Northeast Utilities System

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December 12, 2005

Mr. S. Derek Phelps
Executive Director
Connecticut Siting Council
10 Franklin Square
New Britain, CT 06051

Re: Docket No. LIFE-CYCLE 2006 - LIFE-CYCLE 2006 - Connecticut Siting Council Investigation into the Life-Cycle Costs of Electric Transmission Lines

Dear Mr. Phelps:

This letter provides the response to requests for the information listed below.

With this filing, the Company has completed responding to all of the interrogatories requested during this proceeding.

Response to CSC-01 Interrogatories dated 11/23/2005
CSC - 001 , 002 , 003 , 004 , 005 , 006 , 007 , 008 , 009 , 010 , 011 , 012 , 013 , 014 , 015

Very truly yours,
Robert Carberry /tms
Robert Carberry
Manager
Transmission Siting and Permitting
NUSCO
As Agent for CL&P

RC/tms
cc: Service List

SERVICE LIST
Docket: LIFE-CYCLE 2006

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Connecticut Siting Council
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New Britain, CT 06051

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Atty. Michael C. Wertheimer
Office of the Attorney General
Ten Franklin Square
New Britain, CT 06051

Witness: CL&P Panel
Request from: Connecticut Siting Council

Question:
Provide all information documenting CL&P's costs for operation and maintenance of existing transmission lines. Where possible, please break these down by type of O&M expense, using cost categories that CL&P routinely uses. Please provide on a line-by-line basis, or by voltage category and type of line.

Response:
The attached table summarizes the Overhead Transmission O&M costs which CL&P reported to the Federal Energy Regulatory Commission for the years 2001 to 2004 (FERC Report Form No. 1, Accounts 56300 and 57100 for overhead transmission lines). From this data we have computed the average cost per circuit-mile in each year for CL&P's overhead transmission lines. This data excludes the costs of Operation Supervision and Engineering, and Maintenance Supervision and Engineering, FERC Accounts 56000 and 56800 respectively. An indeterminate share of the costs in these two FERC Accounts is associated with the operation and maintenance of transmission lines.

Note that breakdowns of O&M costs on a line-by-line basis or by line voltage are not available (N/A).

CL&P's comparable FERC Form No. 1 account data for Underground Transmission O&M costs also includes significant costs associated with 138-kV submarine cables between the Norwalk Harbor and Northport LI substations, a unique facility. Attempts to remove submarine cable charges from the data to yield meaningful O&M cost experience figures for CL&P's 43 miles of other land-based transmission cables (115-kV HPFF and XLPE) have proved difficult. As a result, CL&P has instead estimated that the annual costs of its underground transmission operation and maintenance program in recent years would have been approximately $150,000, or $3,488/mile. The basic work tasks of this program include routine inspections, dissolved gas analysis, vault cleaning (1/3rd per year), and some equipment repair work This figure again excludes the costs of Operation Supervision and Engineering, and Maintenance Supervision and Engineering, FERC Accounts 56000 and 56800 respectively. An indeterminate share of the costs in these two FERC Accounts is associated with the operation and maintenance of transmission lines.

Further to the matter of underground transmission, please note that CL&P has no actual operating and maintenance cost experience yet with underground 345-kV cable systems, either HPFF or XLPE. Therefore, the above estimate of CL&P's annual cost experience pertains to 115-kV cable systems only.

Also, please note that a significant and infrequently occurring maintenance event can distort maintenance costs in any given year, particularly for the underground transmission line asset class with its relatively small number of circuit miles. No such significant event for underground cables occurred during the years 2001-2004, but such an event did occur in 2005. The cost to repair a failed 115-kV HPFF underground cable in 2005 was over $1.3 million.

FERC Account	Description	1999	2000	2001	2002	2003	2004
56300	Overhead Lines Expenses	$ 281,922	$ 244,124	$ 311,697	$ 388,112	$ 574,937	$ 764,232
57100	Maintenance of Overhead Lines	2,785,423	1,685,562	2,643,844	3,084,258	2,453,216	3,414,493
	Subtotal Overhead Lines	$ 3,067,345	$ 1,929,686	$ 2,955,541	$ 3,472,370	$ 3,028,153	$ 4,178,725
	Circuit miles of line - Overhead	1637.4	1637.4	1637.4	1637.4	1637.4	1637.4
	Cost per circuit mile - Overhead	$1,873	$1,179	$1,805	$2,121	$1,849	$2,552
56400	Underground Lines Expenses*	N/A	N/A	103	200,205	195,552	300,588
57200	Maintenance of Underground Lines*	N/A	N/A	127,625	162,267	129,518	140,318
	Subtotal Underground Lines			$ 127,729	$ 362,472	$ 325,070	$ 440,906
	Circuit miles of line - Underground	43.0	43.0	43.0	43.0	43.0	43.0
	Cost per circuit mile - Underground			$2,970	$8,430	$7,560	$10,254

* Excluding costs related to submarine cable.
N/A Not available

Witness: CL&P Panel
Request from: Connecticut Siting Council

Question:
Provide the overhead transmission line capital costs ($/mile) that CL&P uses to compare alternative single circuit line structures and designs for 115 kV and 345 kV lines of the following types:
- Wood pole
- Steel pole
- Steel towers

If possible, please break these costs into the following categories:
- Conductors
- Towers/supporting structures
- Land costs
- Insulation costs
- Other (please specify)

If the costs are not available for all of these categories, please provide them in as much detail as possible for the categories CL&P routinely uses.

Response:
115 kV

Overhead Route (115 kV Delta Wood Laminate Pole)	
LENGTH (Miles)	1.0
Description: Single Circuit 115kV 1590Conductor	
ITEM	**COST**
POLES/Foundations	$298,025
CABLE/Hardware	$337,256
SITE WORK	$90,802
MISC CONSTRUCTION COSTS	$157,524
ENGINEERING	$61,536
SALES TAX (4.6%)	$43,477
NU Administration/Project Management	$98,862
TOTAL ESTIMATED OH COST/MILE	$1,087,482

Overhead Route (115 kV Delta Steel Pole)	
LENGTH (Miles)	1.0
Description: Single Circuit 115kV 1590 Conductor	
ITEM	COST
POLES/Foundations	$642,135
CABLE/Hardware	$337,256
SITE WORK	$90,802
MISC CONSTRUCTION COSTS	$247,790
ENGINEERING	$168,755
SALES TAX (4.6%)	$68,390
NU Administration/Project Management	$155,513
TOTAL ESTIMATED OH COST/MILE	$1,710,641

345 kV

Overhead Route (345 kV H-Frame)	
LENGTH (Miles)	1.0
Description: Single Circuit 345kV Bundled 1590 Conductor	
ITEM	COST
POLES/Foundations	$661,375
CABLE/Hardware	$560,032
SITE WORK	$183,300
MISC CONSTRUCTION COSTS	$301,809
ENGINEERING	$104,339
SALES TAX (4.6%)	$83,299
NU Administration/Project Management	$189,415
TOTAL ESTIMATED OH COST/MILE	$2,083,570

Overhead Route (345 kV Delta Steel Pole)	
LENGTH (Miles)	1.0
Description: Single Circuit 345kV Bundled 1590 Conductor	
ITEM	COST
POLES/Foundations	$1,814,372
CABLE/Hardware	$560,230
SITE WORK	$183,300
MISC CONSTRUCTION COSTS	$546,869
ENGINEERING	$176,445
SALES TAX (4.6%)	$150,936
NU Administration/Project Management	$343,215
TOTAL ESTIMATED OH COST/MILE	$3,775,366

CL&P has not built new transmission lines with Lattice Steel Structures for several decades, so we do not have any current data to support costs for these types of design. We have not attempted to estimate land rights costs because they are site and project specific and highly variable. Where existing CL&P right-of-way is available, they can be zero.

The Connecticut Light and Power Company
Docket No. LIFE-CYCLE 2006

Data Request CSC-01
Dated: 11/23/2005
Q- CSC-003

Witness: CL&P Panel
Request from: Connecticut Siting Council

Question:
Provide the same information requested in the previous question for double circuit structures and lines.

Response:

Overhead Route (115 kV Laminate Wood Pole)	
LENGTH (Miles)	1.0
Description: Double Circuit 115kV 1590 kcmil	
ITEM	**COST**
POLES/Foundations	$324,025
CABLE/Hardware	$774,478
SITE WORK	$121,805
MISC CONSTRUCTION COSTS	$263,045
ENGINEERING	$94,919
SALES TAX (4.6%)	$72,600
NU Administration/Project Management	$165,087
TOTAL ESTIMATED OH COST/MILE	$1,815,959

Overhead Route (115 kV Steel Pole)	
LENGTH (Miles)	1.0
Description: Double Circuit 115kV 1590 kcmil	
ITEM	**COST**
POLES/Foundations	$718,255
CABLE/Hardware	$774,478
SITE WORK	$121,805
MISC CONSTRUCTION COSTS	$347,130
ENGINEERING	$121,111
SALES TAX (4.6%)	$95,808
NU Administration/Project Management	$217,859
TOTAL ESTIMATED OH COST/MILE	$2,396,444

CL&P does not have recent data for double circuit 345-kV line designs. Because the loss of both lines on a double circuit structure is considered a single contingency event in reliability planning, CL&P expects to see less use of 115-kV double circuit transmission line designs in the future. No cost estimates were provided for 345-kV double circuit transmission lines on a common structure because the risks associated with the loss of both 345-kV transmission lines for a single contingency has too great an impact on system reliability.

Witness: CL&P Panel
Request from: Connecticut Siting Council

Question:

Provide the underground transmission line capital costs ($/mile) that CL&P uses to compare alternative 115 kV and 345 kV lines of the following types:

- High pressure fluid filled (HPFF)
- Cross-linked polyethylene (XLPE)

If possible, break these costs into the following categories:

- Cable costs
- Piping and associated supporting structures
- Conduit costs
- Other supporting structures
- Land costs
- Installation costs
- Other (please specify)

If the costs are not available for all of these categories, provide them in as much detail as possible for the categories CL&P routinely uses.

Response:

Underground Proposed Route (115kV XLPE)	
LENGTH (Miles)	**1.0**
Description: 115kV 3000 kcmil XLPE. 1 circuit, 1 cable per phase	
Item	Cost
DUCT/Vaults	**$4,573,084**
CABLE/Hardware	**$2,800,725**
SITE WORK	**$611,780**
MISC CONSTRUCTION COSTS	**$823,186**
ENGINEERING	**$246,272**
SALES TAX (4.6%)	**$416,532**
NU Administration/PM	**$947,158**
Total Project Cost/MILE	**$10,418,737**

Underground Proposed Route (345kV XLPE)
LENGTH (Miles) **1.0**

Description: 345kV 3000kcmil XLPE 2 circuits, 1 cable per phase, 3 splices per vault

Item	Cost
DUCT/Vaults	**$5,133,353**
CABLE/Hardware	**$8,469,288**
SITE WORK	**$617,838**
MISC CONSTRUCTION COSTS	**$1,517,070**
ENGINEERING	**$950,224**
SALES TAX (4.6%)	**$697,852**
NU Administration/PM	**$1,738,562**
Total Project Cost/MILE	**$19,124,187**

Underground Proposed Route (345kV HPFF)
LENGTH (Miles) **1.0**

Description: 345kV 2500 kcmil HPFF 2 circuit, 1 cable per phase/circuit

Item	Cost
DUCT/Vaults	**$3,786,400**
CABLE/Hardware	**$3,686,500**
SITE WORK	**$171,500**
MISC CONSTRUCTION COSTS	**$764,440**
ENGINEERING	**$252,265**
SALES TAX (4.6%)	**$398,411**
NU Administration/PM	**$905,952**
Total Project Cost/MILE	**$9,965,468**

Note: The 345-kV HPFF Underground line will require a pressurization plant at each end of the line at an approximate total cost of $5.3M. This cost has not been included in the above per-mile 345-kV HPFF estimate.

A current cost estimate for a 115-kV HPFF cable system is unavailable. The cost estimates above are based upon recent work on the Middeltown-Norwalk transmission project.

Land costs are site and project specific. Most often, underground lines will be built within road right-of-ways, but some parts of a line (e.g., vaults) may be forced onto private property by state DOT or local community requirements. Future significant costs may be incurred by CL&P if the state requires existing underground cable systems to be relocated within or outside Connecticut DOT rights of way.

345-kV cable systems have high charging currents which for typical circuit lengths will require compensation by shunt reactors. These shunt reactors would be located at the terminal substations of an underground 345-kV circuit, or at line transition stations built specifically for transitions between overhead and underground segments of a 345-kV circuit. The initial and ongoing costs of these shunt reactors and associated equipment is not included in the above estimates for 345-kV cable lines.

Witness: **CL&P Panel**
Request from: **Connecticut Siting Council**

Question:
The 2001 Acres Report states that "Figures supplied by the Connecticut Light and Power Company indicate that their operation and maintenance (O&M) costs for overhead (115- kV transmission 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." Estimate the O&M costs per circuit-mile for overhead and underground 115-kV and 345-kV transmission as applicable for the years 1999 through 2004.

Response:
Please see the table attached to the response to Data Request CSC-01, Q-CSC-001 for summary data on the average operating and maintenance costs per circuit-mile of CL&P overhead and underground lines for the years 1999-2004. The Underground Transmission O&M costs are readily available only for the years 2001-2004.

The Connecticut Light and Power Company
Docket No. LIFE-CYCLE 2006

Witness: **CL&P Panel**
Request from: **Connecticut Siting Council**

Question:
In the May 2001 Life-Cycle Report by Acres International Corp. (2001 Acres Report) , the Executive Summary contains the following statement regarding wood pole preservatives, "There is a possibility that the most commonly used preservative, penta (pentachlorophenol), may be banned by the EPA. If this occurs, then more costly steel poles may have to be used as a replacement for Western Red Cedar poles pending the development of a substitute acceptable preservative."

a) Has Penta been banned by the EPA?
b) If yes, what replacement preservative is currently being used?
c) How might the life-cycle costs be affected for wood structures due to the newer preservative if available?

Response:
a) Penta has not been banned by the EPA and remains available for use as a wood pole preservative.

b) None, as CL&P continues to use Penta. However, waterborne arsenic salts CCA, ACZA, ACA, etc. are alternative preservatives for some wood species, but they tend to harden the wood and do not penetrate as deeply as oil-based products. Aresnic salts are not an alternative for Western Red Cedar, the species CL&P uses for transmission construction. CL&P is watching with interest to learn whether treatment type is suspect in the reported widespread pole breakage experienced in the southern U.S. during the 2005 hurricanes.

c) There is no other alternative treatment for Western Red Cedar, so new or replaced poles would likely have to be glue-laminated Southern Yellow Pine columns, and glue-laminated columns or poles of Douglas Fir. Higher first cost and/or shorter service life would increase the life-cycle cost for lines with wood structures.

The Connecticut Light and Power Company
Docket No. LIFE-CYCLE 2006

Data Request CSC-01
Dated: 11/23/2005
Q- CSC-007

Witness: **CL&P Panel**
Request from: **Connecticut Siting Council**

Question:
The 2001 Acres Report also states that, "Transmission lines are built to provide safe reliable performance over a life of 35 to 40 years." Is that estimated lifespan still used for transmission life-cost analysis?

Response:
Yes. The estimated lifespan used for transmission life-cost analysis is 40 years. Transmission lines have reliably and safely performed for longer periods if well maintained and with life-extending component replacements (e.g., wood crossarms, shield wires, conductor splices).

The Connecticut Light and Power Company
Docket No. LIFE-CYCLE 2006

Data Request CSC-01
Dated: 11/23/2005
Q- CSC-008

Witness: CL&P Panel
Request from: Connecticut Siting Council

Question:
The July 1996 Life-Cycle Report by Acres International Corp. (1996 Acres Report) on page C-29, states that (for 115-kV transmission) the following life expectancies exist for the following transmission lines:

- Wood Pole 40 years
- Steel Pole 60 years
- Underground Cable 35 to 40 years

a) Does CL&P agree with these life expectancies?
b) If not, what typical life expectancies would CL&P use for each of these transmission types?
c) Please provide similar life expectancies for 345 kV transmission lines of the same types.
d) Please provide the life expectancies for both 115 kV and 345 kV underground lines using both HPFF and XLPE cable.

Response:
a) Yes
b) N/A
c) The life expectancies for 345-kV transmission lines would be the same as for 115-kV lines using similar materials.
d) The life expectancies for both 115-kV and 345-kV underground HPFF cable systems are 35 to 40 years. Second generation solid dielectric cable systems in the 115- to 170-kV class have been in-service for approximately 20 years; their performance to date indicates that we can reasonably expect their life expectancy to be 35 to 40 years. The first 345- to 500-kV XLPE cable systems were installed primarily in large tunnels in the late 1990s. CL&P will be installing the first long length of 345-kV XLPE cable system in the United States next year. The CL&P installation will be in duct banks for which there is limited worldwide experience. With only limited worldwide experience, it if far too early to predict with certainty the life expectancy of 345-kV XLPE cable systems.

The Connecticut Light and Power Company
Docket No. LIFE-CYCLE 2006

Data Request CSC-01
Dated: 11/23/2005
Q- CSC-009

Witness: **CL&P Panel**
Request from: **Connecticut Siting Council**

Question:
Are polymer insulators the preferred type of insulators? Have they largely replaced porcelain or glass insulators?

Response:
The industry has not universally moved to polymer insulators as the preferred type. Utilities often decide between porcelain, glass, and polymers based upon the specific circumstances of the application. For example, CL&P installs polymer insulators on new 115-kV lines where their slightly longer length and associated greater vertical spacing between arms will allow it (e.g., on the Canton-Weingart Junction project). Otherwise, strings of porcelain disc insulators are used (e.g., on the Rowayton-Glenbrook reconductor project). CL&P has not used toughened glass insulators in many years. At 345 kV, the longer length of electrically-equivalent polymers and the hardware necessary for energized maintenance would not fit CL&P's standard vertical- and delta-configurations of structures without increasing their phase spacings, so CL&P has continued to use porcelain disc insulators on such lines (e.g., on the Bethel-Norwalk project). Another consideration with polymer insulators is that live-line techniques have not been fully developed,. Therefore, most utilities (including CL&P) do not perform live-line maintenance on lines constructed with polymer insulators at this time.

The Connecticut Light and Power Company
Docket No. LIFE-CYCLE 2006

Data Request CSC-01
Dated: 11/23/2005
Q- CSC-010

Witness: **CL&P Panel**
Request from: **Connecticut Siting Council**

Question:
Describe how leak prevention and containment measures used on high-pressure fluid- filled cable systems could impact life-cycle costs.

Response:
Leak-prevention measures have always been integrated into the design of HPFF systems, and would have been reflected in the CSC's 1996 study cost estimates. Leak prevention starts with a high-quality corrosion coating of the pipe, careful testing of the coating several times during the construction operations, and placing a high-quality backfill around the pipes. A cathodic protection system is provided to protect the pipe in the event of unknown or unreported damage to the pipe's corrosion coating. The pipe coating and the cathodic protection system are included in periodic maintenance procedures for the line to maintain the quality of the leak-prevention systems. Measures to reduce fluid loss consist of containment volumes designed into foundations under the pump plant/fluid expansion tank enclosures. Also included are a variety of pressure gauges and alarms to detect low fluid pressure or frequently-operating pumps that might indicate a leak in the system, and valves to isolate appropriate portions of the system. Despite these measures, industry experience has shown that fluid spills do occasionally occur with HPFF systems, and can result in significant clean-up costs.

Any additional mechanical protection or containment measures, or leak-detection systems, that are installed with the intention to reduce the frequency and extent of HPFF fluid leaks would add significantly to the initial capital cost, and, consequently, to the life-cycle cost of HPFF cable systems, because of both the initial and ongoing operating and maintenance costs of such measures. Because of the very low frequency of leaks, any resulting lower O&M cost of leak repair and remediation would not compensate for the extra capital cost, and therefore the total life-cycle cost would be higher.

Witness: **CL&P Panel**
Request from: **Connecticut Siting Council**

Question:
Has CL&P researched or evaluated the use of composite conductors for transmission lines to increase line capacity? If so, what is estimated life cycle cost impact? Please break into first cost and ongoing cost elements.

Response:
Yes. CL&P has conducted an extensive worldwide review of composite conductor technology and believes the implementation of this technology can increase the ampacity of an existing transmission line without having to replace the majority of the transmission structures. The cost of the composite conductors is significantly greater than that of Aluminum Conductor Steel Reinforced (ACSR) or Aluminum Conductor Steel Supported (ACSS) transmission conductors. On a new transmission line, the use of composite conductors to achieve a higher current-carrying capability would be extremely difficult to cost justify. On an existing transmission line where the existing structures would have to be replaced to accommodate larger ACSR or ACSS conductors, composite conductors may be cost justified. CL&P would not install a composite conductor on a critical transmission line and operate it at the manufacturer's designated maximum normal and emergency operating temperatures until it has seen in-service and laboratory data which validate the manufacturer's technical literature.

The primary manufacturers of composite conductor technology are in North America and Japan. The United States manufacturers are: Composite Technology Corporation and the 3M Corporation. Composite Technology Corporation (in partnership with General Cable) manufactures an Aluminum Conductor Composite Core (ACCC) conductor. The 3M Corporation (in partnership with Nexans/Canada) manufactures an Aluminum Conductor Composite Reinforced (ACCR) conductor. Both United States manufacturers have worked with reputable North American transmission line hardware manufacturers and have a full line of full tension compression splices, compression and formed wire dead ends, suspension clamps, high temperature inhibitor and motion control accessories. We know of no North American transmission lines which utilize composite conductors manufactured in Japan.

Composite conductors are able to carry higher continuous and emergency current levels because the conductor has the ability to operate at appreciably higher temperatures without causing permanent damage. And in high temperature operation, composite conductors do not elongate and sag to the degree other conductors do, such that required conductor-to-ground clearances are not violated. CL&P currently designs its Aluminum Conductor Steel Reinforced (ACSR) transmission lines to operate at a maximum temperature of 100 degrees C under normal conditions and a maximum temperature of 140 degrees C under emergency conditions. Its Aluminum Conductor Steel Supported (ACSS) transmission lines are designed to operate at maximum temperature of 100 degrees C and 180 degrees C, normal and emergency conditions respectively. CTC states that its conductor can operate at a maximum design temperature of 200 degrees C; 3M states that its conductor can be operated at 240 degrees C.

The cost of the composite conductors and hardware is appreciably greater than ACSR or ACSS aluminum conductors, and there are a number of special handling requirements which increase the conductor installation costs. The cost of 3M composite conductor is 3 to 30 times that of ACSR or ACSS conductor, varying with the length of conductor purchased: the longer the conductor, the lower the conductor cost per mile. The manufacturers are signing confidentiality agreements with those utilities who have purchased their conductors; therefore, it has not been possible to determine the cost per mile to install this technology.

It is impossible to determine the life cycle cost of any composite conductor at this time because no composite conductors have been in service for more than one year. The life expectancy for these conductors is not yet known. A second factor is that the composite conductors have not been operated at their maximum normal or emergency temperatures for any extended period of time. Utilities that have installed the composite conductors are operating the facilities at conservative temperatures until they gain appreciably more experience with this new technology. We know that when composite conductors are operated in the higher temperature ranges, power losses (I^2R) will significantly increase and become an important consideration in life-cycle costing. The expectation of the utility industry is that composite conductors would not require greater maintenance than transmission lines with ACSR or ACSS conductors. However, since there is very little operating experience with either of these conductor technologies, and there still remain a number of unanswered questions, it is difficult to anticipate the maintenance costs that would be associated with a composite conductor transmission line. CL&P is continuing to closely monitor the developments of this new conductor technology.

Witness: **CL&P Panel**
Request from: **Connecticut Siting Council**

Question:
Has CL&P experienced, in the last five years, issues with construction or maintenance of transmission lines in locations that required special processes or procedures due to environmental sensitivity? If so, please describe the situations and the cost impacts.

Response:
CL&P has experienced issues with construction and maintenance of transmission lines in locations that have required special processes or procedures due to environmental sensitivity in the last five years. A summary of the general issues and associated cost impacts follow:

Extra precautions and Best Management Practices (BMP's) are used in wetland areas and for storm water management - erosion and sediment control. For example, swamp mats are used when vehicles require access to minimize damage to wetland areas per local, state and federal regulations. Stormwater management controls are required per state and federal regulations during maintenance and construction activities.

<u>Wetland Area Protection</u>

- Swamp mats
  - $4.80/square foot installed
  - Specific example - Berlin-Farmington shield wire replacement project:
  - 9,000 square feet of swamp mats deployed: $43,500 (size of each mat:7' X 12' X 8")
  - Average work size requiring swamp mats (11,000 square feet) would cost $52,000
- Temporary fill
  - $1.70/cubic foot installed

<u>Stormwater Management</u>

- Silt fences
  - $3.00/linear foot installed
- Hay bales
  - $6.00/linear foot installed
- Culverts
  - $2,000/pipe installed (steel corrugated - 18" X 20')
- Site restoration (grading, mulch, seeding, etc.)
  - $3,500/acre

State regulations and requirements require special handling and disposal of contaminated and/or polluted soil and water encountered during excavation activities for overhead and underground facilities.

<u>Soil disposal (polluted/contaminated)</u>

- $36.00/ton (average)
- BN 345 project: approximately $4 million to date

Water disposal (polluted/contaminated) from dewatering activities

- $0.20/gallon (average)
- BN 345 project: $100,000 (estimated to date)

Soil & water lab testing

- Lab testing: TBD (varies)
- BN 345 project: TBD

Endangered Species Protection (state & federal)

- Negligible cost effects

Jack & Bore or Directional Drilling Operations (under wetlands or water bodies)

- $1,850/foot (average) with no rock
- 300-foot operation: $555,000
- $3,850/foot (average) with rock
- 300-foot operation: $1,155,000

The reduction of magnetic field exposures is sometimes considered to be an "environmental" issue. While CL&P has not yet incurred extra construction costs to meet the requirements of P.A. 04-246 for minimizing magnetic field exposure in certain "sensitive" areas, it expects that such costs will be extensive."

Also, while not an environmental issue and not yet incurred, CL&P notes that the splicing and repair of underground XLPE transmission cables is a special process requiring specialized labor resources from overeas suppliers of these cables and splices.

The Connecticut Light and Power Company
Docket No. LIFE-CYCLE 2006

Data Request CSC-01
Dated: 11/23/2005
Q- CSC-013

Witness: **CL&P Panel**
Request from: **Connecticut Siting Council**

Question:
ISO-New England (ISO-NE) has issued planning and operating standards for design and operation of transmission facilities. One standard prescribes transmission line ratings for normal conditions, short-term emergency and long-term emergency conditions. Does CL&P expect the standards to impact transmission line life-cycle costs, and if so, to what extent?

Response:
CL&P assumes the question is primarily addressing rating procedures for transmission equipment and not New England transmission system planning and operating procedures. CL&P expects that these rating pocedures will not impact the life-cycle costs of a particular transmission line, just its capacity.

Since the early 1970's New England's electric utilities have followed NEPOOL guidelines to rate transmission equipment. Each transmission component shall have a Normal, Long-time Emergency (LTE) and Short-time Emergency (STE) ratings, one set for summer months and another set for winter months. For the NU Transmission System, STE ratings are generally used in emergency operations and not for a system planning purpose. Plans for the NU Transmission System are based on the Normal and LTE ratings. Normal ratings are used to assess the system under all-lines-in conditions. LTE ratings are used to assess the system under contingency conditions which are specified in national and regional planning standards..

Recently, ISO-NE developed Planning Procedure No. 7 (PP7) to re-evaluate the existing methods and procedures to rate transmission equipment. This planning procedure was developed in part to address NERC-approved reliability compliance standards. The rating assumptions and requirements are similar to those used by CL&P over the past 30 years, so only slight variations in equipment ratings could result from this re-evaluation.

These rating guidelines can affect life-cycle cost comparisons between overhead and underground transmission lines by making it hard to identify equal-capacity alternatives for a fair comparison. For example, two or three underground cables in parallel can be needed to achieve a Normal or LTE rating that can be achieved by a single overhead line with standard conductors.

The Connecticut Light and Power Company
Docket No. LIFE-CYCLE 2006

Data Request CSC-01
Dated: 11/23/2005
Q- CSC-014

Witness: CL&P Panel
Request from: Connecticut Siting Council

Question:
Has CL&P identified other ISO-NE policies or operating procedures that are anticipated to impact transmission line life-cycle costs? If so, what are they and what is the anticipated impact?

Response:
CL&P is not aware of new ISO-NE policies or operating procedures that are anticipated to impact transmission line life-cycle costs.

On August 8, 2005 President Bush signed into law the Energy Policy Act of 2005 ("Act") that gives FERC new responsibilities in overseeing the reliability of the nation's electricity transmission grid with enforceable and mandatory reliability rules. On September 1, 2005 FERC issued a Notice of Proposed Rulemaking ("NOPR") on *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards* to begin implementation of the Act. Under the Act, a new national reliability organization called the Electric Reliability Organization ("ERO") will be responsible for developing national Reliability Standards subject to FERC approval and will have the authority to impose sanctions and penalties on those who violate the Reliability Standards. Until such time as ERO standards are approved and implemented, CL&P is unable to determine the impact on transmission line life cycle costs.

The Connecticut Light and Power Company
Docket No. LIFE-CYCLE 2006

Witness: **CL&P Panel**
Request from: **Connecticut Siting Council**

Question:
Under what conditions would the Connecticut Light and Power Company (CL&P) consider using high voltage direct current (HVDC) lines for long-distance power transfers? How would the life cycle costs of HVDC lines compare to alternating current (AC) transmission lines?

Response:
CL&P would consider using high voltage direct current ("HVDC") lines for long distance power transfers if the resulting system adequately meets reliability needs in a cost-effective manner. CL&P's evaluation would consider several factors, including:

- the operating flexibility needed to meet the dynamic needs of the electric grid in the near and long term;
- future flexibility in planning an electrical system, recognizing that peak load demands by location may not always be predictable, and also that in the new competitive generation marketplace, decisions to locate new generation or to retain existing generation are based on market forces, not always with due respect to customer service needs and electric reliability requirements; and
- the long-term availability of replacement equipment to avoid long duration line outages;

HVAC and HVDC lines are typically not equal technical alternatives for meeting transmission grid needs. There are some applications of long-distance, point-to-point transfers where a two-terminal HVDC line is the only realistic solution, regardless of life-cycle cost comparisons with an HVAC line. An example in recent Connecticut history is the Cross Sound HVDC cable system. Two terminals and long distances are the key application conditions for considering HVDC lines. For other applications within an AC transmission system, an HVDC line is seldom preferable to an HVAC line.

The distances typically involved with "long-distance power transfers" are hundreds of miles. Examples of long HVDC lines in service include the Quebec to New England ± 450kV line, and a Pacific intertie line between California and Oregon. While the installation cost/mile of an overhead HVDC line can be a bit less than for equivalent capacity HVAC line, this cost savings can only offset the much higher HVDC terminal costs when a line is hundreds of miles long. Therefore, overhead HVDC lines have primarily been used for special long-distance system intertie applications, point-to-point.

For underground line applications, there's another consideration. The length of underground HVAC cable installations is limited by the charging current requirements of cables. High charging currents reduce the power-transfer capacity of a cable system , and can lead to system harmonic resonance issues if located within weak or moderate strength transmission systems. At CL&P's transmission voltages, 115-kV AC cable lengths may practically be limited by such considerations to about 25 miles, and a lower distance limit would apply for 345-kV lines. Compensating reactor stations can be installed at intervals along HVAC transmission cables to expand these distances, but this becomes impractical for long water crossings (e.g., the Cross Sound Cable length). HVDC cables can therefore be the only choice for such crossings. For shorter underground line applications within Connecticut where HVAC cables can be practical, a lower cost to construct an HVDC line will not offset the high terminal converter costs.

For a system need that could be resolved by either an HVDC line or an HVAC line, a comparison of life-cycle costs will depend upon several important factors including the length of each line, the number of termination stations, the amount and availability of land needed for converter and termination stations, the expected asset lives and maintenance costs, whether the lines are overhead or underground, and loss differences. Such a comparison should also consider future costs associated with lost future flexibility to change or expand the electric grid to meet new system or customer needs..