Report to the Connecticut Siting Council on Loads and Transmission Resources

March 1, 2011

The United Illuminating Company
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Section I. Load Forecast Update

This section presents the results and a summary of the methodology for The United Illuminating Company's ("UI" or "Company") most recent ten-year energy sales forecast (Sales Forecast) and ten-year system peak load forecast (Peak Load Forecast). The Sales Forecast is used for budgeting and financial planning purposes. The Peak Load Forecast is used by the Connecticut Siting Council ("Council" or "CSC") for resource planning purposes in Connecticut. The two forecasts use different forecasting methodologies chosen to fulfill their intended purpose.

Sales Forecast Purpose & Methodology

The primary purpose of the Sales Forecast is to accurately project monthly sales-by-class which is then converted to a revenue forecast using electric service rates by class. The principal output of the Sales Forecast is monthly energy sales. UI utilizes the ten-year Sales Forecast for a number of purposes. A key use of the Sales Forecast is to project the energy sales as the basis for predicting revenue over the next 12 to 24 months. The UI Sales Forecast produces monthly forecasted energy sales weather-adjusted to "normal weather" or average weather conditions.

Weather has a large impact on both sales and peak load. Any analysis of the actual historical sales and peak load must consider the weather conditions under which those sales and peak loads occurred. The Company's sales forecasting process begins by weather-adjusting the actual, customer-class specific, historical sales data to the sales that would have been experienced under normal weather, using heating degree days (HDD) and cooling degree days (CDD) based on a standard of 65 degrees Fahrenheit for the transition from heating-based to cooling-based sales.

The sales forecasting process then moves to the creation of a Base Energy Sales Forecast which reflects the projected sales from UI's existing base of customers. The Base Sales Forecast development employs focused analytical processes that weather-adjusts and evaluates the most recent energy sales history of its customers, trends in the local and state economies and the sales forecast team's interpretations of how these factors are likely to impact UI's future monthly sales.

The impact to sales from Conservation and Load Management (C&LM) and Distributed Generation (DG) currently on the UI system are embedded in the historical data used to develop the Base Energy Sales Forecast, and therefore, the future impact of these resources is accounted for in the Base Energy Sales Forecast results. UI adds to the Base Energy Sales Forecast the projected future annual impact of incremental additions of new C&LM and DG to account for the future additions of these resources.

In addition, UI adds an estimate of sales resulting from specific, new customers projected by UI's Economic Development group. The addition of new customers is another variable that can materially impact sales and peak loads. UI's Economic Development group creates regular projections of new customer additions and deletions to the system based on their interaction with municipalities, Account Managers, potential developers and businesses. These new loads include expansions of existing UI customers, redevelopment of existing areas and new "green field" construction. UI's final Sales Forecast results from the summation of the normal weather-adjusted Base Energy Sales Forecast and new large customer sales along with the decrement to sales due to projected C&LM and DG.

Peak Load Forecast Purpose & Methodology

The purpose of the peak load forecast shown in Exhibit I is to allow the Council to effectively forecast and evaluate the demand and supply balance in Connecticut. The primary output of UI's Peak Load Forecast is the forecast of system peak loads under both normal and extreme weather conditions. Normal weather or average weather, also referred to as a 50/50 forecast, means the data provides a 50% confidence, from a statistical perspective, that forecasted normal weather-adjusted system peak will be exceeded 50% of the time on the peak load day, due to weather conditions. Extreme weather, also referred to as a 90/10 forecast, means the data provides a 90% confidence, from a statistical perspective, that the forecasted extreme weather-adjusted system peak will be exceeded only 10% of the time on the system peak day, due to weather conditions. In other words, the forecasted 90/10 peak load will be reached or exceeded once every ten years.

The UI Peak Load Forecast is a derivative of a quarterly sales forecast and forecasted customer class-level load factors. The forecast of quarterly sales used for the Peak Load Forecast is strictly an interim calculation step that utilizes a different forecasting methodology than the revenue-focused Sales Forecast described above. The Peak Load Forecast is derived from weather-adjusted sales that use an average monthly temperature methodology to weather-adjust the sales. This is different than the method used in the revenue-focused Sales Forecast described in the prior section. For the Peak Load Forecast development, the Company first uses customer-class specific regression models to weather-adjust the historic sales data to equivalent sales that would be seen under normal weather conditions based on 30-years of historical weather data. The normal weather-adjusted sales data is then used to develop a series of econometric models for each major customer class which relates the sales to economic and demographic drivers, obtained from independent sources. The parameters used in the individual econometric models vary by the customer class. The models are then used to produce forecasts of quarterly sales for each major customer class under normal weather conditions.

Next, UI calculates the weather-adjusted historical system peak loads, for both normal weather and extreme weather conditions. The weather-adjustment for historic peak loads is based on a model that relates the twelve-hour average Temperature Humidity Index (a mathematical formula that combines temperature and humidity into a single number) to historical summer weekday peak loads (THI Model). The THI Model is then used to adjust historic peak loads to the loads that would have been seen under normal or average temperature and humidity conditions and for extreme conditions.

The weather-adjusted sales and peak loads in conjunction with load research data are used to calculate historical class-level load factors and forecast class-level load factors for both normal and extreme weather conditions. The forecasted class-level load factors are then used to translate the class-level annual sales into a Base Load Forecast for both normal and extreme weather-adjusted conditions. The Base Load Forecast reflects the forecasted peak load resulting from UI's existing levels of C&LM, DG and existing base of customers. Similar to the Sales Forecast, the Company accounts for projected new C&LM, DG and new or removed large customer loads separately. UI's final Peak Load Forecast results from the summation of the Base Load Forecast and new or removed large customer loads along with the impact due to incremental additions of new C&LM and DG.

Normal Weather-Adjusted Historical and Forecasted Data

The data shown in Exhibit 1 includes actual historical data for system energy requirements, sales and peak load. Exhibit 1 also includes historical and forecasted sales and peak load adjusted to normal weather conditions. UI is a summer peaking utility due primarily to the air conditioning loads on its system. During recent history, between 2000 and 2010, UI has experienced lower normal weather-adjusted sales growth as compared to its normal weather-adjusted peak load growth (i.e., -2.1% sales growth versus a +1.3% peak load growth in the past ten-years). This is attributed to changes in customer behavior regarding energy usage, the unprecedented recession along with an increase in air-conditioning loads. It should be noted that in four of the last ten years of historical data (2001, 2002, 2006 and 2010), the actual peak load has exceeded the normal weather-adjusted peak load. This exceedance is consistent with the design of the normal weather adjustment, in that, typical variations in weather alone will cause the normal weather-adjusted value to be exceeded 50% of the time on the peak load day. This recent history of peak loads reinforces the need for the Company to consider extreme weather in its Peak Load Forecasts. The forecast of the normal weather-adjusted peak load projects a growth of 15.0% between 2010 and 2020. However, the forecast of sales projects only a modest growth of 4.0% during the same period due to the projected small incremental sales increases from the existing customer base and new customers being reduced due to incremental C&LM and DG additions. The Sales Forecast is higher than last year’s forecast due to the impacts of a quicker economic recovery in the short term, and a reduction in the impact of DG and C&LM additions throughout the forecast horizon. The normal weather-Adjusted Peak Load Forecast is lower than last year’s forecast (63 MW lower in year 2019).

Extreme Weather-Adjusted Historical and Forecasted Data

In addition to the normal weather-adjusted data, Exhibit 1 also shows historical and forecasted peak loads adjusted to extreme weather conditions. The 2001 to 2010 historical data in Exhibit 1 shows growth in the extreme weather-adjusted historical Peak Loads as compared to a reduction seen in the historical normal weather-adjusted Peak Loads (i.e., 3.7% growth in extreme weather peak load versus -0.5% growth in the normal weather peak load). The Company's extreme weather-adjusted Peak Load Forecast shows a growth of 18.2% during the period from 2010 to 2020. This forecasted growth is approximately the same as last year's due to the continued impacts of forecasted economic recovery during this period. While the extreme weather-Adjusted Peak Load Forecast percentage growth is slightly higher for this year's forecast than last year's forecast (for the full ten-year period of the respective forecast); the forecasted peak in year 2019 is 41 MW lower than last year's forecast due to the economic impact on the actual 2010 peak load.

The ability to predict when extreme weather will occur or the exact amount of economic activity that will be realized is always problematic. Therefore, prudent planning requires that the possibility of the effects of extreme weather (i.e., high temperatures and high humidity) within the forecast time period be recognized, as well as appropriate assumptions of future economic development activity. Plans must be formulated to meet this possible demand. The bounds of the Company's forecasts from the normal and extreme weather-adjusted scenarios are intended to provide a plausible range of futures. No single forecast will be accurate throughout the forecast period. When extreme weather occurs, regardless of the timing, the system infrastructure must be in place to serve the load safely and reliably[1].

UI Peak Load Scenario for ISO-NE Regional Transmission Planning

The Company has also developed a forecast of peak loads that is comparable to the assumptions used in the development of the Independent System Operator-New England ("ISO-NE") Capacity, Energy, Loads and Transmission ("CELT") peak load forecast and is provided for informational purposes in Exhibit 2. This Peak Load Scenario excludes all C&LM, DG and potential new large customer loads in order to be consistent with the ISO-NE treatment of loads and resources in their regional planning.

[1] The purpose of the peak load forecast shown in Exhibit I is to allow the Council to effectively forecast and evaluate the demand and supply balance in Connecticut.

Distributed Generation

The Connecticut General Assembly passed a landmark legislative initiative in 2005: Public Act 05-01, June Special Session, *An Act Concerning Energy Independence* ("PA 05-01"). The implementation of the Act, carried out by the DPUC, provides monetary grants to offset the capital cost of installing DG. Although the grants are no longer being provided by the DPUC, approved grants totaling 18.9 Megawatts[2] of capacity are awaiting a customer decision. There exists some uncertainty regarding the ultimate outcome of these projects. Even with the grants made available, each customer must decide for themselves, within the 3 year timeframe allotted, whether the installation is economically attractive. This introduces uncertainty into forecasting the installation of any remaining units. In addition to the capital grants, the program also provides for waiver of certain demand charges as well as waiver of gas distribution charges. The program has so far successfully added about 25.6 Megawatts of DG capacity in the UI service territory.

In development of the sales forecast shown in Exhibit 1, those projects no longer anticipated have been excluded from the sales forecast and an 85% capacity factor was utilized for forecasted units. The incremental impact of DG to the sales forecast is shown in Table 1.

[2] Operational DG output is based on capacity listed on grant application and not the actual generator output.

Table 1 – Incremental Annual Impact of DG to Sales Forecast

Year	Reduction in Energy Sales due to DG (GWhrs)
2011	107
2012	49
2013	20
2014	-
2015	-
2016	-
2017	-
2018	-
2019	-
2020	-

In development of the peak load forecasts presented in Exhibit 1, all of the operational units have been included as offsets to load (utilizing actual generator output). Regarding forecasted units, only one project is expected to enter service in the 12 months between October 1, 2010 and September 30, 2011. Only 50% of the units that have received grant approval with a 2011 - 2012 planned date of operation have been included as offsets to load. Table 2 presents the incremental impact to system peak due to DG.

Table 2 – Incremental Annual Impact of DG to Peak Load Forecast

Year	Reduction in System Peak Load Forecast due to DG (MW[3])
2011	5.4
2012	4.1
2013	-
2014	-
2015	-
2016	-
2017	-
2018	-
2019	-
2020	-

[3] Values are based on 50% of the projects that have received DPUC grant approval and represent estimated customer metered values. For UI's system load, these reductions were 'grossed-up' using the system loss factor.

The DPUC has evaluated this DG grant program for cost effectiveness to the ratepayers and, as a result of this evaluation, has ended the program. The change to the monetary grant program took effect for all projects that submitted applications on or after October 14, 2008.

Conservation & Load Management

The C&LM Programs for 2011 have bloomed into a comprehensive suite of cost-effective measures. Some of the largest program budgets have been made available through resources additional to the existing 3 mill charge. These additional sources of program dollars include the Regional Greenhouse Gas Initiative (RGGI), the ISO-NE Forward Capacity Market (FCM), the Connecticut Class III renewable program, and for a limited time the American Recovery and Reinvestment Act (ARRA). Although pending reductions in funding resources for future years threatens the size of the program, UI is committed to improving program focus and effectiveness to maximize the benefits our customers receive from every dollar spent. UI is increasing customer satisfaction by enhancing the comprehensiveness of the programs and implementing continuous positive engagement with customers and vendors.

In May 2010, the CT Legislature took legislative actions through the adoption of Public Act 10-179 to divert approximately $21 million from the C&LM fund in 2012 and $28 million annually from 2013 through 2018 to pay off bonds to help reduce the State's budget deficit. Approximately one-third of the EDCs annual C&LM fund will be impacted. In order to avoid any impact on American Recovery and Reinvestment Act (ARRA) funding, the redirection of the C&LM funds will not begin until April 2012. While this action will not impact the 2011 budget, future budgets for electric programs beginning in 2012 will decrease.

PA 07-242, *An Act Concerning Electricity and Energy Efficiency* ("2007 Act") required the Companies to begin an integrated resource planning ("IRP") process. On January 1, 2010, the Companies submitted their third IRP plan to the CEAB. The 2010 IRP has two additional resource strategies for Demand Side Management (DSM) that are above and beyond the reference level DSM (business as usual) strategy. The targeted DSM strategy is comprised of specific initiatives that will achieve zero load growth in Connecticut in five years and a slight reduction thereafter. The All Achievable Cost-Effective DSM strategy reflects a major expansion of current programs and was constructed based on a draft Connecticut energy efficiency potential study completed in 2009 by the Energy Conservation Management Board ("ECMB")[4]. The companies proposed both strategies for additional energy efficiency as part of the IRP plan submitted to the Connecticut Energy Advisory Board (CEAB) on January 1, 2010. As a result of the DPUC review of the plan under Docket 10-02-07, the DPUC did not endorse increasing ratepayer funding to pursue either strategy. As a result, UI is focusing on increasing cost-effectiveness under the current DSM strategy to improve the benefit both to the electric system and to ratepayers.

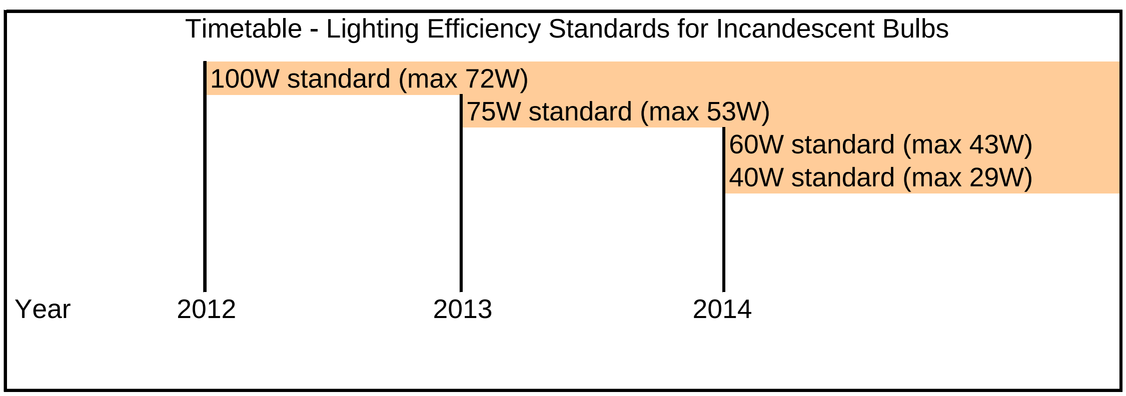
Among other additional funding sources, The American Recovery and Reinvestment Act of 2009 ("Stimulus Act") has recently provided Connecticut with a significant boost of resources for energy efficiency. In 2009 UI received $2.3 million from the Stimulus Act and allocated it towards the Homes Energy Solutions, Energy Opportunities and Small Business programs. Connecticut received an additional $3.4 million for an appliance rebate program. These funds are nearly exhausted, and there is no additional funding from ARRA included as part of the current load forecast.

Funds from the Regional Greenhouse Gas Initiative ("RGGI") and Class III Renewable Energy Credits ("RECs") remain to augment the three mill Public Benefits Charge on customers' electric bills. RGGI is the first mandatory, market-based effort in the United State to reduce greenhouse gas emissions. The participating RGGI states cap allowable CO_2 emissions, sell emissions allowances through auctions, and use the auction proceeds to fund energy efficiency, renewable energy, and other clean energy programs and technologies.

Legislation has effected substantial change to the lighting portion of C&LM programs. Beginning in 2012, pursuant to the Energy Independence and Security Act of 2007, nationwide

[4] In 2010 the ECMB changed its name to the Energy Efficiency Board ("EEB").

lighting efficiency standards (Lighting Efficiency Standards) will be implemented. The purpose of the Lighting Efficiency Standards is to introduce minimum energy performance standards for incandescent bulbs that will, over a period of time, remove inefficient lighting products from the marketplace. Incandescent bulbs will still be available in 2012 and beyond if they meet the Lighting Efficiency Standards guidelines. The timetable for compliance is included in the graphic following. The standard may result in declining lifetime total savings for Compact Fluorescent Light bulbs ("CFLs") based on date of sale or installation. As lighting makes up a significant portion of the program offerings and savings in every sector, particularly concerning CFLs in the residential programs, UI will need to carefully monitor the development of lighting products that meet the new standard to determine what savings may be achieved from the installation of CFLs. In addition to determining the role of CFLs as an energy saving technology, UI will continue to investigate non-CFL technologies that achieve savings beyond the standard such as LED or induction lighting.



In 2010, the transition period for the Forward Capacity Market ("FCM") ended, and the permanent FCM was put in place beginning June 1, 2010 by the ISO-NE. As New England's energy markets continue to develop and evolve, the Company continues to be an active participant in the development of the ISO-NE stakeholder process to refine the markets. The FCM allows market participants to bid their peak demand savings into the capacity market.

Market participants earn capacity payments for qualifying resources, such as distributed generation, energy efficiency, load management or load response. This was the first time in the United States that reduction in demand through energy efficiency and demand response programs was considered as electrical capacity equivalent to supply-side generation sources. Additional electrical capacity "produced" through the implementation of efficiency and load management measures becomes a resource, which can then be bid to ISO-NE on a level playing field with new generation. UI has entered peak demand savings from energy efficiency and load management projects into the transition period FCM on behalf of the Connecticut Energy Efficiency Fund and has successfully bid capacity in the first four capacity auctions. In addition, UI is an active demand response provider with 64 MWs of capacity currently enrolled.

The strategic focus of UI's programs is the result of a multi-level collaborative process involving UI and a diverse group of stakeholders. These stakeholders include: the Department of Public Utility Control, the EEB, Connecticut state government, consumer and business interests, national and regional environmental and energy efficiency organizations, design professionals and energy services providers.

UI participates in national and regional activities to develop a long-range focus for energy efficiency. UI partners with the Consortium for Energy Efficiency ("CEE"), the American Council for an Energy-Efficient Economy ("ACEEE"), Northeast Energy Efficiency Partnerships ("NEEP") and other utility and public benefit fund organizations. Together with these partners, UI is involved in regional or programmatic evaluations, market baseline research, development of efficiency standards, exchange of programmatic ideas and concepts and the assessment of the need for incentives. These efforts have produced many of the energy efficiency concepts and measures upon which the programs are based.

Table 3 illustrates the incremental impact of C&LM programs to the sales forecast.

Table 3 – Incremental Annual Impact of C&LM to Sales Forecast

Year	Reduction in Energy Sales due to C&LM (GWhrs)
2011	63
2012	41
2013	33
2014	29
2015	30
2016	30
2017	30
2018	30
2019	31
2010	31

Table 4 shows the incremental annual impact of C&LM to the peak load forecast.

Table 4 – Incremental Annual Impact of C&LM to Peak Load Forecast

Year	Reduction in System Peak Load Forecast due to C&LM (MW[5])
2011	7.3
2012	4.9
2013	4.1
2014	3.8
2015	3.8
2016	3.9
2017	3.9
2018	3.9
2019	3.9
2020	4.0

[5] Values represent estimated customer metered values. For UI's system load these reductions were 'grossed-up' using the system loss factor.

Section II. Transmission Planning

The combination of the development of the competitive wholesale generation marketplace and the capacity requirement to accommodate increasing levels of forecasted peak demands has impacted transmission system utilization. The UI projects included in this filing are a result of the impact of these factors on the existing infrastructure. These projects will enable the Company to fulfill its obligation to provide reliable service to its customers and to meet the reliability standards mandated by national and regional authorities responsible for the reliability of the transmission system: the North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council (NPCC) and ISO-NE.

Recent regulatory developments regarding renewable electric generation and emissions may provide impetus for additional transmission projects in the future. Connecticut, like other New England states, has established a substantial renewable portfolio standard (RPS) that ramps up over time to approximately 14% of energy in 2011 to 30% of energy in 2020 for all Classes of renewables. New England's requirements for generation from renewable resources are projected by ISO-NE to be ramping up from approximately 18,000 GWh in 2010 to approximately 44,000 GWh in 2020.[6]

For Connecticut, and likely other southern New England states, it appears it will be difficult to satisfy the RPS exclusively with domestic (in-state) assets. There may be significant renewable potential in northern New England states, for example Maine, New Hampshire, and Vermont. In addition, substantial potential exists in adjoining regions, including the Canadian provinces. In a recent preliminary assessment, ISO-NE indicated that the eastern Canadian provinces have potential in excess of 13,000 MW of renewable resource capacity.[7]

[6] ISO-NE Regional System Plan Update, October 2010.
[7] ibid

It appears that the majority of renewable potential is remote from load in New England. To the extent the renewable needs cannot be satisfied locally or through alternative compliance payments, additional transmission projects may be necessary to tap remote renewable-rich regions and facilitate import of remote renewable generation. In September of 2009, the New England Governors published an "Energy Blueprint." To inform the New England Governors, and other policy makers, New England States Committee on Electricity ("NESCOE") requested that ISO-NE conduct a Renewable Development Scenario Analysis (RDSA) which subsequently established that:

> *"A number of potential transmission projects can be identified that would allow for the reliable transfer of power from off-shore and on-shore wind resource regions to load across New England, and for export to our neighbors. The length of such transmission is modest on a national scale given the region's relatively small geographic footprint. The cost associated with such transmission varies significantly depending on the level of overall resource development: a lower level of investment would result in renewable resources sufficient to meet our renewable energy goals while more aggressive investment could enable New England to export renewable power to neighboring regions."*[8]

On December 30, 2010, NESCOE issued a Request for Information (RFI). According to NESCOE, this process will inform and influence future regional steps in the potential coordinated procurement of renewable energy resources to help New England's renewable energy and environmental goals in the most cost-effective manner. The focus of this RFI effort is on new renewable energy projects whose output would qualify as Renewable Portfolio Standard-

[8] New England Governors' Renewable Energy Blueprint, September 15, 2009, page 15, item 6.

eligible in five New England states (CT, MA, ME, NH and RI) and for Vermont's renewable energy goals and that could be placed into commercial operation by the end of 2016.

NESCOE developed the RFI to minimize the amount of "core response information" required from respondents regarding new renewable energy resources, while including the opportunity for respondents to provide any supplementary information that may be useful to NESCOE. The RFI process also allows transmission owners and developers to provide "transmission only" information regarding potential transmission projects that could facilitate the delivery of energy from specific or generic renewable energy resources to New England loads. UI may respond (either alone, or together with other regional Transmission Owners) to provide "transmission only" information, and recently posted some information regarding this intention on its OASIS web site. The short "Core Information Spreadsheet" for renewable generation resources was due on 2/4/11; and the "Supplemental Information Form" for additional information (including transmission only information) was due on 2/25/11.

UI's planned transmission system modifications are listed in Exhibit 3 and are outlined below.

To address reliability, substation capacity and voltage support issues in the UI service territory, UI has received approval of Declaratory Rulings from the Council that no Certificates of Environmental Compatibility and Public Need are required for the following projects:

- Broadway 115/13.8-kV Substation Expansion Project
- East Shore 115-kV Capacitor Bank Transient Recovery Voltage (TRV) Project
- Union Avenue – Metro North 115/26.4-kV Substation Project
- Grand Avenue 115-kV Switching Station Modernization Project
- Devon Tie 115-kV Switching Station Bulk Power System (BPS) Compliance Project

The Broadway 115/13.8-kV Substation Expansion Project was completed in December 2010 while the East Shore 115 kV Capacitor Bank TRV and the Union Avenue – Metro North 115/26.4-kV Substation Project are expected to be completed by March 2011 and March 2012 respectively.

In 2009 the Council also approved a Declaratory Ruling regarding UI's proposed Grand Avenue 115-kV Switching Station Modernization Project, which addresses reliability compliance issues in the greater New Haven area. The Grand Avenue 115-kV Switching Station Modernization Project is expected to be in service by May 2012. In 2010, UI received a Declaratory Ruling from the Council regarding UI's Devon Tie 115-kV Switching Station BPS Compliance Project, which addresses reliability compliance issues in the greater Milford area. The Devon Tie 115-kV Switching Station BPS Compliance Project is expected to be in service by December 2011.

UI has other transmission infrastructure upgrades under internal review, such as the East Shore Substation Capacity Upgrade Project, an upgrade to the existing 115/13.8-kV East Shore Substation needed to address capacity and voltage related concerns in the greater New Haven area. UI anticipates making a filing with the Council for this project in 2011 which is projected to be in service in 2013. The East Shore Substation Capacity Upgrade Project would result in the deferral, outside of the ten year horizon, of the North Branford Substation Project which was described in UI's March 1, 2010 filing of the, "Report to the Connecticut Siting Council on Loads and Transmission Resources."

The Shelton Substation Project, a new 115/13.8-kV substation, needed to address distribution reliability and capacity issues related to substation thermal overloads and voltage collapse concerns in the greater Shelton area. UI anticipates making a filing with the Council for this project in 2012, which is projected to be in service in 2015.

The Fairfield Substation Project is a new 115/13.8-kV substation needed to address distribution reliability and capacity issues related to substation thermal overloads in the greater Fairfield area. UI anticipates a 2017 filing with the Council for this project which is projected to be in service in 2020.

UI along with ISO New England (ISO-NE) and Northeast Utilities (NU) are nearly complete with a long term (2018) reliability Needs Assessment of the Southwest Connecticut (SWCT) area. The ISO-NE Planning Advisory Committee has been updated several times in 2010 regarding the findings associated with this SWCT Needs Assessment. This assessment's objective is to evaluate the reliability performance of SWCT in meeting NERC, NPCC, ISO-NE, NU and UI standards and criteria. The study was conducted in accordance with the regional planning process as outlined in Attachment K of the ISO-NE Open Access Transmission Tariff (OATT). This study identified reliability transmission needs in UI's service territory related to capacity limitations, unacceptable voltage performance and high short circuit current levels. It is expected that ISO-NE will release a SWCT Needs Assessment report early in 2011.

In 2011, a second study, the SWCT Area Transmission Solution Study, will be conducted to develop and analyze transmission solutions to address the needs identified in the SWCT Needs Assessment. UI expects to make additional filings to CSC in 2012 to address the capacity limitations, unacceptable voltage performance and high short circuit current level needs in UI's service territory; i.e., in the Naugatuck Valley, greater Bridgeport and New Haven areas.

Prior projects contemplated by UI, namely the Naugatuck Valley 115-kV Reliability Improvement Project and the Pequonnock 115-kV Fault Duty Mitigation Project, remain listed in

Exhibit 3 “Transmission System Planned Modifications” and will be updated in subsequent filings based on the results of the ISO-NE SWCT Area Transmission Solution Study.

Please note that Exhibit 3 to this Report includes only those planned transmission projects that UI is responsible to undertake. It does not include any plans or proposed actions by third parties that would require transmission system modifications in UI’s service territory. It would be the responsibility of such third parties to provide the CSC with a report of their plans as appropriate. Any such proposed modifications would require notification and coordination with UI so the Company can assess the impacts on its transmission system and ensure the system’s continued reliability.

Section III EXHIBITS

EXHIBIT 1 System Energy Requirements, Annual Sales, and Peak Load Table

The United Illuminating Company

System Energy Requirements, Annual Sales, and Peak Load

History

								Normal Weather Adjustment					**Extreme Weather Adjustment**		
Year	Total Sys. Req. (GWh)	Annual Change (Pct.)	Actual Sales (GWh)	Annual Change (Pct.)	Actual System Peak (MW)	Annual Change	Load Factor (Pct.)	Weather Adjusted Sales (GWh)	Annual Change (Pct.)	Weather Adjusted System Peak (MW)	Annual Change	Load Factor (Pct.)	Weather Adjusted System Peak (MW)	Annual Change	Load Factor (Pct.)
2000	5,977	-	5,654	-	1,157	-	59%	5,708	-	1,236	-	-	1,292	-	-
2001	6,010	0.6%	5,724	1.2%	1,324	14.4%	52%	5,689	-0.3%	1,259	1.8%	55%	1,322	2.3%	52%
2002	6,051	0.7%	5,781	1.0%	1,310	-1.1%	53%	5,684	-0.1%	1,259	0.0%	55%	1,318	-0.2%	52%
2003	6,071	0.3%	5,763	-0.3%	1,281	-2.2%	54%	5,716	0.6%	1,285	2.0%	54%	1,351	2.5%	51%
2004	6,205	2.2%	5,952	3.3%	1,201	-6.3%	59%	5,952	4.1%	1,300	1.2%	54%	1,364	0.9%	52%
2005	6,360	2.5%	6,106	2.6%	1,346	12.1%	54%	5,995	0.7%	1,353	4.0%	54%	1,428	4.7%	51%
2006	6,149	-3.3%	5,919	-3.1%	1,456	8.2%	48%	5,979	-0.3%	1,377	1.8%	51%	1,456	2.0%	48%
2007	6,119	-0.5%	5,917	0.0%	1,298	-10.9%	54%	5,929	-0.8%	1,389	0.8%	50%	1,464	0.6%	48%
2008	5,912	-3.4%	5,729	-3.2%	1,301	0.3%	52%	5,709	-3.7%	1,379	-0.7%	49%	1,467	0.2%	46%
2009	5,673	-4.0%	5,493	-4.1%	1,253	-3.7%	52%	5,593	-2.0%	1,280	-7.2%	51%	1,395	-4.9%	46%
2010	5,950	4.9%	5,735	4.4%	1,365	8.9%	50%	5,587	-0.1%	1,252	-2.2%	54%	1,370	-1.8%	50%
2000 - 2010 growth		-0.5%		1.4%		17.9%			-2.1%		1.3%			6.0%	
2001 - 2010 growth		-1.0%		0.2%		3.1%			-1.8%		-0.5%			3.7%	

Forecast

			Normal Weather Scenario					**Extreme Weather Scenario**		
Year	Total Sys. Req. (GWh)	Annual Change (Pct.)	Weather Adjusted Sales (GWh)	Annual Change (Pct.)	System Peak (MW)	Annual Change	Load Factor (Pct.)	System Peak (MW)	Annual Change	Load Factor (Pct.)
2011	5,769	-3.0%	5,489	-1.8%	1,307	4.4%	50%	1,404	2.5%	47%
2012	5,779	0.2%	5,498	0.2%	1,368	4.7%	48%	1,476	5.1%	45%
2013	5,785	0.1%	5,505	0.1%	1,411	3.1%	47%	1,529	3.6%	43%
2014	5,830	0.8%	5,547	0.8%	1,423	0.9%	47%	1,549	1.3%	43%
2015	5,875	0.8%	5,590	0.8%	1,423	0.0%	47%	1,558	0.6%	43%
2016	5,938	1.1%	5,650	1.1%	1,425	0.1%	48%	1,568	0.6%	43%
2017	5,967	0.5%	5,678	0.5%	1,430	0.4%	48%	1,582	0.9%	43%
2018	6,014	0.8%	5,722	0.8%	1,434	0.3%	48%	1,595	0.8%	43%
2019	6,060	0.8%	5,766	0.8%	1,438	0.3%	48%	1,608	0.8%	43%
2020	6,107	0.8%	5,810	0.8%	1,440	0.1%	48%	1,619	0.7%	43%
2010 - 2020 growth		2.6%		4.0%		15.0%			18.2%	

1. System Requirements are sales plus losses and Company use.
2. Load Factor = System Requirements (MWh) / (8760 Hours X System Peak (MW)).
3. All forecasts include C&LM, DG & potential new large customer planned loads identified by UI Economic Development.

EXHIBIT 2 Peak Load Scenario for ISO-NE Regional Planning Process

The United Illuminating Company

Peak Load Scenario Comparable to ISO-NE's CELT Forecast Assumptions (Final forecasts to be provided to ISO-NE)

Forecast

	Normal Weather Scenario			Extreme Weather Scenario		
Year	System Peak (MW)	Annual Change		System Peak (MW)	Annual Change	
2011	1,316	5.1%		1,413	3.1%	
2012	1,357	3.1%		1,464	3.6%	
2013	1,396	2.9%		1,513	3.3%	
2014	1,410	1.0%		1,537	1.6%	
2015	1,414	0.3%		1,548	0.7%	
2016	1,420	0.4%		1,563	1.0%	
2017	1,428	0.6%		1,580	1.1%	
2018	1,436	0.6%		1,597	1.1%	
2019	1,444	0.6%		1,614	1.1%	
2020	1,450	0.4%		1,630	1.0%	
2010 - 2020 growth			15.8%			16.8%

1. All forecasts <u>exclude</u> C&LM, DG & potential new large customer planned loads identified by UI's Economic Development Department, consistent with ISO-NE CELT load forecasting methodology.

EXHIBIT 3   Transmission System Planned Modifications

Report to the Connecticut Siting Council

List of Planned Transmission Projects for which Certificate Applications are being contemplated, may be subject to Declaratory Ruling, or have already been filed

Projects for which Certificate Applications are being Contemplated	kV	Date of Completion
1. East Shore 115/13.8-kV Substation Capacity Upgrade	115	2013
2. Naugatuck Valley 115-kV Reliability Improvement Project	115	2014
3. Pequonnock 115-kV Fault Duty Mitigation Project	115	2015
4. Installation of new 115/13.8-kV substation in Shelton	115	2015
5. Installation of new 115/13.8-kV substation in Fairfield	115	2020

Projects which have Received CSC Declaratory Ruling Approval		
1. East Shore 115-kV Capacitor Bank Transient Recovery Voltage Project	115	2011
2. Devon Tie 115-kV Switching Station BPS Compliance Project	115	2011
3. Union Avenue Metro North 115/26.4-kV Substation Project	115	2012
4. Grand Avenue 115-kV Switching Station Modernization Project	115	2012