STATE OF CONNECTICUT

CONNECTICUT SITING COUNCIL

CONNECTICUT SITING COUNCIL INVESTIGATION INTO THE ELECTRIC TRANSMISSION LINE LIFE-CYCLE COSTS	: : :	LIFE CYCLE 2011 APRIL 19, 2012

COMMENTS OF THE CONNECTICUT LIGHT AND POWER COMPANY ON DRAFT REPORT

The Connecticut Light and Power Company (CL&P) respectfully submits the following detailed comments on the Draft Report (Draft) issued by the Connecticut Siting Council (Council) on March 20, 2012. CL&P appreciates the opportunity to review and provide comments on the Draft. The Draft is a comprehensive report that reflects the substantial undertaking of data gathering and analyses by the Council, Council staff, its consultants, and the participants in this proceeding. CL&P has carefully reviewed the draft and offers the following comments in an effort to address specific items that may benefit from additional clarification, explanation or revision.

Section/Page/Para./ Figure/Table	Specific Comments
Section 2, P. 2-3 to 2-6, Figures 2-1 to 2-4	Each of the referenced Figures is a pie chart that provides percentage breakdowns for different cost elements of the life-cycle costs. Each figure uses an energy cost of 10 cents/kWh, which is the same energy cost that was used in the 2007 Life Cycle Report. However, CL&P notes, as Mr. Carberry explained during the January 17, 2012 hearing (Transcript at 11-13), that actual 2011 hourly energy cost data is available on the ISO-New England's website at: http://www.iso-ne.com/markets/hstdata/znl_info/hourly/index.html Using the data on this website, the real time locational marginal price of energy in Connecticut, averaged across all hours in 2006, was approximately 6.45 cents/kWh. In comparison, the real time locational marginal price of energy in Connecticut, averaged for all hours in 2011, was approximately 4.79 cents/kWh. Thus, the ISO-

	New England's actual hourly data show a decrease in the average energy price in Connecticut between 2006 and 2011 of approximately 1.66 cents per kWh. CL&P recommends that the 2012 Transmission Line Life-Cycle Cost Report provide a data source for the presumed energy costs that are used in calculating the Life-Cycle costs shown in the Report. CL&P also suggests that a downward adjustment to the cost of energy to be used in 2012 Report (from the energy cost used in the 2007 Report) seems warranted to reflect the general decrease in the actual cost of electricity over this five-year period.
Section 3.2, P. 3-2, First full paragraph, third sentence	This sentence states: "These differ significantly from the 2007 report, however, because the designs investigated in the [2007] report were based on the use of ACSR conductors, whereas these five designs all employ ACSS conductors." If the word "these" in this sentence refers to the "first costs" of overhead lines, CL&P notes that there are several factors (other than the change in conductors) that contributed to the change in first costs between 2006/2007 compared to 2011/2012. Such other factors would include changes in the costs of materials, fuel, and labor, to name just a few.
Section 3.2, P. 3-2, Fourth full paragraph	This paragraph states that the Connecticut utilities no longer use wood laminate poles for overhead transmission line construction. This statement should be revised to state that the Connecticut utilities do not commonly use wood laminate poles for overhead lines. For new H-Frame structures, CL&P's preference is to use natural wood for new 115-kV H-Frame structures and direct buried tubular steel poles for new 345-kV H-Frame structures. However, if wood construction were required for a particular 345-kV H-Frame structure, the structure would most likely be constructed using wood laminate poles. In CL&P's recent siting application to the Council relating to the Interstate Reliability Project, CL&P explained that the new 345-kV H-Frame structures would be constructed using steel poles or laminated wood poles. See, for instance, Docket 424, Application, Vol. 1, p. ES-12. Further, CL&P believes that the cost difference between direct buried tubular steel and wood laminate 345-kV H-Frame structures of the same height would be relatively small. Consequently, it may be simpler and preferable to revise all the references in the 2012 Life-Cycle Costs Final Report to 345-kV H-Frame structures to eliminate specification of wood or steel and simply refer to a "345-kV H-Frame Structure" instead.
Section 3.2, P. 3-3, 3-4, Bullets on P. 3-3 & Tables 3-2 to 3-4	In the sixth bullet on page 3-3, the actual tax rate that is reflected in the Sales Tax dollar amounts shown in Tables 3-2 to 3-4 is the current "blended" rate of 4.13%, rather than 4.6%; therefore, "4.6%" should be deleted and replaced with "4.13%" in this bullet. In addition, the text of this bullet should explain that 4.13% is the

	current "blended" sales tax rate, which is applied to the aggregate cost of taxable and tax-exempt purchases of services, equipment and materials from suppliers and contractors.
Section 3.2, P. 3-4, paragraph of text above Table 3-4, last sentence	This sentence states: "A wood H-Frame structure with horizontal conductor spacing results in a 42% lower cost per mile when compared with using single steel poles." To clarify, CL&P recommends that this sentence be revised to state: "A 345-kV H-Frame structure with horizontal conductor spacing results in a 42% lower cost per mile when compared to using a single steel pole structure with a Delta configuration."
Section 3.3, P. 3-6, single sentence on page	This sentence refers to the seven underground transmission designs described in Table 3-5 as designs that have been used in Connecticut. This sentence is incorrect because only some, but not all, of these seven designs have been used in Connecticut. The sentence should be revised to state that the seven designs are the designs that may be considered for future applications in Connecticut.
Section 3.3, P. 3-7, paragraphs immediately above and below Table 3-6	The second sentence in the paragraph immediately above Table 3-6 has a typo – "CP&L" should be replaced with "CL&P". Further, Table 3-6 compares the total cost per mile of 3000 kcmil 115-kV HPFF cable (Delta – One cable per phase) to the cost per mile of 3000 kcmil 115-kV XLPE cable (Horizontal – One cable per phase). The sentence immediately below the table states that total XLPE cable system cost is 46% per mile higher than HPFF cable system cost. This cost comparison is somewhat distorted because the cost per mile of HPFF cable does not account for the additional cost that would be required for pressurization plants to support an HPFF cable and potential of additional costs for increased shunt compensation needed for HPFF cable. In addition, the HPFF cable may either have reduced capacity as compared to XLPE cable (of the same size) or require additional costs for equipment to circulate the fluid used in the HPFF cable in order to achieve equivalent capacity. Text further below in this Section 3.3 notes that Chapter 5 discusses other factors including pressurization plants and shunt reactors and their associated costs.
Section 3.3, P. 3-8, paragraph at top of page, first sentence Section 3.3, P. 3-8, paragraph immediately below Table 3-7	A space between "345 kV" and "underground" should be inserted. Table 3-7 compares the total cost per mile of 3000 kcmil 345-kV HPFF cable (Delta – One cable per phase) to the cost per mile of 3000 kcmil 115-kV XLPE cable (Delta/Horizontal – One cable per phase). The sentence immediately below the table states that the total XLPE cable cost is 32% per mile higher than HPFF cable. Again, this cost comparison is somewhat distorted because the cost per mile of HPFF cable does not include the additional cost that

	would be required for pressurization plants for HPFF cable and the potential for additional shunt compensation costs. And, the HPFF cable may have reduced capacity as compared to the XLPE cable or additional costs for circulating equipment to increase the HPFF cable capacity.
Section 3.3, P. 3-9, paragraph immediately below Table 3-8.	The sentence immediately below Table 3-8 refers to the data in Table 3.8 (rather than Table 3-7 as stated in the sentence), so this reference should be corrected to Table 3-8. Further, this sentence states that the total XLPE cable cost is 32% per mile higher than HPFF cable. As noted above, this cost comparison is somewhat distorted because it does not account for additional cost required for pressurization plants, potential increased costs for shunt compensation and reduced HPFF cable capacity or increased costs for fluid circulating equipment.
Section 4.2.1, P. 4-3, paragraph immediately above Section 4.2.2.	Last sentence of this paragraph should be revised as follows because the quoted statement was made by CL&P's witness in 2006 (suggested inserts are noted by italicized letters): As noted *in 2006* by Graham McTavish, *former* 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."
Section 4.2.2, P. 4-3, paragraph immediately below bullet points.	Last sentence of this paragraph states that if the transmission line needs to cross rivers or streams "a number of special foundations are typically required." CL&P is not sure what type of "special foundations" are contemplated and suggests that this sentence be revised to explain the likely effects resulting from such river or stream crossings -- longer spans between transmission line structures, which would require taller and stronger structures and associated larger foundations, both of which would lead to increased costs.
Section 4.3, P. 4-5, third paragraph	First sentence in the quotation should be revised as follows: "Five years ago I don't think there was such a thing [as a Solution report]."
Section 4.3.2, P. 4-7, last paragraph, last sentence	The word "design" in this sentence should be deleted so that the sentence reads: "This is another limiting consideration for underground cable systems."
Section 4.3.4, P. 4-8, second to last sentence of section	This sentence indicates that the USACE permits "may take up to a year" to obtain. However, CL&P notes that the USACE permit for its Greater Springfield Reliability Project and Manchester to Meekville Project actually took 27 months to obtain. Accordingly, the sentence could be revised to state as follows: "These permits, which may take a year or even significantly longer to obtain, are typically done in connection with other permits granted by the

	Council and/or DEEP."
Section 4.4, P. 4-9, fourth sentence of section second full paragraph.	This sentence references the quotation from Mr Carberry's 2006 Pre-Filed Testimony. Therefore, this sentence should be revised as follows (suggested insertion in italicized letters): "As an example for a recent project in Connecticut, Mr. Carberry stated *in 2006*: In the comparison…." [continue as included in the Draft]
Section 5.2, P. 5-3, paragraph beneath Figure 5-1.	The paragraph on page 5-3 refers to Table 5-1 to make the point that "the most expensive alternative was a hybrid line." However, there is no hybrid line described in Table 5-1. Option 1 in that table would have replaced an existing overhead 115-kV line from Plumtree to Peaceable and from Peaceable to Norwalk with an overhead double-circuit (345- and 115-kV) line, with ROW expansion. Option 2 would have replaced the existing overhead 115-kV line from Plumtree to Peaceable and from Peaceable to Norwalk with underground cables so that an all-overhead 345-kV line could be built on the right-of-way. (The reference in the top line item of Option 2 to overhead 115-kV from Norwalk Junction to Norwalk was to an adjacent double-circuit 115-kV line on this right-of-way segment that would have remained as it was, or would have been rebuilt, overhead alongside an overhead 345-kV line.) Option 3 would have built the 345-kV line entirely underground, with no changes to the existing overhead 115-kV line from Plumtree to Peaceable and from Peaceable to Norwalk. The cost estimates for these line options in Table 5-1 are also very much out of date compared to today's costs. Ultimately, the Bethel to Norwalk project was built with hybrid 115- and 345-kV lines, but these lines are not shown in Table 5-1. To make the point that hybrid line alternatives are more expensive, the Council and KEMA could refer to the ISO-NE's Transmission Cost Allocation (TCA) Decision on the Bethel-Norwalk project dated September 22, 2006. This decision can be found at the following link: http://www.iso-ne.com/trans/pp_tca/isone_app_approvals/tca/2006/sep/nu_phase1_tca_letter.pdf In this TCA decision (see Table 1 of the decision), ISO-NE determined that, excluding ancillary facility costs, the Bethel-Norwalk project could have practically and feasibly been built using all-overhead lines (ISO-NE's alternative 5a) for a cost of $258 million, including $81.3 million in substation costs and $44 million in ROW costs. These cost estimates also included an allowance for costs associated with project delays relative to the as-built project. In its decision, ISO-NE also determined that the

	estimated cost for the as-built project, excluding ancillary facility costs, would be $350 million, including $81.6 million in substation costs and $9.8 million in ROW costs. The as-built project included two double-cable underground sections (one HPFF and one XLPE) and two overhead sections in the new 345-kV line, and it included three overhead and two underground sections (XLPE) in the Plumtree to Peaceable 115-kV line and one overhead and one underground section (XLPE) in the Peaceable to Norwalk 115-kV line.
Section 5.2, P. 5-4, paragraph beneath Table 5-1.	The paragraph beneath Table 5-1 refers to the Middletown-Norwalk project to show higher costs for hybrid 345-kV lines. The Middletown-Norwalk project, however, did not include any hybrid 345-kV lines; consequently, this paragraph should be deleted. The 345-kV line scope of that project included two circuits of underground cables connecting the Norwalk and Singer Substations, two circuits of underground cables connecting the Singer Substation to a new East Devon Switching Station, one all-overhead circuit connecting the East Devon and Beseck Switching Stations, and three other sections of new overhead 345-kV line connecting to then-existing all-overhead line segments. Because no then-existing or new 345-kV circuit had both overhead and underground segments, there were also no line transition stations in this project. The total project cost of $1.27 billion also included some 115-kV line rebuilds, real estate costs and one short section of underground 115-kV line, the latter making one 115-kV circuit a hybrid line.
Section 6.2, P. 6-1, second paragraph, fifth sentence.	This sentence states that the electric system is "continuously exposed" to disturbances of varying severity. Because this type of disturbance is not continuously present, the word "continuously" should be deleted and replaced with either "frequently" or "routinely".
Section 6.2, P. 6-2, third bullet in first full paragraph.	This bullet refers to a category of operating costs that are "incurred as a result of constraints on the operation of the power transmission system". This item appears to reference costs caused by transmission system operating limits. If so, CL&P observes that a primary example of such costs would be costs associated with running "out-of-merit" generation. The cost of out-of-merit generation is not included or accounted for as a transmission operation cost expense. In addition, CL&P is not aware of what other types of costs might be included in this category. Thus, further review of this bullet item is warranted; and that review may result in revision, clarification, or deletion of this item.
Section 6.2, P. 6-2, paragraph immediately above Section 6.3, third	The third sentence refers to "large overruns of budgeted expenditures" that were caused by "unplanned" and "non-routine activities" such as line overloads, generating unit or major transmission forced outages, or storm conditions. CL&P does not

sentence.	understand how there would be "large overruns of budgeted" operating expenditures caused by these types of events. CL&P notes that costs associated with major storms would normally be charged to separate storm accounts, rather than transmission operating costs. CL&P would not expect that line overloads, generating unit or major transmission forced outages would cause "large overruns" of the operating cost budgets.
Section 6.3.1, P. 6-4, Sentence above, Figure 6.1 and Figure 6.1	The sentence above Figure 6-1 refers to increases in Overhead Transmission Line Maintenance Costs shown in Figure 6-1, while the labels underneath and within Figure 6-1 indicate that this Figure is showing Total Overhead Transmission Line O&M Costs ($/ckt-mi). In addition, the amounts shown in this Figure appear to be inconsistent with, and higher than, the amounts provided in responses to interrogatories filed in this proceeding. See, e.g., CL&P Response to CSC-01, Q-CSC-001 and UI Response to CSC-01, Q-CSC-005. CL&P suggests that the data shown in this Figure should be carefully reviewed,
Section 6.3.1, P. 6-4, bullets at the bottom of the page	A bullet for herbicide applications should be added here.
Section 6.3.1, P. 6-5, Figure 6.2	It appears that the CL&P and UI labels on the chart have been reversed. The labels should be switched.
Section 6.3.1, P. 6-5, paragraph below Figure 6.2, second sentence	This sentence states that the patrol frequency for 345-kV has increased from once per year to 3 patrols per year. These patrols actually were increased to 2 patrols per year. Consequently, the number "3" in this sentence should be deleted and replaced with the number "2".
Section 6.3.1, P. 6-5, last paragraph, first bullet	This bullet concerning LiDAR should be deleted because LiDAR does not provide or estimate temperature or loading of a transmission line. LiDar models the transmission line to show its relative locations under all possible operating conditions (maximum sag and sway conditions).
Section 6.3.1, P. 6-6, Figure 6.3	Figure 6-3 should be titled "Hazard Tree in transmission ROW" because the picture shows a "hazard tree" rather than a "danger tree" based on CL&P's definitions: A "danger tree" is any tree that could contact a transmission line when it falls. A "hazard tree" is any danger tree that possesses certain characteristics that would result in the tree being classified as a higher risk of failing. Structurally weak species, growth patterns, decay or damage or poor rooting would be characteristics considered when determining if a danger tree is a hazard tree. A hazard tree would also be any tree within the right-of-way that has grown tall enough to encroach within minimum clearance distances to the energized conductors.

Section 6.3.1, P. 6-7, paragraph immediately above Section 6.3.2, last sentence	This sentence should be corrected to explain that "the utilities in the state of Connecticut use herbicides for transmission right-of-way vegetation control, but they do not use growth retardants."
Section 6.3.2, P. 6-7, first paragraph, last sentence	This sentence lists a number of maintenance work activities associated with different components of underground transmission cable systems. Two other examples of underground transmission system equipment components that need to be maintained are sheath bonding equipment in XLPE splice vaults and cable-temperature monitoring systems.
Section 6.5, P. 6-10, first paragraph, fourth sentence	In this sentence, the word "Manage" should be deleted and replaced with "Management" because the sentence describes enhanced vegetation management plans.
Sections 7.4 & 7.5, P. 7-2 & 7-3, bullet list and formulas	This bullet list in Section 7.4 provides and explains the factors that influence the magnitude of the cost of losses and Section 7.5 provides the formulas that were used by KEMA to approximate the cost of transmission losses. CL&P suggests that Section 7.5 also include an explanation that the assumed values for some of the factors are provided at the top of the tables included in Appendix B.
Section 8.1.2, P. 8-3 & 8-4, Tables 8-1, 8-2 & 8-3	Although noted in the text in Sections 8.1.1 and 8.1.3, it would be helpful to explain under each of these tables that a phase current of 1,000 amperes was assumed for the magnetic field calculations. In addition, CL&P presumes that a 5% over-nominal voltage may have been used, but that is not stated in the tables. It would be useful to also note what the assumed voltage was used under each of these tables.
Section 8.1.3, P. 8-4, first paragraph, third sentence	This sentence explains as shown in Table 8.3 that even though the power flow is assumed to be twice as high for the double circuit line compared to the single circuit line, "EMF levels for the double circuit line increase by less than a factor of two." The following sentence explains that this result "is due to some cancellation in the fields from the two circuits." CL&P recommends that the reference to "EMF" (which stands for electric and magnetic fields) be changed to "Magnetic Field" or "MF" because the described cancellation effect applies to magnetic fields, but the effect on electric fields is somewhat different. The reduction in magnetic fields will be more consistent across the ROW, whereas the reduction in electric fields due to reverse phasing will change the shape of the electric field profile and in some locations the electric field may be slightly higher with reverse phasing than without reverse phasing.
Section 8.2.2, P. 8-6, first paragraph, second sentence	This sentence states that a "steel pipe provides the maximum shielding effect on magnetic fields, compared to a flat steel plate." CL&P submits that the reference to a flat steel plate is inappropriate with respect to HPFF cables; while a flat steel plate might be

	considered for use over XLPE cables it would not be considered for HPFF cables. Also, magnetic shielding has not yet been discussed in the Report. CL&P suggests that this sentence be revised to state simply that the pipe provides a shielding effect on the magnetic fields.
Section 8.2.2, P. 8-6, first paragraph, fifth sentence	This sentence refers to magnetic field measurements taken on the 345 kV HPFF section of the Greater Springfield Reliability Project (GSRP). This reference is incorrect because GSRP does not have any HPFF section and this project is not yet in service. This reference should be revised to refer to the Bethel-Norwalk project, which includes CL&P's only 345-kV HPFF underground cable. In addition, the text included in footnote [2] on P. 8-8 is incorrect. This footnote should be revised to reference CL&P Response to Connecticut Siting Council Request for Information for Docket No. LIFE-CYCLE 20111, Connecticut Siting Council Investigation into the Life-cycle Costs of Electric Transmission Lines, Interrogatory Set 2, Q-CSC-019, October 21, 2011. Attachment 1 – "Post Construction Magnetic Field Measurements" and Attachment 2 – "Pipe-Type Cable Magnetic Fields".
Section 9.1, P. 9-1, last paragraph on page	The reference to the "Public Utilities Regulating Authority" is incorrect. This reference should be corrected to the "Public Utilities Regulatory Authority." This same correction should be made on P. 9-3 in Table 9-2.
Section 9.1, P. 9-2, paragraph, second sentence.	This sentence refers to the agencies that provide input into the U.S. Army Corps of Engineers (Corps) permitting process. Native American Tribes should be included as another group providing input to the Corps because they provide key input to the Corps' permitting process.
Section 9.2.1, P. 9-4, second paragraph.	In the first sentence, delete the phrase "Electro-Magnetic Field" and replace it with "Magnetic Field" and change the acronym from "EMF" to "MF" because the referenced higher cost designs were needed to mitigate magnetic fields only. In the second sentence, revise "a new 345 kV transmission line" to "new 345 kV transmission lines." In the third sentence delete the acronym "EMF" and replace it with "MF."
Section 10.2, P. 10-15 & 10-17, Tables 10-3 & 10-4.	In both Tables 10-3 and 10-4, the calculated cost of Losses increases very sharply between 2007 and 2012 (for all categories of transmission lines, i.e., both overhead and underground lines and both 115- and 345-kV lines). The increase in the cost of Losses shown in these tables is greater than 100% for nearly all categories (all except XLPE double circuit lines where the increase is more than 82%), and in some cases the increase in the cost of Losses is more than 500%. If the same cost per kWh were presumed, similar conductor resistances presumed and the same currents presumed for

	these calculations, CL&P does not understand why these sharp increases in the calculated costs of losses would occur. The calculations of costs of Losses should be carefully reviewed to ensure that they are correct and determine why these sharp increases in the cost of Losses occurred.

Respectfully submitted,
THE CONNECTICUT LIGHT AND
POWER COMPANY

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As Agent for CL&P

CERTIFICATE OF SERVICE

I hereby certify that, on this 19th day of April 2012, a copy of the foregoing has been mailed or electronically sent to the persons on the Service List dated November 17, 2011 for this proceeding.

Jeffery D Cochran

Jeffery D. Cochran
Commissioner of the Superior Court