State of Connecticut
Connecticut Siting Council

Update of Life-Cycle Cost Studies for Overhead and Underground Electric Transmission Lines - 1996

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ACRES

Table of Contents

1 INTRODUCTION

In the mid 1990's, the Connecticut Siting Council commissioned a study to investigate the comparative life-cycle costs of overhead and underground transmission lines in accordance with the Connecticut General Statutes Section 16-50r. This study, titled "Life-Cycle Cost Studies for Overhead and Underground Electric Transmission Lines", was issued in July 1996.

This present study is to report on developments within the industry since 1996 and to comment on the current validity of the conclusions and data contained in the 1996 study report.

2 EXECUTIVE SUMMARY

There have been and are ongoing developments within the industry since the preparation of the original study during the period 1995/96. All components, of both overhead and underground transmission systems have experienced incremental improvements in performance through the normal ongoing progress in technology and the industry's greater emphasis on quality control both during manufacturing and installation. Much research and development into new technologies is occurring, which will lead to future enhancements in the performance of transmission lines. Transmission lines are built to provide safe reliable performance over a life of 35 - 40 years. Existing technology has been proven over a number of years whereas new developments often need time to demonstrate their safety/reliability before being accepted.

Generally, the findings of the 1996 study are still valid today in 2000. However, there have been some developments which may impact on construction and operation of transmission lines over the next few years. These are

- **Line Ratings** - New techniques have been developed to increase power flows above "book" ratings over existing transmission lines without expenditure on assets.
- **NESC** - A new revision of the National Electricity Safety Code is due to be issued in 2002. Revisions to existing loading and strength criteria, which are under consideration, may result in marginal increases in first costs.
- **Wood Pole Preservative** - There is a possibility that the most commonly used preservative, penta, may be banned by the EPA. If this occurs, then more costly steel poles may have to be used as replacement for Western Red Cedar poles pending the development of a substitute acceptable preservative.
- **Solid Dielectric Cables (XLPE)** - The reliability of these cable systems has improved considerably over the last few years. Given the cost benefits of XLPE, serious consideration should be given to their utilization over gas or fluid filled systems.
- **Line Upgrading** - The terms of reference for the 1996 study were to report only on completely new facilities. However, upgrading existing facilities to increase line or corridor capacity is sometimes a more economical alternative to the complete replacement of existing facilities with new.

3 OVERHEAD LINES

3.1 Line Ratings

The 1996 report considered two base cases for 115 kV lines – Scenario A (795 kcmil ACSR conductor) and Scenario B (1272 kcmil ACSR conductor). Recent experience in the United States has confirmed that utility restructuring and open access generation have resulted in an upward trend for current flow on some transmission lines resulting in a need for an increase in operating temperatures of line conductors above the traditional everyday levels.

Table 1.2, page A-3, of the 1996 report specifies the Summer and Winter load level scenarios and ratings. The normal ratings of the 795 and 1272 kcmil ACSR conductors are 1000 and 1250 Amps respectively as compared to the average load levels of 350 and 500 Amps respectively assumed for the life-cycle analysis.

For 795 kcmil conductor in a sheltered right-of-way, the Summer load of 350 Amps results in a conductor temperature of approximately 110°F. Similarly, for the 1272 kcmil conductor the Summer load of 500 Amps results in a conductor temperature of 115°F. The Summer normal ratings of 1000 Amps (for 795 kcmil) and 1250 Amps (for 1272 kcmil) result in conductor temperatures of approximately 195°F and 190°F respectively. For both conductors, the temperatures resulting from the maximum normal continuous summer ratings of 1000 and 1250 Amps, respectively, are on the limit of annealing.

Wind speed and direction have the most profound effect on conductor temperatures. These are the two most uncertain and variable factors along transmission lines. Numerous techniques and technologies have been developed, worldwide, to maximize the power transfer capabilities of existing transmission lines. Some of the more common techniques are listed below (and described in detail in recent reference publications):

- Development of thermal rating standards
- Probabilistic methods of line ratings
- Real time monitoring systems
- Operation of standard ACSR conductors at elevated temps.

Open transmission access and economic uncertainties are the major reasons causing many North American utilities to operate their existing lines at higher loads than the original design values. Due to this, IEEE has been actively engaged in studying the effects of higher operating temperatures on the safety and reliability of existing transmission lines. IEEE's Working Group on Thermal Aspects of Conductors and Accessories' approach encompasses the following elements:

- Identification of sources and magnitude of errors in as-built conductor sags in order to better define recommended safety buffers for clearances.
- Accurate determination of high temperature sags
- Probabilistic aspects of line rating and of the buffer component of clearances.

CIGRE SC22/WG12 paper describes methods to determine thermal ratings of lines in real time and application, thereof, in optimizing power flows. These methods are based on direct measurements (temperatures, sag/tensions), indirect measurements (from weather stations) or combination of both.

The use of weather predictions for transmissions line thermal ratings has been practiced by some utilities for a considerable period of time e.g., Entergy Corp., Florida Power Corp., and PG&E in the USA; National Grid, U.K.; ENEL, Italy; Ontario Hydro, Canada.

The magnitude of possible enhancements, above book ratings, depend on:

- The conservatism of the assumptions made in determination of book ratings
- The nature and variability of terrain traversed by the line route
- The meteorological environment associated with the route
- The method used in making the predictions
- The lead-time required for the prediction.

Enhancements of 10% or more above book ratings are generally readily achievable, although not necessarily on a daily basis. The National Grid, U.K. is implementing predictive thermal ratings for their overhead lines that is a combination of the weather prediction method with the probabilistic approach. On the four circuits to which this approach has been applied for operational use, enhanced ratings have been available on 65% to 75% of days. Enhancement on such days have ranged from 3% to 20% with averages of between 8% and 10%.

3.2 New Conductors

Conductors made of heat resistant aluminum strands, steel reinforced, for increasing the capacity of new and existing transmission lines have recently been developed and used in Japan. Two types of these conductors are available – gap-type construction known as GTACSR and invar-based conductors known as ZTACSR or XTACSR. The corresponding maximum operating temperatures are 355°F and 460°F.

It is claimed that the heat resistant aluminum alloy conductor steel reinforced, TACSR, can carry 1.6 times the ampacity and the super heat resistant aluminum alloy conductor invar reinforced (ZTACSR) 2.0 times the ampacity of the conventional ACSR conductors. These conductors are not yet commercially available outside Japan as they have yet to be approved by international or United States standards committees.

These new conductors are presently very expensive and may be economically justified for very heavy loading and when the line requires many heavy dead-end structures e.g. congestion conditions typical for densely populated countries such as Japan. In the latter case, the extra cost of these conductors is overwhelmed by the high cost of their supporting structures.

3.3 Reliability

In the wake of the January 1998 "ice storm of the Century" that hit Southern Quebec and Eastern Ontario, the issue of transmission line reliability is being given a close look by the industry. Typically, the mechanical and structural design of overhead transmission lines is based on safety, reliability, and security requirements.

Safety requirements specify construction and maintenance loads for which line components (mostly structure members) have to be designed to ensure that construction and maintenance operations do not pose additional safety hazards to personnel.

Reliability and security requirements specify the stresses that conductors and structures are likely to encounter over their service life. Depending on the importance of a line, it can be designed for higher reliability by increasing the "return period" of mechanical loading due to weather events.

The return period of a weather load (or a weather event) is a measure of the likelihood of a weather event of a given magnitude taking place within a certain time period. For example, a weather-related load that has a 2% chance of being exceeded in any given year is called a 50-year return-period load [probability = 100/(return period)]. Similarly, a 20-year return load has a 5% probability of being exceeded on any given year.

The January 1998 ice storm was unusually severe, with a very low probability of re-occurrence (once every 150 years or so). Following this ice storm, in-depth review of all transmission line design standards, line sustainment practices, ice accretion models, and mitigation measures has been performed by the affected utilities, and appropriate recommendations were made.

Comparing Canadian Standards Association (CSA) and NESC standards related to ice load, it is noted that the NESC radial ice thickness of 0.5" and 0.25" for heavy and medium loading zones respectively, are much lower than the radial ice thickness specified by Hydro Quebec and Ontario Hydro. For example, Ontario Hydro's "ice alone" radial ice thickness is 51 mm (2") and 25 mm (1") for 50 and 20-year return periods respectively.

One of the major impacts of the January 1998 ice storm is the increased R&D work in the area of methods to combat ice on line conductors. Ice monitoring systems and early warning systems on ice accumulation on conductors are again on the agenda. Ice/sleet melting technologies used by some of North Eastern utilities of USA 40-60 years ago are being revisited, and new ice melting methods are being tried. Proven ice melting technologies that were successfully applied on transmission lines in the Eastern European countries for the last 50 years are being studied. This topic is again on the agenda of CIGRE SC22/WG12.

In Canada, an organization called CIGELE (The Industrial Chair on Atmospheric Icing of Power Network Equipment) has been formed. It includes 5 Canadian and 5 foreign Universities. The partners of CIGELE are NSERC of Canada; Hydro Quebec; ALCAN Cable; STATNET, Norway; Energy Atomic, Canada; and Phillips-Fitel. The objective of this organization is fundamental research aiming at developing and diffusing new knowledge in atmospheric icing.

The present edition (1997) of the National Electric Safety Code (NESC) contains no changes having a significant effect on the designs considered in the 1996 report. The next revision of the NESC is due to be published in 2002 and the following significant changes, specifically relating to ice and wind loading, are being considered:

- Complete revision of the Loading and Strength Sections 25-27, conceptual departure from the traditional deterministic method to the probabilistic-based Load Resistance Factored Design (LRFD).
- Elimination of NESC loading zones (light, medium and heavy) and replacement with new ice and wind maps based on geographical principles.
- American Society of Civil Engineers (ASCE) guidelines for loading and strength (ASCE Manual 74).

In particular the changes being considered to be included in NESC-2002 will affect the following:

- Transmission
- Distribution
- Steel and wood structures
- Spans
- Wind loading
- Ice loading
- Construction and maintenance loading
- Load factors
- Loaded wire tension limits
- Extreme wind loading
- Combined (ice plus wind) loading.

It is anticipated that any changes in the new NESC will have no significant effect on first cost or operational costs of transmission lines in Connecticut due to the fact that the two utilities already exceed the minimum requirements of the present version of the NESC.

3.4 Wood Pole Preservatives

Pressure treatments of wood poles with preservatives prolong wood pole life.

The latest document distributed by IEEE-SA in June 2000 for balloting recommends the use of the following preservatives: creosote, pentachlorophenol (penta), CCA or ACZA, copper Naphthenate (Table 4 - AWPA standards to be used).

The National Coalition Against the Misuse of Pesticides (NCAMP), a Washington, D.C. based group founded in 1981 that monitors the use of pesticides and other toxic chemicals claim that penta and creosote (a derivative of coal and tar) are environmentally dangerous pesticides. EPA has placed these substances under review.

Questions about the environmental safety of traditional wood preservatives motivated EPRI research on wood decay processes and alternative chemicals for treating utility poles. The deliverable of this project were two environmentally friendly new wood preservatives, the first in 50 years, namely: ammoniacal copper carboxylate (ACC), and chromated copper arsenate (CCA). Both are water-borne preservatives as compared to the oil-borne penta. Water-borne preservative treated woods exhibit better immunity to fires than oil-borne preservative treated woods. From the point of view of safety, the performance of water-borne and oil-borne preservative-treated poles is comparable in that no hazard to linemen contacting the poles near ground level exists. ACC contains no toxic arsenate and makes wood pole easier to climb.

Many utilities have discontinued the use of creosote for several years and the water-borne preservatives do not penetrate Western Red Cedar, the most common wood pole used in the industry. Therefore, if EPA phases out the use of penta, steel pole replacement may be considered as the alternative for new construction and maintenance replacements. Laminated Southern Yellow Pine wood poles could also be considered, however, these are susceptible to separation of laminations due to field drilling of holes.

For the assumed life expectancy of 35 years, any cost beyond 35 years of life offers little contribution towards the life-cycle cost because 90% of present value occurs in first 22 years. Life expectancy of steel poles equal to 60 years as may be suggested by the steel pole manufacturers should be taken with caution. For most of steel pole designs used as wood pole replacement (single or H-frame), no loss of wall thickness due to corrosion is acceptable. Effective corrosion protection is the major factor affecting the longevity of steel poles for wood pole replacement. Thus affecting significantly the life-cycle cost of such replacement projects.

One of the corner stones of wood pole management programs is the development of the end-of-life criteria. End-of-life criteria of line components are reliability centered maintenance programs and these provide essential information for decision making for capital and O&M projects.

3.5 Electric and Magnetic Fields

The methods for the calculation of electric and magnetic fields are based on the basic principles of electricity and have not changed. Computer hardware and software platforms have become more sophisticated allowing a more comprehensive (three-dimensional, visual, etc.) modeling.

Recent research has tended to concentrate more on electric field effects (electrostatic and electromagnetic induction) rather than magnetic fields. Extensive research, worldwide, has failed to produce conclusive evidence that electric and magnetic fields are a health hazard.

3.6 Polymer Insulators

Polymer insulators, which were included in the 1996 study, have become more acceptable to utilities due to longer experience record and proven advantages over the traditional porcelain or glass insulators. Recent developments have improved performance characteristics and longer trouble free life spans, resulting in a reduction in maintenance costs associated with the insulators. The latest development is the new generation of hollow core polymer insulators with an improved strength to weight ratio.

The advantages of the composite insulators are:

- low weight
- high strength and flexibility
- high impact strength and greater resistance to vandalism
- pollution performance
- environmental aspect.

Recent enhancements include:

- single piece molded weathershed
- swaged end fittings
- elastomer covering (EPDM or Silicone)
- elastomer bonded to rod and fittings
- improved testing methods.

The establishment of open electricity market is causing transmission utilities to refocus their attention. Instead of driving their older assets harder they are now more concerned with improving asset value and reducing O&M costs. Thus leads to condition-based maintenance over routine maintenance and large-scale utilization of new technologies to support it.

Following several years of evaluation, polymer insulation is now the preferred form of insulation. It is now not only less expensive than ceramic but also has reduced ongoing maintenance philosophy. To combat the costly maintenance methods traditionally used for remote transmission lines helicopters are now seen as a cost-effective alternative, particularly when combined with improved condition monitoring equipment.

It is important to obtain information from HV lines regarding the service reliability of polymer insulators in respect of maintenance cycles. The ground-based tools for inspection of in-service insulators include the following:

- visual inspection devices
- standard image intensifiers
- corona optimized image intensifiers
- daytime corona camera
- infrared imaging devices
- acoustic emission sensing devices
- radio interference monitors.

3.7 Fiber Optic Communications

Fiber optic communications systems on overhead transmission lines were not considered in the 1996 study. These systems, in addition to meeting the utility's own communication needs, have the potential to generate revenue through leasing to third parties.

Overhead ground wires with built-in fiber optics (OPGW) are considered to be a proven technology after about 20 years of positive international experience.

The latest development is phase conductors with built-in fiber optics called Optical Fiber Phase Wires (OPPW). The core of OPPW consists of alumoweld wires and one of the seven steel strands is replaced with a special steel tube containing fiber optics. Corresponding fittings have been developed. OPPW is available in sizes from 50 mm^2 to 305 mm^2.

OPPW offers new opportunities for installation of fiber optic-based communication on transmission lines where ground wires are not installed, as well as utilization of fiber optic-based technologies for distributed temperature sensing, real time monitoring, dynamic thermal rating, etc.

Pirelli has recently developed an insulated medium-voltage aerial cable having a messenger with built-in fiber optic cable. This insulated aerial cable called ECOAR

ECOS system is more reliable than bare conductor lines, because it can withstand damage caused by ice and fallen trees without interruption. Furthermore, it is not necessary to maintain the exclusion zone as is required for a bare overhead line, which reduces maintenance costs. The messenger in the ECOAR ECOS system integrates mechanical, electrical and optical data transmission functions. It allows the use of 500-ft spans. The first application of the ECOAR ECOS system was in Italy, where it was installed under the supervision of ENEL and Pirelli. The line that connects two large sections of telecommunication networks, straddles high-voltage overhead lines that cross rural areas and woodlands. The pilot installation was an optimum test for the system because it covers many possible line variations: aerial and underground sections in rural, level and hilly woodland areas; adjustable clamps; and electrical and fiber optical joints.

3.8 Asset Management and Condition Assessment Technologies

The following is a list of recent technical advances and technologies that are allowing utilities to increase the flow of power across their transmission lines while still maintaining or even improving their reliability, namely:

- Dynamic Thermal Circuit Rating or Real Time Monitoring
- Flow Control Devices
- Dispersed generation or energy storage options located at critically overloaded lines and substations
- Use of low-sag conductors (ACSS/TW, heat-resistant aluminum alloy, other)
- Advanced Airborne Inspection Systems (AIS) using a combination of laser, radar, and IR or UV systems, to verify actual line conditions e.g. to locate bad insulators, failing conductor splices, substandard clearances, etc.
- Automated transmission line inspection system leading to reliability improvement while reducing O&M costs.
- On-line assessment of the present condition of ACSR
- Assessing the condition of structure foundations
- Ultrasonic inspection of anchor rods
- Non-destructive technologies to assess the condition of wood poles
- On-line assessment of condition of line insulators
- End-of-life criteria of line components as a base for reinvestment strategy
- Aerial videography maps
- Helicopter-mounted tree trimming.

These developments have given utilities the tools to optimize their maintenance budgets and to target their maintenance programs more effectively, often resulting in substantial increases in the life of transmission lines.

3.9 Line Upgrading

When there is no possibility of acquiring new right-of-ways for transmission lines, the need to increase power density of the existing right-of-ways becomes an important consideration. There are several ways to ensure safe and reliable increased power transfer capability, namely:

- Re-rating transmission lines for higher operating temperatures
- Rebuilding of the old lines using the state-of-the art techniques for design and construction of compact H.V. lines, multi-circuit and/or multi-voltage lines
- Real time monitoring technologies.

There is currently great interest in and awareness of the subject of the uprating of old lines and the subject is going to grow in importance in the future. The need for increased power transfer capability is being encountered by pressures to limit or, in some cases, to totally exclude the building of new transmission facilities on new corridors.

All of this puts the focus on existing lines where the questions arise as to the physical condition and future life expectancy of some of the older lines and the more challenging task of devising means to economically and safely increase the transfer capability of some of those existing lines; that is by line uprating.

The options for uprating existing lines are:

- Current (criteria, bundling, monitoring, reconductoring)
- Voltage (conductors, corona, insulation, clearances)
- Inductance (bundling, configuration).

The utility industry has been finding recently that the possibilities of line uprating include many concepts, from conversion from low-voltage to higher voltage circuit(s), the replacement of the existing conductor system, or operating lines at higher operating temperatures than originally designed for.

The first step in any work with an old line is to assess the present capacity of the existing facilities. This will usually be a verification of the original design capacity, which may or may not be significantly reduced by deterioration of some components. Such an exercise is begun by determining the condition of the existing line components by visual inspection, by sampling, by in-situ testing and by calculation and analysis.

This assessment of existing conditions must then be followed by a determination of the required strength of the system and this required strength is not necessarily the strength based on the original design assumptions. This strength or capacity is then compared with the estimated demands of the future life of the same system or the possibly increased demands of an uprated system.

Uprating of an existing line such as by reconductoring can only be attempted on a line that has demonstrated over a period of years that it has some reserve of strength to resist the weather-related loads that have occurred. If there is a significant record of failures due to weather-related loads, that record would be an indication that the line strength is marginal at best. There would be little justification for attempting an uprating without major changes of the existing structures and foundations. Thus the first premise is that operational experience is good enough to indicate that there is some, maybe poorly defined, extra margin of strength that might be exploited to permit successful operation with a larger conductor.

A larger conductor imposing greater loads on the existing structures will evidently reduce the reliability of the line. Extrapolation of synoptic wind data by Gumbel projections will demonstrate that a doubling of the return period of a wind event will typically result in a wind speed increase of 6 to 7%, for a pressure or load increase of about 15%. A similar 15% increase in loads is considered a valid value for a doubling of the return period of a precipitation ice storm. A 15% increase in conductor wind loads on a suspension structures and foundations of a new line would increase their costs by maybe 3% and result in increase in overall line costs of less than 1%.

However, when trying to uprate an existing line for large conductors and attempting to use existing structural components, the cost of a simple double of the return period of the load can be very large and the whole relationship of costs and benefits can change dramatically.

When renovating and specially when uprating an existing line, full advantage should be taken of beneficial terrain and cover conditions as they exist at each and every span or structure. Avoiding reinforcement of an existing structure and foundation saves much more than the cost of the study and analysis.

Line direction relative to the direction of critical winds (not always the same as the prevailing wind direction) can provide further justification for reducing the site specific conductor wind load criteria. This subject of the direction of destructive winds is one of the most significant for line designers and should be incorporated in studies of line upratings.

Reappraising the loading criteria for an uprated line, the line designer should not lose sight of the possibilities of both changing the conductor design or materials and of equal importance, making changes to the usage, or limits of use, that are applied to the conductor. For example, use of compact/TW ACSR with trapezoidal wires has been proven very economic where conductor replacement on old lines is considered. The application of the H/w concept of vibration control may lead to reduced steel content and lower weight but larger conductors.

All lines in USA are governed by NESC. This code imposes deterministic, voltage-specific limits on line clearances. Individual existing lines have widely different "templating" temperatures, some as low as 120°F or as high as 300°F.

Rating practices and assumptions vary from utility to utility. The most common practice is to calculate line ratings based on coincident high ambient temperature, full solar radiation, and an effective wind speed of 2 ft/s.

Another important traditional practice has been the use of clearance buffers in addition to the NESC clearances. These buffers are allowed for inaccuracies in design and construction of lines, as well as for uncertainties in conductor properties. These buffers may vary from 6 in. to 6 ft according to a CIGRE survey.

Historically, the industry practices and objectives were to predict conductor behavior for normal operating temperatures in the range of up to 160°F with sufficient accuracy. However, for higher operating temperatures that may take place as a result of uprating, those predictions are more complicated.

Line rating may be affected by the method of calculation. The ampacity rating calculated by IEEE and CIGRE methods may vary by almost 10% depending on the environmental conditions being considered. Although these two standards use the same heat balance concept, they use different approaches to calculate ampacity ratings.

Utilities search for inexpensive, incremental methods that will increase the thermal capacity of their H.V. lines. In this respect, several different incremental uprating methods can be combined to increase thermal ratings while reducing the risk of overloading. Among the incremental methods available for this purpose, the most widely used are:

- Assumption of less conservative weather conditions for conductor environment
- Use of a higher operating temperature
- Use of real-time, rather than fixed, weather conditions.

The upgrading of the operating voltage of an existing line is sometimes an effective method of increasing power flows. The potential for achieving this economically depends on several factors; the major ones being the existing line clearances (both internal and external) and the size of the existing conductor. If the existing conductor is large enough to operate at the higher voltage, it may be possible to overcome clearance problems by utilizing compact design philosophy. However, if the existing conductor has to be replaced with a larger size in order to limit corona losses, then the loading on the structures will increase. This usually results in the requirement for major reinforcement or even replacement of existing structures.

Increasing the operating voltage is usually only considered for one increment, i.e. from 69 kV to 115 kV or from 115 kV to 230 kV. Some of the existing 115 kV lines, in Connecticut, have already been upgraded from original 69 kV designs and the feasibility of further increasing the operating voltage of these lines is highly unlikely. In addition, increasing the operating voltage will require replacement of equipment (i.e. transformers, breakers, etc.) in the corresponding substation as the existing equipment will not be rated for the higher voltage.

The introduction of a new intermediate voltage level of 230 kV within the Connecticut system would constitute a major step requiring extensive detailed technical and financial studies of the implications. It is highly unlikely that such studies will demonstrate the feasibility of the 230 kV option.

4 UNDERGROUND LINES

4.1 Solid Dielectric Cables

Solid dielectric (XLPE) insulated cables were fully addressed in the 1996 study. The first costs and the life cycle costs were generally determined to be lower than the corresponding values for the gas and fluid filled alternatives.

Initially, many utilities were reluctant to utilize XLPE cables due to justifiable concerns about the quality control during the manufacturing process and the reliability of joints and terminations. Reliability of power supply must be a paramount consideration for utilities and therefore, this reluctance was fully justified.

Over the last few years, manufacturers have improved testing and quality controls with the result that the risks of cable failure have decreased significantly. In addition, more dependable field tests such as the HI-POT ac testing and partial discharge testing have increased confidence in the installation process, specially where joints and terminations are concerned.

These improvements have resulted in XLPE cables being accepted as proven technology for applications up to and including 230-kV. Recently, fairly large scale installations of 400 and 500-kV XLPE have been carried out. Hydro Quebec has carried out prequalification testing of 500 kV XLPE cables at its IREQ High Voltage Laboratory. 400 kV XLPE cables have been in service for a few years in Copenhagen (22 km), Berlin (7 km) and 40 km of 500 kV cables are to be commissioned in Japan later this year.

4.2 Directional Drilling

Technological improvements have led to horizontal directional drilling becoming a proven technology for installation of high voltage cables in locations with restrictions on constructability (under highways, rivers, etc.) or for environmentally sensitive areas. The construction costs of this method is trending lower.

The introduction of High Density Polyethylene (HDPE) pipe for directional drilling instead of steel pipe allows the installation of each phase in a separate non-metallic duct.

4.3 Superconductivity

Pirelli of Italy has announced, in the context of its research and development association with Electricite de France (EDF), the construction of the first high-temperature superconducting (HTS) prototype cable. The project includes the feasibility study, construction, experimentation and long-term testing of a prototype system. Pirelli developed and manufactured the prototype cable using HTS wire supplied by American Superconductor Corporation. The 66 ft prototype cable is of a “cold dielectric” coaxial design and can carry up to 2000 Amps with electrical losses of less than 1 W/m. It’s electrical insulation is designed to withstand an alternating voltage of 225 kV between phases. In a 3-phase transmission system this HTS cable would enable the transmittal of 1000 MVA.

Pirelli and Detroit Edison are carrying out a joint "HTS Cable Field Demonstration" project, supported by the U.S. Department of Energy Superconductivity Partnership Initiative II. The project involves the design, engineering, installation, testing and routine operation of 24 kV, 100 MVA 3-phase Warm Dielectric cable system to be retrofitted to replace existing conventional cables at Detroit Edison's Frisbie Station. Three HTS cables, 400 ft long, will replace nine existing conventional 24-kV cables which together carry a total power of 100 MVA; thus at 24 kV each cable will carry 2400 Amps rms.

Superconducting cables are presently in the development stage and still a few years away from commercial applications.

5 LIFE-CYCLE COSTS

First cost data, published by Handy-Whitman, indicates that first costs for total transmission plant increased 6.5% from mid 1995 to mid 1999. The change in cost of the various components ranged from a high of 11.0% for towers to an actual reduction of 3.0% for overhead conductors. The latter reduction reflects the volatility of the price of aluminum, a commodity, which is the major component of the price of overhead conductors. The Consumer Price Index (CPI) increased by 9.7% during this same period. Therefore, the overall increase in transmission plant has basically tracked the CPI if the volatile commodity component (price of aluminum) is ignored.

Figures supplied by Connecticut Light and Power Company indicate that their operation and maintenance (O&M) costs for overhead lines ranged from $1,474 to $1,862 per circuit-mile over the 3-year period 1996 - 1998 (inclusive). These numbers compare with the range $1,300 - $1,900 per circuit-mile indicated for year 10 in the 1996 study. CL&P have not been able to breakdown the O&M costs for underground line, but they estimate that the figures in the 1996 study remain realistic. Recent O&M data from United Illuminating (UI) have not been made available for this update study but there is no reason to believe that UI's experience is much different from that of CL&P.

In summary, the first costs of transmission lines have generally gone up in step with the CPI and the O&M costs are within the range considered in the 1996 study.