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VIA MESSENGER

January 6, 2006

Pamela B. Katz
Chairman
Connecticut Siting Council
Ten Franklin Square
New Britain, CT 06051

Re: Life-Cycle 2006 - The Connecticut Siting Council Investigation into the Life-Cycle Costs of Electric Transmission Lines

Dear Chairman Katz:

I enclose an original and twenty copies of the Pre-file Testimony of The United Illuminating Company. If you have any questions about this filing, please do not hesitate to contact me.

Very truly yours,

Bruce L. McDermott

cc: Service List

Enclosures

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STATE OF CONNECTICUT

SITING COUNCIL

Re:	The Connecticut Siting Council Investigation into the Life-Cycle Costs of Electric Transmission Lines	)))	Life-Cycle 2006 January 6, 2006

DIRECT TESTIMONY OF THE UNITED ILLUMINATING COMPANY

Executive Summary

Q. Mr. Reed, would you please identify yourself and the other member of the panel from The United Illuminating Company (the "Company" or "UI") who will respond to cross examination?

A. I am Richard J. Reed. My business address is 801 Bridgeport Avenue, Shelton, CT 06484. I am the Vice President of Electric Systems at UI. I joined UI in 1970 and have held various leadership positions in the Company, including Director of Customer Service and my current position, Vice President - Electric System. With me is John Prete who, since October 2002, has been UI's Project Director for the Middletown to Norwalk Project. John is responsible for the schedule, scope and costs of the project for UI and in concert with Northeast Utilities.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to assist the Council and its consultant, KEMA, in revising or updating the Council's "Life-Cycle Cost Studies for Overhead and Underground Transmission Lines," first prepared by ACRES International in March, 1996 (the "1996 Report) and updated by ACRES in 2001 (the "2001 Report") and to identify the issues that the Council should investigate as part of the update. Specifically, this testimony will provide the Council with information that will assist the Council in investigating the comparative life-cycle costs of overhead and underground transmission lines, as required by Conn. Gen. Stats. §§ 16-50r(b) and (c), by discussing new developments in the transmission line field during the last five years. This testimony does not, however, quantify the specific costs associated with the construction of electric transmission lines since the Company believes that the construction costs are directly related to the location of the line.

UI wishes to thank the Council for the opportunity to participate in this five-year review. At the outset, UI notes that the 1996 Report and the 2001 Report were based on 115-kV transmission only. The Company concurs with the Council's recommendation that the 2006 report include 345-kV transmission as well.

Updated Information on First Costs

Q. Are there particular issues you think the Council should focus on as part of its effort to update the 2001 Report?

A. Yes. UI has identified areas in which the cost categories considered in the 2001 Report should be updated. Generally, costs have increased since 2001 for both overhead and underground transmission lines. For example, since the 2001 review of lifecycle costs, there have been significant cost increases for the labor and commodities necessary to construct both overhead and underground transmission lines. The level of cost increases has been exacerbated over the past year as a result of recent natural disasters, which have impacted the rising cost of fuel, high demand for steel and copper, labor, material and manufacturing shortages. These cost increases warrant consideration in this update of the study.

Q. Since 2001, has there been an increase in the costs of permitting a transmission line?

A. In the 1996 Acres study, permitting costs for 115-kV construction were estimated to be $100,000 per project. Permitting costs have increased since 1996 for all projects, and can be expected to increase further as a result of the new role of the Connecticut Energy Advisory Board and requests for proposal in the siting process. The cost of permitting for 345 kV projects is increased further by the costs of complying with the requirements" of Public Act 04-246. While the specific permitting cost will vary by project, the Company looks forward to the opportunity to participate with the Council's consultant in preparing estimates for this component of the lifecycle cost study.

Q. What impact on cost results from construction of an overhead vs. an underground transmission line?

A. Overhead and underground project alternatives will not follow precisely the same route, will have different areas of concern, and must comply with different statutory requirements. All of these factors will affect the actual cost comparison of overhead and underground alternatives for a project, in addition to generic "per mile" lifecycle cost comparisons. For example, the provisions of Public Act 04-246 require a presumption that 345-kV facilities will be constructed underground if adjacent to facilities such as schools, residential areas etc., unless burying the facility is technologically infeasible. This requirement will result in complexity (the need to "porpoise," for example) and cost (in the porpoising example, the need to acquire property and build two transition stations) that is not necessarily reflected in a simple comparison of 5 miles of overhead construction versus a similar underground alternative. The development of lifecycle costs for 345 kV overhead and underground alternatives should include a robust treatment of these costs.

Q. Would you please describe your experience with XLPE cable?

A. The Company will be completing its first installation of XLPE underground cable operating at 345 kV over the next four years. The 345 kV loop in Connecticut will represent the first installation of field spliced 345 kV XLPE underground in the continental United States. In its response to Q-CSC- 4 the Company, in conjunction with CL&P, provided our most recent estimate for this type of construction. Over the next four years, the Company actually will be incurring the installation costs associated with this technology. Areas for consideration in the 2006 update should include the costs associated with Department of Transportation requirements for underground construction on or along state roadways and the costs associated with the handling, testing and disposal of materials excavated from roads. The Company looks forward to working with the Council in leveraging our experience in the Middletown to Norwalk Project in the Council's work on lifecycle costs.

Update on Developments Discussed in 2001 Report

Q. Does the Company have any updated information concerning the topics discussed in the 2001 Report?

A. Yes. There are several technological advances and other developments that were identified in the 2001 Report as potentially affecting costs for overhead or underground transmission construction/maintenance for the period 2001 and beyond which the Council should consider in updating the 2001 Report:

Line Ratings: On page 10 of the 2001 Report, "*recent technological 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*" was discussed. In 2004, the Company implemented the combination of a forced-air cooling system and a dynamic thermal monitoring system on the 1710 and 1730 115 kV underground circuits, which are a critical part of the transmission corridor for transferring power, generated by merchant plants connected to the Pequonnock Substation in Bridgeport, to loads in southwestern Connecticut ("SWCT"). Any reduction in the current-carrying capability of these underground circuits as a result of not implementing the forced air cooling and the dynamic thermal monitoring system on the 1710/1730 circuits would have resulted in considerable reliability risks and additional congestion costs for consumers. In addition, this technological advancement of applying a dynamic thermal monitoring system was at least three times the capital cost savings of the traditional method of increasing the circuit capacity by reconductoring the underwater and underground sections of circuits 1710/1730 with High Pressure Gas Filled ("HPGF") 115- kV cable.

NESC: Page 6 of the 2001 Report lists several updates to the National Electric Safety Code ("NESC") that were being considered at the time. In 2002 an update to the NESC was released that increased the requirements for transmission line construction relevant to wind and ice loading. The Company's construction standards at the time were sufficient to accommodate the additional loading requirements and did not require update. These changes therefore have no impact on the Company's transmission lifecycle costs.

Wood Pole Preservatives: Page 7 of the 2001 Report discussed the possibility that Penta, the most commonly used pole preservative (which UI uses for both transmission and distribution poles) might be banned by the Environmental Protection Agency ("EPA"). The EPA did not ban this substance, and the Company continues to use it.

Transmission Planning Requirements: UI does not expect any ISO-NE planning and operating standards for design and operations of transmission facilities to impact transmission line life cycle costs in the near term.

On August 8, 2005 the Energy Policy Act of 2005 was signed into law. This Act will give the Federal Energy Regulatory Commission ("FERC") new responsibilities in overseeing the reliability of the nation's electric transmission grid. On September 1, 2005, FERC issued a notice of proposed rulemaking on *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval and Enforcement of Reliability Standards*. Under the Act a new national Electric Reliability Organization would be responsible for developing national reliability standards subject to FERC approval. The outcome of this Act may impact transmission lifecycle costs in the future.

Life Expectancy: A transmission line life expectancy of 35 - 40 years was assumed in the 2001 Report. The Company believes that there is no basis to change that assumption. Because 90% of the lifecycle cost occurs in the first 22 years, any cost beyond 35 years contributes very little to the lifecycle cost.

EMF: Methods of calculating electric and magnetic fields are well-established, with well-defined protocols. The Company is aware of no new methods for the calculation of electric and magnetic fields for transmission lines that have developed since 2001.

Q. Are there other changes of which the Council should be aware?

A. Yes. The Council should be aware of the following technological advancements:

HDD: Horizontal Directional Drilling: Although the Company has had experience with directional drilling in distribution applications, the Middletown to Norwalk Project will be UI's first implementation of horizontal directional drilling in a transmission application. The Company will have actual cost information as it proceeds with this technology.

Polymer Insulators: Since 1987, UI has had experience with polymer insulators on a short line. In this application, the polymer insulators have performed well to date. In 2003 a truck fire occurred on I-95 in close proximity to this line. There was a concern that the insulators directly over the fire were damaged, so they were removed from service and a forensic analysis was performed. The analysis revealed that the insulators were in good working order and showed no sign of degradation prior to the fire. However, because porcelain insulators have similar cost and the Company has not had a problem with porcelain insulators, UI does not see a basis for polymer insulators to replace porcelain as the Company's standard.

High Temperature Low Sag Conductors: The Company continues to follow industry developments with high temperature low sag conductors. The Company recognizes this technology as an alternative for capacity upgrades on existing lines where there are lifecycle cost savings to be realized through the elimination of structural upgrades. These lifecycle cost savings would need to be weighed against the uncertainties around the long term reliability of these new conductors and their associated hardware.

High Voltage Direct Current ("HVDC"): The Company continues to recognize HVDC as a viable technology for long distance power transfers, in both overhead and underground applications, if the HVDC proposal meets the system reliability and operational needs cost-effectively.

Q. Does this conclude your testimony?

A. Yes.

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