9 | 0.50 | $382,385 | $39,365 | $3,397 | $425,147 | $5,148,590 |
| 10 | 0.46 | $354,060 | $39,841 | $3,271 | $397,172 | $5,545,762 |
| 11 | 0.43 | $327,833 | $40,323 | $3,150 | $371,306 | $5,917,069 |
| 12 | 0.40 | $303,549 | $40,811 | $3,033 | $347,393 | $6,264,462 |
| 13 | 0.37 | $281,064 | $41,304 | $2,921 | $325,290 | $6,589,752 |
| 14 | 0.34 | $260,245 | $41,804 | $2,813 | $304,861 | $6,894,613 |
| 15 | 0.32 | $240,967 | $42,309 | $2,709 | $285,985 | $7,180,598 |
| 16 | 0.29 | $223,118 | $42,821 | $2,608 | $268,547 | $7,449,146 |
| 17 | 0.27 | $206,591 | $43,339 | $2,512 | $252,441 | $7,701,587 |
| 18 | 0.25 | $191,288 | $43,863 | $2,419 | $237,570 | $7,939,157 |
| 19 | 0.23 | $177,118 | $44,394 | $2,329 | $223,841 | $8,162,998 |
| 20 | 0.21 | $163,998 | $44,931 | $2,243 | $211,172 | $8,374,170 |
| 21 | 0.20 | $151,850 | $45,474 | $2,160 | $199,484 | $8,573,654 |
| 22 | 0.18 | $140,602 | $46,024 | $2,080 | $188,706 | $8,762,361 |
| 23 | 0.17 | $130,187 | $46,581 | $2,003 | $178,771 | $8,941,131 |
| 24 | 0.16 | $120,544 | $47,144 | $1,929 | $169,617 | $9,110,748 |
| 25 | 0.15 | $111,615 | $47,715 | $1,857 | $161,186 | $9,271,934 |
| 26 | 0.14 | $103,347 | $48,292 | $1,788 | $153,427 | $9,425,361 |
| 27 | 0.13 | $95,691 | $48,876 | $1,722 | $146,289 | $9,571,650 |
| 28 | 0.12 | $88,603 | $49,467 | $1,658 | $139,728 | $9,711,379 |
| 29 | 0.11 | $82,040 | $50,065 | $1,597 | $133,702 | $9,845,081 |
| 30 | 0.10 | $75,963 | $50,671 | $1,538 | $128,171 | $9,973,252 |
| 31 | 0.09 | $70,336 | $51,284 | $1,481 | $123,100 | $10,096,353 |
| 32 | 0.09 | $65,126 | $51,904 | $1,426 | $118,456 | $10,214,809 |
| 33 | 0.08 | $60,302 | $52,532 | $1,373 | $114,207 | $10,329,015 |
| 34 | 0.07 | $55,835 | $53,167 | $1,322 | $110,324 | $10,439,340 |
| 35 | 0.07 | $51,699 | $53,810 | $1,273 | $106,783 | $10,546,122 |
| 36 | 0.06 | $47,870 | $54,461 | $1,226 | $103,557 | $10,649,679 |
| 37 | 0.06 | $44,324 | $55,120 | $1,181 | $100,624 | $10,750,303 |
| 38 | 0.05 | $41,040 | $55,786 | $1,137 | $97,964 | $10,848,267 |
| 39 | 0.05 | $38,000 | $56,461 | $1,095 | $95,556 | $10,943,823 |
| 40 | 0.05 | $35,186 | $57,144 | $1,054 | $93,384 | $11,037,207 |

## Overhead 345kV 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 | | 1000 amps |
| Construction | $147,350 | Load Growth | | 2.03% |
| Engineering | $385,740 | Loss Factor | | 0.38 |
| Sales Tax | $219,721 | Energy Cost | | 100 mils/kWh |
| Admin/PM | $637,489 | Energy Cost Escalation | | 5.0% |

| Year | PV Factor | First Costs | Loss | O&M | PV Cost | Cum PV |
|---|---|---|---|---|---|---|
| 1 | 0.93 | $1,007,210 | $35,755 | $4,594 | $1,047,559 | $1,047,559 |
| 2 | 0.86 | $932,602 | $36,188 | $4,424 | $973,214 | $2,020,773 |
| 3 | 0.79 | $863,520 | $36,625 | $4,260 | $904,406 | $2,925,179 |
| 4 | 0.74 | $799,556 | $37,068 | $4,102 | $840,727 | $3,765,905 |
| 5 | 0.68 | $740,329 | $37,517 | $3,951 | $781,797 | $4,547,702 |
| 6 | 0.63 | $685,490 | $37,970 | $3,804 | $727,265 | $5,274,967 |
| 7 | 0.58 | $634,713 | $38,430 | $3,663 | $676,806 | $5,951,773 |
| 8 | 0.54 | $587,697 | $38,895 | $3,528 | $630,119 | $6,581,892 |
| 9 | 0.50 | $544,164 | $39,365 | $3,397 | $586,926 | $7,168,819 |
| 10 | 0.46 | $503,856 | $39,841 | $3,271 | $546,968 | $7,715,787 |
| 11 | 0.43 | $466,533 | $40,323 | $3,150 | $510,006 | $8,225,793 |
| 12 | 0.40 | $431,975 | $40,811 | $3,033 | $475,819 | $8,701,612 |
| 13 | 0.37 | $399,977 | $41,304 | $2,921 | $444,202 | $9,145,814 |
| 14 | 0.34 | $370,349 | $41,804 | $2,813 | $414,966 | $9,560,780 |
| 15 | 0.32 | $342,916 | $42,309 | $2,709 | $387,934 | $9,948,713 |
| 16 | 0.29 | $317,515 | $42,821 | $2,608 | $362,944 | $10,311,657 |
| 17 | 0.27 | $293,995 | $43,339 | $2,512 | $339,846 | $10,651,503 |
| 18 | 0.25 | $272,218 | $43,863 | $2,419 | $318,500 | $10,970,003 |
| 19 | 0.23 | $252,053 | $44,394 | $2,329 | $298,776 | $11,268,779 |
| 20 | 0.21 | $233,383 | $44,931 | $2,243 | $280,556 | $11,549,335 |
| 21 | 0.20 | $216,095 | $45,474 | $2,160 | $263,729 | $11,813,065 |
| 22 | 0.18 | $200,088 | $46,024 | $2,080 | $248,192 | $12,061,257 |
| 23 | 0.17 | $185,267 | $46,581 | $2,003 | $233,850 | $12,295,107 |
| 24 | 0.16 | $171,543 | $47,144 | $1,929 | $220,616 | $12,515,723 |
| 25 | 0.15 | $158,836 | $47,715 | $1,857 | $208,408 | $12,724,131 |
| 26 | 0.14 | $147,071 | $48,292 | $1,788 | $197,151 | $12,921,282 |
| 27 | 0.13 | $136,177 | $48,876 | $1,722 | $186,774 | $13,108,056 |
| 28 | 0.12 | $126,089 | $49,467 | $1,658 | $177,215 | $13,285,271 |
| 29 | 0.11 | $116,749 | $50,065 | $1,597 | $168,412 | $13,453,682 |
| 30 | 0.10 | $108,101 | $50,671 | $1,538 | $160,310 | $13,613,992 |
| 31 | 0.09 | $100,094 | $51,284 | $1,481 | $152,858 | $13,766,851 |
| 32 | 0.09 | $92,679 | $51,904 | $1,426 | $146,009 | $13,912,860 |
| 33 | 0.08 | $85,814 | $52,532 | $1,373 | $139,719 | $14,052,579 |
| 34 | 0.07 | $79,458 | $53,167 | $1,322 | $133,947 | $14,186,526 |
| 35 | 0.07 | $73,572 | $53,810 | $1,273 | $128,655 | $14,315,181 |
| 36 | 0.06 | $68,122 | $54,461 | $1,226 | $123,809 | $14,438,991 |
| 37 | 0.06 | $63,076 | $55,120 | $1,181 | $119,376 | $14,558,367 |
| 38 | 0.05 | $58,404 | $55,786 | $1,137 | $115,327 | $14,673,694 |
| 39 | 0.05 | $54,078 | $56,461 | $1,095 | $111,634 | $14,785,328 |
| 40 | 0.05 | $50,072 | $57,144 | $1,054 | $108,270 | $14,893,598 |

## Underground 115kV 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 | | 1000 amps |
| Construction | $299,414 | Load Growth | | 2.03% |
| Engineering | $374,267 | Loss Factor | | 0.38 |
| Sales Tax | $468,283 | Energy Cost | | 100 mils/kWh |
| Admin/PM | $1,253,345 | Energy Cost Escalation | | 5.0% |

| Year | PV Factor | First Costs | Loss | O&M | PV Cost | Cum PV |
|---|---|---|---|---|---|---|
| 1 | 0.93 | $1,954,505 | $32,052 | $8,415 | $1,994,972 | $1,994,972 |
| 2 | 0.86 | $1,809,727 | $32,440 | $8,104 | $1,850,270 | $3,845,242 |
| 3 | 0.79 | $1,675,673 | $32,832 | $7,804 | $1,716,308 | $5,561,551 |
| 4 | 0.74 | $1,551,549 | $33,229 | $7,514 | $1,592,293 | $7,153,843 |
| 5 | 0.68 | $1,436,620 | $33,631 | $7,236 | $1,477,487 | $8,631,330 |
| 6 | 0.63 | $1,330,203 | $34,038 | $6,968 | $1,371,209 | $10,002,539 |
| 7 | 0.58 | $1,231,670 | $34,449 | $6,710 | $1,272,829 | $11,275,368 |
| 8 | 0.54 | $1,140,435 | $34,866 | $6,462 | $1,181,763 | $12,457,131 |
| 9 | 0.50 | $1,055,958 | $35,288 | $6,222 | $1,097,468 | $13,554,599 |
| 10 | 0.46 | $977,739 | $35,715 | $5,992 | $1,019,445 | $14,574,045 |
| 11 | 0.43 | $905,314 | $36,147 | $5,770 | $947,230 | $15,521,275 |
| 12 | 0.40 | $838,254 | $36,584 | $5,556 | $880,394 | $16,401,669 |
| 13 | 0.37 | $776,161 | $37,026 | $5,350 | $818,537 | $17,220,206 |
| 14 | 0.34 | $718,667 | $37,474 | $5,152 | $761,294 | $17,981,500 |
| 15 | 0.32 | $665,433 | $37,927 | $4,961 | $708,322 | $18,689,821 |
| 16 | 0.29 | $616,142 | $38,386 | $4,778 | $659,305 | $19,349,126 |
| 17 | 0.27 | $570,501 | $38,850 | $4,601 | $613,952 | $19,963,079 |
| 18 | 0.25 | $528,242 | $39,320 | $4,430 | $571,993 | $20,535,071 |
| 19 | 0.23 | $489,113 | $39,796 | $4,266 | $533,175 | $21,068,246 |
| 20 | 0.21 | $452,882 | $40,277 | $4,108 | $497,268 | $21,565,514 |
| 21 | 0.20 | $419,336 | $40,764 | $3,956 | $464,056 | $22,029,570 |
| 22 | 0.18 | $388,274 | $41,257 | $3,810 | $433,341 | $22,462,910 |
| 23 | 0.17 | $359,513 | $41,756 | $3,668 | $404,937 | $22,867,848 |
| 24 | 0.16 | $332,882 | $42,261 | $3,533 | $378,676 | $23,246,524 |
| 25 | 0.15 | $308,224 | $42,773 | $3,402 | $354,398 | $23,600,922 |
| 26 | 0.14 | $285,393 | $43,290 | $3,276 | $331,958 | $23,932,880 |
| 27 | 0.13 | $264,253 | $43,813 | $3,154 | $311,220 | $24,244,101 |
| 28 | 0.12 | $244,678 | $44,343 | $3,038 | $292,059 | $24,536,160 |
| 29 | 0.11 | $226,554 | $44,880 | $2,925 | $274,359 | $24,810,519 |
| 30 | 0.10 | $209,772 | $45,423 | $2,817 | $258,011 | $25,068,530 |
| 31 | 0.09 | $194,233 | $45,972 | $2,712 | $242,918 | $25,311,448 |
| 32 | 0.09 | $179,846 | $46,528 | $2,612 | $228,986 | $25,540,434 |
| 33 | 0.08 | $166,524 | $47,091 | $2,515 | $216,130 | $25,756,564 |
| 34 | 0.07 | $154,189 | $47,660 | $2,422 | $204,271 | $25,960,835 |
| 35 | 0.07 | $142,767 | $48,237 | $2,332 | $193,337 | $26,154,172 |
| 36 | 0.06 | $132,192 | $48,820 | $2,246 | $183,258 | $26,337,430 |
| 37 | 0.06 | $122,400 | $49,411 | $2,163 | $173,974 | $26,511,403 |
| 38 | 0.05 | $113,333 | $50,008 | $2,083 | $165,424 | $26,676,828 |
| 39 | 0.05 | $104,938 | $50,613 | $2,006 | $157,557 | $26,834,385 |
| 40 | 0.05 | $97,165 | $51,225 | $1,931 | $150,322 | $26,984,706 |

## Underground 115kV XLPE

| First Costs | | Losses | |
|---|---|---|---|
| Ducts & Vaults | $6,009,792 | Cable | 3000 kcmil |
| | | | 0.0268 |
| Cable & Hardware | $6,573,210 | Resistance | ohms/mi |
| Site Work | $3,004,896 | Peak Line Current | 1000 amps |
| Construction | $375,612 | Load Growth | 2.03% |
| Engineering | $469,515 | Loss Factor | 0.38 |
| Sales Tax | $596,096 | Energy Cost | 100 mils/kWh |
| Admin/PM | $1,751,479 | Energy Cost Escalation | 5.0% |

| Year | PV Factor | First Costs | Losses | O&M | PV Cost | Cum PV |
|---|---|---|---|---|---|---|
| 1 | 0.93 | $2,451,912 | $27,088 | $8,415 | $2,487,414 | $2,487,414 |
| 2 | 0.86 | $2,270,289 | $27,415 | $8,104 | $2,305,807 | $4,793,222 |
| 3 | 0.79 | $2,102,119 | $27,747 | $7,804 | $2,137,669 | $6,930,891 |
| 4 | 0.74 | $1,946,407 | $28,082 | $7,514 | $1,982,003 | $8,912,894 |
| 5 | 0.68 | $1,802,228 | $28,422 | $7,236 | $1,837,886 | $10,750,781 |
| 6 | 0.63 | $1,668,730 | $28,766 | $6,968 | $1,704,464 | $12,455,245 |
| 7 | 0.58 | $1,545,120 | $29,114 | $6,710 | $1,580,944 | $14,036,189 |
| 8 | 0.54 | $1,430,667 | $29,466 | $6,462 | $1,466,594 | $15,502,783 |
| 9 | 0.50 | $1,324,692 | $29,822 | $6,222 | $1,360,736 | $16,863,519 |
| 10 | 0.46 | $1,226,566 | $30,183 | $5,992 | $1,262,741 | $18,126,260 |
| 11 | 0.43 | $1,135,710 | $30,548 | $5,770 | $1,172,027 | $19,298,287 |
| 12 | 0.40 | $1,051,583 | $30,917 | $5,556 | $1,088,056 | $20,386,344 |
| 13 | 0.37 | $973,688 | $31,291 | $5,350 | $1,010,330 | $21,396,673 |
| 14 | 0.34 | $901,563 | $31,670 | $5,152 | $938,385 | $22,335,058 |
| 15 | 0.32 | $834,780 | $32,053 | $4,961 | $871,795 | $23,206,853 |
| 16 | 0.29 | $772,945 | $32,441 | $4,778 | $810,163 | $24,017,016 |
| 17 | 0.27 | $715,690 | $32,833 | $4,601 | $753,123 | $24,770,139 |
| 18 | 0.25 | $662,676 | $33,230 | $4,430 | $700,336 | $25,470,475 |
| 19 | 0.23 | $613,589 | $33,632 | $4,266 | $651,487 | $26,121,962 |
| 20 | 0.21 | $568,138 | $34,039 | $4,108 | $606,285 | $26,728,247 |
| 21 | 0.20 | $526,053 | $34,450 | $3,956 | $564,460 | $27,292,706 |
| 22 | 0.18 | $487,086 | $34,867 | $3,810 | $525,763 | $27,818,469 |
| 23 | 0.17 | $451,006 | $35,289 | $3,668 | $489,963 | $28,308,433 |
| 24 | 0.16 | $417,598 | $35,716 | $3,533 | $456,846 | $28,765,279 |
| 25 | 0.15 | $386,665 | $36,148 | $3,402 | $426,214 | $29,191,493 |
| 26 | 0.14 | $358,023 | $36,585 | $3,276 | $397,884 | $29,589,377 |
| 27 | 0.13 | $331,503 | $37,027 | $3,154 | $371,685 | $29,961,061 |
| 28 | 0.12 | $306,947 | $37,475 | $3,038 | $347,460 | $30,308,521 |
| 29 | 0.11 | $284,210 | $37,929 | $2,925 | $325,064 | $30,633,585 |
| 30 | 0.10 | $263,158 | $38,387 | $2,817 | $304,362 | $30,937,947 |
| 31 | 0.09 | $243,664 | $38,852 | $2,712 | $285,228 | $31,223,175 |
| 32 | 0.09 | $225,615 | $39,321 | $2,612 | $267,549 | $31,490,724 |
| 33 | 0.08 | $208,903 | $39,797 | $2,515 | $251,215 | $31,741,939 |
| 34 | 0.07 | $193,429 | $40,278 | $2,422 | $236,129 | $31,978,068 |
| 35 | 0.07 | $179,101 | $40,766 | $2,332 | $222,199 | $32,200,267 |
| 36 | 0.06 | $165,834 | $41,259 | $2,246 | $209,339 | $32,409,605 |
| 37 | 0.06 | $153,550 | $41,758 | $2,163 | $197,470 | $32,607,076 |
| 38 | 0.05 | $142,176 | $42,263 | $2,083 | $186,521 | $32,793,597 |
| 39 | 0.05 | $131,644 | $42,774 | $2,006 | $176,424 | $32,970,021 |
| 40 | 0.05 | $121,893 | $43,291 | $1,931 | $167,115 | $33,137,136 |

## Underground 115kV XLPE Double-Circuit

| First Costs | | Losses | |
|---|---|---|---|
| Ducts & Vaults | $9,242,496 | Cable | 3000 kcmil |
| | | | 0.0268 |
| Cable & Hardware | $10,108,980 | Resistance | ohms/mi |
| Site Work | $4,621,248 | Peak Line Current | 1000 amps |
| Construction | $577,656 | Load Growth | 2.03% |
| Engineering | $866,484 | Loss Factor | 0.38 |
| Sales Tax | $916,740 | Energy Cost | 100 mils/kWh |
| Admin/PM | $2,549,196 | Energy Cost Escalation | 5.0% |

| Year | PV Factor | First Costs | Loss | O&M | PV Cost | Cum PV |
|---|---|---|---|---|---|---|
| 1 | 0.93 | $3,770,810 | $27,088 | $8,415 | $3,806,313 | $3,806,313 |
| 2 | 0.86 | $3,491,491 | $27,415 | $8,104 | $3,527,010 | $7,333,322 |
| 3 | 0.79 | $3,232,862 | $27,747 | $7,804 | $3,268,412 | $10,601,734 |
| 4 | 0.74 | $2,993,391 | $28,082 | $7,514 | $3,028,987 | $13,630,722 |
| 5 | 0.68 | $2,771,658 | $28,422 | $7,236 | $2,807,316 | $16,438,038 |
| 6 | 0.63 | $2,566,350 | $28,766 | $6,968 | $2,602,084 | $19,040,122 |
| 7 | 0.58 | $2,376,250 | $29,114 | $6,710 | $2,412,074 | $21,452,195 |
| 8 | 0.54 | $2,200,231 | $29,466 | $6,462 | $2,236,159 | $23,688,354 |
| 9 | 0.50 | $2,037,251 | $29,822 | $6,222 | $2,073,296 | $25,761,650 |
| 10 | 0.46 | $1,886,344 | $30,183 | $5,992 | $1,922,518 | $27,684,168 |
| 11 | 0.43 | $1,746,615 | $30,548 | $5,770 | $1,782,932 | $29,467,101 |
| 12 | 0.40 | $1,617,236 | $30,917 | $5,556 | $1,653,709 | $31,120,810 |
| 13 | 0.37 | $1,497,441 | $31,291 | $5,350 | $1,534,082 | $32,654,892 |
| 14 | 0.34 | $1,386,519 | $31,670 | $5,152 | $1,423,341 | $34,078,234 |
| 15 | 0.32 | $1,283,814 | $32,053 | $4,961 | $1,320,828 | $35,399,062 |
| 16 | 0.29 | $1,188,717 | $32,441 | $4,778 | $1,225,935 | $36,624,997 |
| 17 | 0.27 | $1,100,663 | $32,833 | $4,601 | $1,138,097 | $37,763,094 |
| 18 | 0.25 | $1,019,133 | $33,230 | $4,430 | $1,056,793 | $38,819,887 |
| 19 | 0.23 | $943,642 | $33,632 | $4,266 | $981,540 | $39,801,427 |
| 20 | 0.21 | $873,742 | $34,039 | $4,108 | $911,889 | $40,713,316 |
| 21 | 0.20 | $809,021 | $34,450 | $3,956 | $847,427 | $41,560,743 |
| 22 | 0.18 | $749,093 | $34,867 | $3,810 | $787,770 | $42,348,513 |
| 23 | 0.17 | $693,605 | $35,289 | $3,668 | $732,562 | $43,081,075 |
| 24 | 0.16 | $642,227 | $35,716 | $3,533 | $681,475 | $43,762,550 |
| 25 | 0.15 | $594,654 | $36,148 | $3,402 | $634,204 | $44,396,753 |
| 26 | 0.14 | $550,606 | $36,585 | $3,276 | $590,466 | $44,987,220 |
| 27 | 0.13 | $509,820 | $37,027 | $3,154 | $550,002 | $45,537,222 |
| 28 | 0.12 | $472,056 | $37,475 | $3,038 | $512,569 | $46,049,790 |
| 29 | 0.11 | $437,089 | $37,929 | $2,925 | $477,942 | $46,527,732 |
| 30 | 0.10 | $404,712 | $38,387 | $2,817 | $445,916 | $46,973,648 |
| 31 | 0.09 | $374,733 | $38,852 | $2,712 | $416,297 | $47,389,945 |
| 32 | 0.09 | $346,975 | $39,321 | $2,612 | $388,908 | $47,778,854 |
| 33 | 0.08 | $321,273 | $39,797 | $2,515 | $363,585 | $48,142,439 |
| 34 | 0.07 | $297,475 | $40,278 | $2,422 | $340,176 | $48,482,615 |
| 35 | 0.07 | $275,440 | $40,766 | $2,332 | $318,538 | $48,801,153 |
| 36 | 0.06 | $255,037 | $41,259 | $2,246 | $298,542 | $49,099,694 |
| 37 | 0.06 | $236,145 | $41,758 | $2,163 | $280,066 | $49,379,760 |
| 38 | 0.05 | $218,653 | $42,263 | $2,083 | $262,999 | $49,642,759 |
| 39 | 0.05 | $202,457 | $42,774 | $2,006 | $247,236 | $49,889,995 |
| 40 | 0.05 | $187,460 | $43,291 | $1,931 | $232,682 | $50,122,677 |

## Underground 345kV HPFF

| First Costs | | Losses | |
|---|---|---|---|
| Ducts & Vaults | $5,905,100 | Cable | 2500 kcmil |
| Cable & Hardware | $5,073,396 | Resistance | 0.0317 ohms/mi |
| Site Work | $2,994,135 | Peak Line Current | 1000 amps |
| Construction | $332,682 | Load Growth | 2.03% |
| Engineering | $499,023 | Loss Factor | 0.38 |
| Sales Tax | $520,314 | Energy Cost | 100 mils/kWh |
| Admin/PM | $1,309,436 | Energy Cost Escalation | 5.0% |

| Year | PV Factor | First Costs | Loss | O&M | PV Cost | Cum PV |
|---|---|---|---|---|---|---|
| 1 | 0.93 | $2,171,672 | $32,052 | $8,415 | $2,212,140 | $2,212,140 |
| 2 | 0.86 | $2,010,808 | $32,440 | $8,104 | $2,051,351 | $4,263,490 |
| 3 | 0.79 | $1,861,859 | $32,832 | $7,804 | $1,902,494 | $6,165,985 |
| 4 | 0.74 | $1,723,944 | $33,229 | $7,514 | $1,764,687 | $7,930,672 |
| 5 | 0.68 | $1,596,244 | $33,631 | $7,236 | $1,637,111 | $9,567,783 |
| 6 | 0.63 | $1,478,004 | $34,038 | $6,968 | $1,519,010 | $11,086,792 |
| 7 | 0.58 | $1,368,522 | $34,449 | $6,710 | $1,409,681 | $12,496,474 |
| 8 | 0.54 | $1,267,150 | $34,866 | $6,462 | $1,308,478 | $13,804,951 |
| 9 | 0.50 | $1,173,287 | $35,288 | $6,222 | $1,214,797 | $15,019,748 |
| 10 | 0.46 | $1,086,377 | $35,715 | $5,992 | $1,128,083 | $16,147,831 |
| 11 | 0.43 | $1,005,904 | $36,147 | $5,770 | $1,047,821 | $17,195,652 |
| 12 | 0.40 | $931,393 | $36,584 | $5,556 | $973,533 | $18,169,185 |
| 13 | 0.37 | $862,401 | $37,026 | $5,350 | $904,778 | $19,073,963 |
| 14 | 0.34 | $798,519 | $37,474 | $5,152 | $841,146 | $19,915,109 |
| 15 | 0.32 | $739,370 | $37,927 | $4,961 | $782,259 | $20,697,367 |
| 16 | 0.29 | $684,602 | $38,386 | $4,778 | $727,765 | $21,425,132 |
| 17 | 0.27 | $633,890 | $38,850 | $4,601 | $677,341 | $22,102,474 |
| 18 | 0.25 | $586,936 | $39,320 | $4,430 | $630,686 | $22,733,160 |
| 19 | 0.23 | $543,459 | $39,796 | $4,266 | $587,521 | $23,320,681 |
| 20 | 0.21 | $503,203 | $40,277 | $4,108 | $547,588 | $23,868,269 |
| 21 | 0.20 | $465,928 | $40,764 | $3,956 | $510,649 | $24,378,918 |
| 22 | 0.18 | $431,415 | $41,257 | $3,810 | $476,482 | $24,855,400 |
| 23 | 0.17 | $399,459 | $41,756 | $3,668 | $444,883 | $25,300,283 |
| 24 | 0.16 | $369,869 | $42,261 | $3,533 | $415,663 | $25,715,946 |
| 25 | 0.15 | $342,471 | $42,773 | $3,402 | $388,646 | $26,104,591 |
| 26 | 0.14 | $317,103 | $43,290 | $3,276 | $363,669 | $26,468,260 |
| 27 | 0.13 | $293,614 | $43,813 | $3,154 | $340,582 | $26,808,842 |
| 28 | 0.12 | $271,865 | $44,343 | $3,038 | $319,246 | $27,128,087 |
| 29 | 0.11 | $251,727 | $44,880 | $2,925 | $299,531 | $27,427,619 |
| 30 | 0.10 | $233,080 | $45,423 | $2,817 | $281,319 | $27,708,938 |
| 31 | 0.09 | $215,815 | $45,972 | $2,712 | $264,499 | $27,973,438 |
| 32 | 0.09 | $199,829 | $46,528 | $2,612 | $248,969 | $28,222,406 |
| 33 | 0.08 | $185,027 | $47,091 | $2,515 | $234,633 | $28,457,039 |
| 34 | 0.07 | $171,321 | $47,660 | $2,422 | $221,403 | $28,678,442 |
| 35 | 0.07 | $158,630 | $48,237 | $2,332 | $209,200 | $28,887,642 |
| 36 | 0.06 | $146,880 | $48,820 | $2,246 | $197,946 | $29,085,588 |
| 37 | 0.06 | $136,000 | $49,411 | $2,163 | $187,574 | $29,273,162 |
| 38 | 0.05 | $125,926 | $50,008 | $2,083 | $178,017 | $29,451,178 |
| 39 | 0.05 | $116,598 | $50,613 | $2,006 | $169,217 | $29,620,395 |
| 40 | 0.05 | $107,961 | $51,225 | $1,931 | $161,118 | $29,781,513 |

## Underground 345kV 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 | 1000 amps |
| Construction | $439,414 | Load Growth | 2.03% |
| Engineering | $659,121 | Loss Factor | 0.38 |
| Sales Tax | $697,350 | Energy Cost | 100 mils/kWh |
| Admin/PM | $1,939,134 | Energy Cost Escalation | 5.0% |

| Year | PV Factor | First Costs | Loss | O&M | PV Cost | Cum PV |
|---|---|---|---|---|---|---|
| 1 | 0.93 | $2,868,397 | $27,088 | $8,415 | $2,903,900 | $2,903,900 |
| 2 | 0.86 | $2,655,923 | $27,415 | $8,104 | $2,691,442 | $5,595,342 |
| 3 | 0.79 | $2,459,188 | $27,747 | $7,804 | $2,494,738 | $8,090,080 |
| 4 | 0.74 | $2,277,026 | $28,082 | $7,514 | $2,312,623 | $10,402,703 |
| 5 | 0.68 | $2,108,357 | $28,422 | $7,236 | $2,144,016 | $12,546,718 |
| 6 | 0.63 | $1,952,183 | $28,766 | $6,968 | $1,987,917 | $14,534,635 |
| 7 | 0.58 | $1,807,577 | $29,114 | $6,710 | $1,843,400 | $16,378,035 |
| 8 | 0.54 | $1,673,682 | $29,466 | $6,462 | $1,709,609 | $18,087,645 |
| 9 | 0.50 | $1,549,706 | $29,822 | $6,222 | $1,585,750 | $19,673,395 |
| 10 | 0.46 | $1,434,913 | $30,183 | $5,992 | $1,471,087 | $21,144,482 |
| 11 | 0.43 | $1,328,623 | $30,548 | $5,770 | $1,364,941 | $22,509,423 |
| 12 | 0.40 | $1,230,206 | $30,917 | $5,556 | $1,266,680 | $23,776,103 |
| 13 | 0.37 | $1,139,080 | $31,291 | $5,350 | $1,175,722 | $24,951,824 |
| 14 | 0.34 | $1,054,704 | $31,670 | $5,152 | $1,091,526 | $26,043,350 |
| 15 | 0.32 | $976,577 | $32,053 | $4,961 | $1,013,592 | $27,056,942 |
| 16 | 0.29 | $904,238 | $32,441 | $4,778 | $941,457 | $27,998,398 |
| 17 | 0.27 | $837,258 | $32,833 | $4,601 | $874,691 | $28,873,090 |
| 18 | 0.25 | $775,239 | $33,230 | $4,430 | $812,899 | $29,685,989 |
| 19 | 0.23 | $717,814 | $33,632 | $4,266 | $755,712 | $30,441,700 |
| 20 | 0.21 | $664,642 | $34,039 | $4,108 | $702,789 | $31,144,489 |
| 21 | 0.20 | $615,409 | $34,450 | $3,956 | $653,816 | $31,798,305 |
| 22 | 0.18 | $569,824 | $34,867 | $3,810 | $608,500 | $32,406,806 |
| 23 | 0.17 | $527,614 | $35,289 | $3,668 | $566,572 | $32,973,377 |
| 24 | 0.16 | $488,532 | $35,716 | $3,533 | $527,780 | $33,501,158 |
| 25 | 0.15 | $452,344 | $36,148 | $3,402 | $491,894 | $33,993,051 |
| 26 | 0.14 | $418,837 | $36,585 | $3,276 | $458,698 | $34,451,749 |
| 27 | 0.13 | $387,812 | $37,027 | $3,154 | $427,994 | $34,879,743 |
| 28 | 0.12 | $359,085 | $37,475 | $3,038 | $399,598 | $35,279,342 |
| 29 | 0.11 | $332,487 | $37,929 | $2,925 | $373,340 | $35,652,682 |
| 30 | 0.10 | $307,858 | $38,387 | $2,817 | $349,062 | $36,001,744 |
| 31 | 0.09 | $285,054 | $38,852 | $2,712 | $326,618 | $36,328,361 |
| 32 | 0.09 | $263,939 | $39,321 | $2,612 | $305,872 | $36,634,233 |
| 33 | 0.08 | $244,388 | $39,797 | $2,515 | $286,700 | $36,920,933 |
| 34 | 0.07 | $226,285 | $40,278 | $2,422 | $268,985 | $37,189,918 |
| 35 | 0.07 | $209,523 | $40,766 | $2,332 | $252,621 | $37,442,539 |
| 36 | 0.06 | $194,003 | $41,259 | $2,246 | $237,507 | $37,680,047 |
| 37 | 0.06 | $179,632 | $41,758 | $2,163 | $223,553 | $37,903,599 |
| 38 | 0.05 | $166,326 | $42,263 | $2,083 | $210,671 | $38,114,271 |
| 39 | 0.05 | $154,006 | $42,774 | $2,006 | $198,785 | $38,313,056 |
| 40 | 0.05 | $142,598 | $43,291 | $1,931 | $187,820 | $38,500,876 |

## Underground 345kV HPFF Double-Circuit

| First Costs | | Losses | |
|---|---|---|---|
| Ducts & Vaults | $9,084,770 | Cable | 2500 kcmil |
| Cable & Hardware | $7,805,225 | Resistance | 0.0317 ohms/mi |
| Site Work | $4,606,362 | Peak Line Current | 1000 amps |
| Construction | $511,818 | Load Growth | 2.03% |
| Engineering | $639,773 | Loss Factor | 0.38 |
| Sales Tax | $800,483 | Energy Cost | 100 mils/kWh |
| Admin/PM | $2,142,470 | Energy Cost Escalation | 5.0% |

| Year | PV Factor | First Costs | Loss | O&M | PV Cost | Cum PV |
|---|---|---|---|---|---|---|
| 1 | 0.93 | $3,341,034 | $32,052 | $8,415 | $3,381,501 | $3,381,501 |
| 2 | 0.86 | $3,093,550 | $32,440 | $8,104 | $3,134,093 | $6,515,595 |
| 3 | 0.79 | $2,864,398 | $32,832 | $7,804 | $2,905,034 | $9,420,629 |
| 4 | 0.74 | $2,652,221 | $33,229 | $7,514 | $2,692,964 | $12,113,593 |
| 5 | 0.68 | $2,455,760 | $33,631 | $7,236 | $2,496,627 | $14,610,220 |
| 6 | 0.63 | $2,273,852 | $34,038 | $6,968 | $2,314,858 | $16,925,078 |
| 7 | 0.58 | $2,105,418 | $34,449 | $6,710 | $2,146,578 | $19,071,655 |
| 8 | 0.54 | $1,949,461 | $34,866 | $6,462 | $1,990,789 | $21,062,444 |
| 9 | 0.50 | $1,805,057 | $35,288 | $6,222 | $1,846,567 | $22,909,011 |
| 10 | 0.46 | $1,671,349 | $35,715 | $5,992 | $1,713,055 | $24,622,067 |
| 11 | 0.43 | $1,547,545 | $36,147 | $5,770 | $1,589,462 | $26,211,528 |
| 12 | 0.40 | $1,432,912 | $36,584 | $5,556 | $1,475,052 | $27,686,580 |
| 13 | 0.37 | $1,326,771 | $37,026 | $5,350 | $1,369,147 | $29,055,728 |
| 14 | 0.34 | $1,228,491 | $37,474 | $5,152 | $1,271,118 | $30,326,845 |
| 15 | 0.32 | $1,137,492 | $37,927 | $4,961 | $1,180,381 | $31,507,226 |
| 16 | 0.29 | $1,053,233 | $38,386 | $4,778 | $1,096,397 | $32,603,623 |
| 17 | 0.27 | $975,216 | $38,850 | $4,601 | $1,018,667 | $33,622,290 |
| 18 | 0.25 | $902,978 | $39,320 | $4,430 | $946,728 | $34,569,018 |
| 19 | 0.23 | $836,091 | $39,796 | $4,266 | $880,153 | $35,449,171 |
| 20 | 0.21 | $774,158 | $40,277 | $4,108 | $818,543 | $36,267,714 |
| 21 | 0.20 | $716,813 | $40,764 | $3,956 | $761,533 | $37,029,248 |
| 22 | 0.18 | $663,716 | $41,257 | $3,810 | $708,783 | $37,738,030 |
| 23 | 0.17 | $614,552 | $41,756 | $3,668 | $659,976 | $38,398,006 |
| 24 | 0.16 | $569,029 | $42,261 | $3,533 | $614,823 | $39,012,830 |
| 25 | 0.15 | $526,879 | $42,773 | $3,402 | $573,053 | $39,585,883 |
| 26 | 0.14 | $487,851 | $43,290 | $3,276 | $534,416 | $40,120,299 |
| 27 | 0.13 | $451,714 | $43,813 | $3,154 | $498,682 | $40,618,981 |
| 28 | 0.12 | $418,253 | $44,343 | $3,038 | $465,634 | $41,084,615 |
| 29 | 0.11 | $387,272 | $44,880 | $2,925 | $435,077 | $41,519,692 |
| 30 | 0.10 | $358,585 | $45,423 | $2,817 | $406,824 | $41,926,516 |
| 31 | 0.09 | $332,023 | $45,972 | $2,712 | $380,707 | $42,307,223 |
| 32 | 0.09 | $307,429 | $46,528 | $2,612 | $356,569 | $42,663,792 |
| 33 | 0.08 | $284,656 | $47,091 | $2,515 | $334,262 | $42,998,054 |
| 34 | 0.07 | $263,571 | $47,660 | $2,422 | $313,653 | $43,311,707 |
| 35 | 0.07 | $244,047 | $48,237 | $2,332 | $294,616 | $43,606,323 |
| 36 | 0.06 | $225,969 | $48,820 | $2,246 | $277,035 | $43,883,359 |
| 37 | 0.06 | $209,231 | $49,411 | $2,163 | $260,804 | $44,144,163 |
| 38 | 0.05 | $193,732 | $50,008 | $2,083 | $245,823 | $44,389,986 |
| 39 | 0.05 | $179,382 | $50,613 | $2,006 | $232,000 | $44,621,987 |
| 40 | 0.05 | $166,094 | $51,225 | $1,931 | $219,251 | $44,841,237 |

## Underground 345kV XLPE Double-Circuit

| First Costs | | Losses | |
|---|---|---|---|
| Ducts & Vaults | $10,816,640 | Cable | 3000 kcmil |
| | | | 0.0268 |
| Cable & Hardware | $11,830,700 | Resistance | ohms/mi |
| Site Work | $5,408,320 | Peak Line Current | 1000 amps |
| Construction | $676,040 | Load Growth | 2.03% |
| Engineering | $1,690,100 | Loss Factor | 0.38 |
| Sales Tax | $1,072,875 | Energy Cost | 100 mils/kWh |
| Admin/PM | $2,307,325 | Energy Cost Escalation | 5.0% |

| Year | PV Factor | First Costs | Loss | O&M | PV Cost | Cum PV |
|---|---|---|---|---|---|---|
| 1 | 0.93 | $4,413,039 | $27,088 | $4,594 | $4,444,721 | $4,444,721 |
| 2 | 0.86 | $4,086,147 | $27,415 | $4,424 | $4,117,986 | $8,562,707 |
| 3 | 0.79 | $3,783,470 | $27,747 | $4,260 | $3,815,477 | $12,378,183 |
| 4 | 0.74 | $3,503,213 | $28,082 | $4,102 | $3,535,397 | $15,913,581 |
| 5 | 0.68 | $3,243,715 | $28,422 | $3,951 | $3,276,088 | $19,189,669 |
| 6 | 0.63 | $3,003,440 | $28,766 | $3,804 | $3,036,010 | $22,225,679 |
| 7 | 0.58 | $2,780,963 | $29,114 | $3,663 | $2,813,740 | $25,039,419 |
| 8 | 0.54 | $2,574,966 | $29,466 | $3,528 | $2,607,959 | $27,647,378 |
| 9 | 0.50 | $2,384,228 | $29,822 | $3,397 | $2,417,447 | $30,064,825 |
| 10 | 0.46 | $2,207,618 | $30,183 | $3,271 | $2,241,072 | $32,305,897 |
| 11 | 0.43 | $2,044,091 | $30,548 | $3,150 | $2,077,789 | $34,383,686 |
| 12 | 0.40 | $1,892,677 | $30,917 | $3,033 | $1,926,628 | $36,310,313 |
| 13 | 0.37 | $1,752,478 | $31,291 | $2,921 | $1,786,691 | $38,097,004 |
| 14 | 0.34 | $1,622,665 | $31,670 | $2,813 | $1,657,148 | $39,754,152 |
| 15 | 0.32 | $1,502,468 | $32,053 | $2,709 | $1,537,229 | $41,291,381 |
| 16 | 0.29 | $1,391,174 | $32,441 | $2,608 | $1,426,223 | $42,717,604 |
| 17 | 0.27 | $1,288,124 | $32,833 | $2,512 | $1,323,469 | $44,041,073 |
| 18 | 0.25 | $1,192,707 | $33,230 | $2,419 | $1,228,356 | $45,269,429 |
| 19 | 0.23 | $1,104,359 | $33,632 | $2,329 | $1,140,320 | $46,409,749 |
| 20 | 0.21 | $1,022,554 | $34,039 | $2,243 | $1,058,836 | $47,468,585 |
| 21 | 0.20 | $946,810 | $34,450 | $2,160 | $983,420 | $48,452,004 |
| 22 | 0.18 | $876,676 | $34,867 | $2,080 | $913,622 | $49,365,627 |
| 23 | 0.17 | $811,737 | $35,289 | $2,003 | $849,028 | $50,214,655 |
| 24 | 0.16 | $751,608 | $35,716 | $1,929 | $789,252 | $51,003,907 |
| 25 | 0.15 | $695,933 | $36,148 | $1,857 | $733,938 | $51,737,846 |
| 26 | 0.14 | $644,383 | $36,585 | $1,788 | $682,756 | $52,420,601 |
| 27 | 0.13 | $596,651 | $37,027 | $1,722 | $635,400 | $53,056,002 |
| 28 | 0.12 | $552,454 | $37,475 | $1,658 | $591,588 | $53,647,589 |
| 29 | 0.11 | $511,532 | $37,929 | $1,597 | $551,057 | $54,198,647 |
| 30 | 0.10 | $473,641 | $38,387 | $1,538 | $513,566 | $54,712,212 |
| 31 | 0.09 | $438,556 | $38,852 | $1,481 | $478,888 | $55,191,101 |
| 32 | 0.09 | $406,070 | $39,321 | $1,426 | $446,818 | $55,637,919 |
| 33 | 0.08 | $375,991 | $39,797 | $1,373 | $417,161 | $56,055,080 |
| 34 | 0.07 | $348,140 | $40,278 | $1,322 | $389,741 | $56,444,820 |
| 35 | 0.07 | $322,352 | $40,766 | $1,273 | $364,391 | $56,809,211 |
| 36 | 0.06 | $298,474 | $41,259 | $1,226 | $340,959 | $57,150,170 |
| 37 | 0.06 | $276,365 | $41,758 | $1,181 | $319,303 | $57,469,473 |
| 38 | 0.05 | $255,893 | $42,263 | $1,137 | $299,293 | $57,768,766 |
| 39 | 0.05 | $236,938 | $42,774 | $1,095 | $280,807 | $58,049,573 |
| 40 | 0.05 | $219,387 | $43,291 | $1,054 | $263,733 | $58,313,306 |