Demographic Considerations

The Trumbull area is one of the "early" suburbs of Bridgeport and experienced its largest population growth from the 1950 – 1970 time frame as shown in the following figure. During the 1990s the Trumbull area grew again as a result of "infill building" and recycling of older neighborhoods. From 1997 to 2001, Trumbull experienced about 100 new homes per year while the greater Bridgeport area experienced about 400 new homes per year. Historically, 100 new homes add about - 1 MVA of peak load. A certain percentage of the new homes, particularly in the older suburbs could actually be redevelopment of existing homes and therefore would have less of an impact on the peak load.

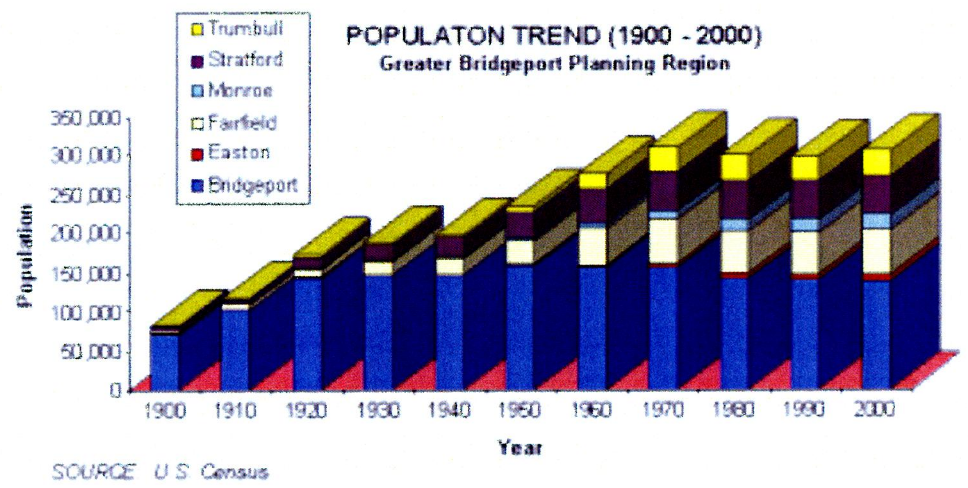

Figure 21 - Bridgeport Population Trend 1900-2000

Load Growth Estimate - Summary

The weather-normalized linear trend lines from Figure 18 and Figure 19 provide the following average peak load growth rates (MVA/year) for both substations:

Table 3 - Historical and Projected Growth Rates (MVA/year)

Substation	Weather Normalized Historical Growth Rate (MVA/ year, 2000 – 2004)	Projected Growth Rate (MVA/ year, 2004 – 2008)
Old Town	0.63	1.0
Trap Falls	0.83	0.65

In conclusion it appears reasonable to consider the UI peak load projections represented by the blue dashed projected lines on Figure 18 and Figure 19 to be a good estimate of the maximum expected values for the years 2004 through 2008, although the Old Town estimate might be slightly low for the next 5 years. The UI projection for Old Town has a higher slope, but the weather-normalized historical load is approximately 3 MW higher initially.

Also, the high vacancy rates, particularly in the Old Town area, might result in sudden load increases that are not accounted for in these projections. Appendix C contains a partial listing of the loads that could materialize up through 2009. It seems prudent to add 5 - 10% to the maximum expected level. When interpreting the results this 5 - 10% adder will be incorporated.

Evaluating Options

The options will be evaluated based on economics and system performance (capacity, availability and quality).

Option Elimination – First Cut due to System Constraints

Do Nothing Option (Shed load if transformer failure occurs)
This option relies on the fact that failures of 115 kV to 13.8 kV substation transformers are extremely rare events as evidenced by the fact that UI has only experienced two such events. One UI transformer failure occurred within one year of transformer installation and was probably due to a manufacturing defect. The other failure occurred at Ash Creek and was due to water intrusion at the handhole access port on the top of the transformer. It is worth noting however that the actual probability of transformer failure may be greater than the perceived failure rate because the Old Town and Trap Falls transformers are about 35 years old.

Accepting the risk associated with do nothing is not advisable in this situation for the following reasons:

1. UI is required to maintain the July 1998 SAIDI and SAIFI levels.
2. UI has recently violated the SAIDI requirements by a significant margin and the consequences of a transformer failure with a do nothing approach could add nearly 2 minutes to SAIDI.

For the above reasons, the "Do Nothing" option has been eliminated.

Transfer Load From Old Town and Trap Falls to other Substations
Reference 2 estimates that the cost for transferring load such that the new substation could be delayed for seven to ten years is approximately $5.5M. For a seven to ten year deferral the Net Present Value (NPV) of this option is greater by $2-3M than the cost of investing in the new substation in 2007.

In addition, the transfer load option results in longer feeders, which increases losses, degrades voltage performance, adds circuit exposure, while failing to provide the potential to improve SAIDI by the same magnitude that can be achieved with the new substation. For these reasons, the "Transfer Load" option has been eliminated.

Install 40 MVA PDS Modular Substation
Reference 2 evaluated the installation of a single 40 MVA Power Delivery System (PDS) at the proposed Trumbull substation site at an estimated cost of approximately $3M. In addition, distribution automation would be required on the four 13.8 kV feeders to be transferred from Old Town and Trap Falls Substations to the 40 MVA PDS at the Trumbull substation site. The cost of this required distribution automation is approximately $600,000.

This option requires some form of distribution automation in order to approximate the inherent backup performance capability of a traditionally designed UI substation. Implementing distribution automation is a "major change" for operating personnel and should not be done without significant pre-planning and the appropriate training programs. In summary, this option is not in accordance with UI's existing operation philosophy and UI lacks the necessary system infrastructure to support this option. It is not prudent to undertake this major initiative to enhance system integrity without having prior operational experience in distribution automation.

Build Substation At Alternate Site

Reference 10 evaluated nine different sites in detail for the new substation. The high cost of building 115 kV tap transmission lines ($3M – $4M per mile) eliminated all sites with the potential to be superior to the selected site. The nine sites that were evaluated in detail in Reference 10 were all located south of Merritt Parkway even though the majority of the load and expected growth is centered about 3 miles north of the Parkway (Figures 2 & 3). The high cost of 115 kV tap lines eliminates this option.

Replace Transformers at Old Town and Trap Falls with Larger Units

Reference 13 quantified the economics associated with replacing the transformers at Old Town and Trap Falls with new 42/56/70 MVA transformers. The cost reported in Reference 13 totaled $6.8M but did not include the cost of upgrading the distribution delivery system, which was subsequently estimated to be $1.5M bringing the total cost to approximately $8.3M. The cost to upgrade the transformers is comparable to, or slightly greater than, the cost of building the new Trumbull substation ($13.4 Million) after the savings associated with the reduction in transmission line charges ($220K/year) are credited to Trumbull substation option. The high cost of uprating the transformers eliminates the practicality of this option since the new substation would provide additional enhancements to both the availability and power quality that would not be obtained by simply uprating the transformers at Old Town and Trap Falls. Additionally, larger transformers in UI substation designs would lead to serious operating issues due to voltage and equipment rating considerations that prevent their use.

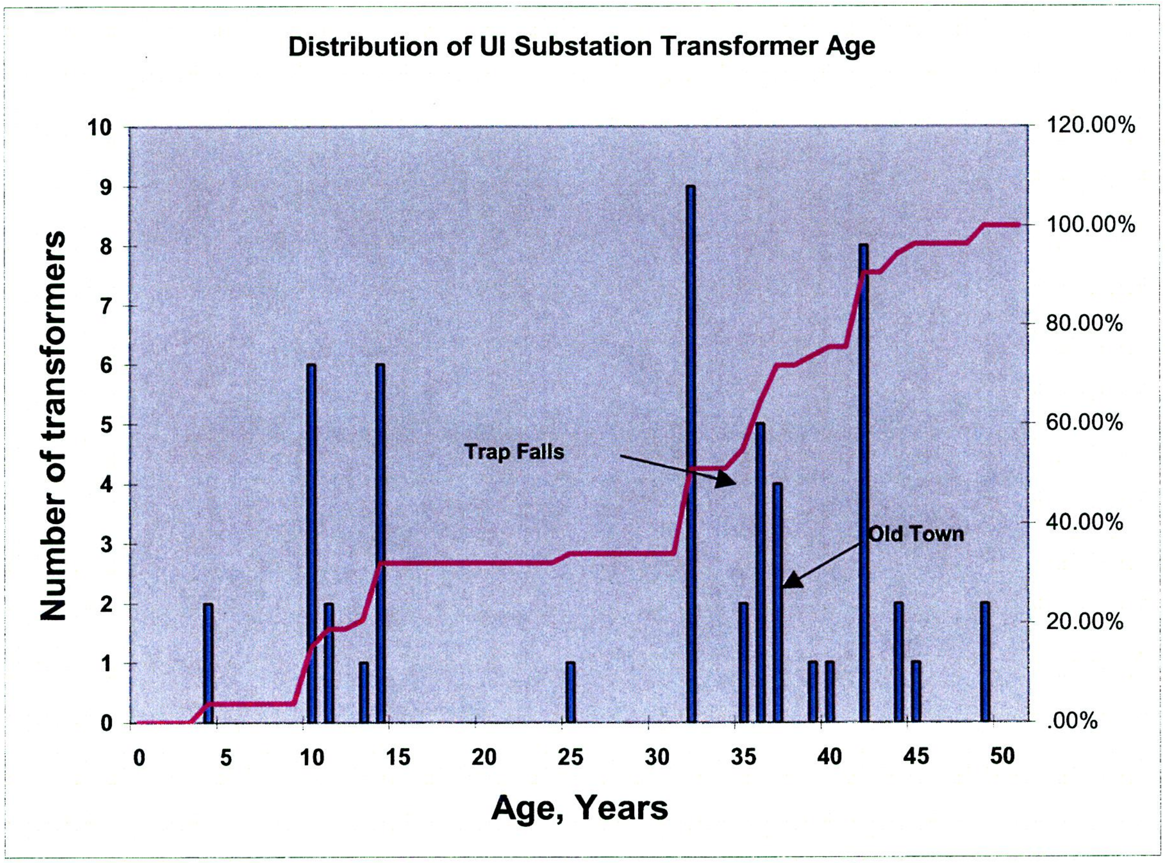

Figure 22 - Major Substation Transformer Age Profile

The age of the existing transformers at Old Town and Trap Falls, relative to the rest of the UI substation transformers, is shown in Figure 22. The Old Town and Trap Falls transformers are over 35 years old, which is approaching the 40 year design life. Half of the UI transformers are 35 years old, or older. It is however generally accepted that the "true age" of a transformer is more influenced by its thermal history then by its chronological age. The historical UI substation design philosophy has resulted in relatively light loads (25%-75% of max rating) on the individual transformers as can be seen by comparing the transformer ratings in Table 2 with the substation loading plots provided in this report. It is reasonable to assume that these transformers could last for more than the 40 year design life. However, EPRI Solutions does not recommend exceeding 50 years, a recommendation that is consistent with the practice of many other utilities. None of the 115 kV to 13.8 kV substation transformers are older than this, although two will reach this age next year. Therefore, assuming that there have been no loading anomalies in the histories of the transformers at Trap Falls and Old Town, approximately 10 years of life remains before their replacement would be recommended. A more accurate estimate of the remaining life of the transformers can be obtained by performing a furfural analysis of the oil and reviewing a detailed loading history along with any significant thermal events.

<u>Feeder Enhancement / Distribution Automation</u>
Feeder enhancement refers to combinations of distribution automation, feeder length reduction and feeder reliability improvement programs. The fundamental problem with this as a stand-alone option is that it does not add any transformer capacity. Because additional transformer capacity is critical to avoiding the potential need for load shedding this option will be eliminated as a "stand-alone" option but will be discussed later in the "Complementary combinations" section.

<u>Distributed Generation (DG)</u>
DG could potentially be utilized to displace substation loading in some applications. Several technical issues preclude the use of a DG solution in this specific application:

1. Existing short circuit levels at UI substations are high and the available fault interrupting capabilities of UI substation equipment is at or near their limits.
2. The addition of any sizable DG would contribute additional fault current which could cause equipment, such as circuit breakers and structural bracing, to be overdutied, possibly causing catastrophic damage to the equipment and risking employee safety.
3. Although DG may improve local capacity, it does not improve the reliability of the distribution system, as the same overall exposure would exist on the distribution circuit.

In order to interconnect significant amount of DG in this area a new substation must be built first.

<u>Conservation and Load Management (C&LM)</u>
UI has offered conservation and load management programs to its customers for over a decade. The cumulative effects of the programs are reflected in the load data that is used in developing the base case for the load forecast. The forecasted C&LM activity is included in identified customer load increases, system sales growth projections and Economic Development Major Project Forecast. UI has long been a proponent of the benefits of C&LM activities and has developed a full complement of C&LM programs as part of Connecticut's restructured electric markets. These programs have delivered load reductions from Commercial and Industrial customers served by these two substations alone. These are reflected in the historic substation loading levels, and C&LM programs will not defer the need for a new substation any longer.

<u>Complementary combinations</u>
The two concepts that complement each other in this situation are "Feeder Enhancement" and "Additional Transformer Capacity". The main potential leverage in this area requires the acceptance of distribution automation. UI is not currently prepared to fully exploit the benefits of distribution automation so options like "Install 40MVA PDS" have been eliminated at this time. The final solution "Building Trumbull Substation" will however incorporate the "feeder length reduction" concept once the substation has been fully expanded.

Evaluation of Preferred Option

<u>Building the Trumbull Substation</u>

The impact that building the Trumbull substation has on the loading at Trap Falls and at Old Town is depicted in the following two figures:

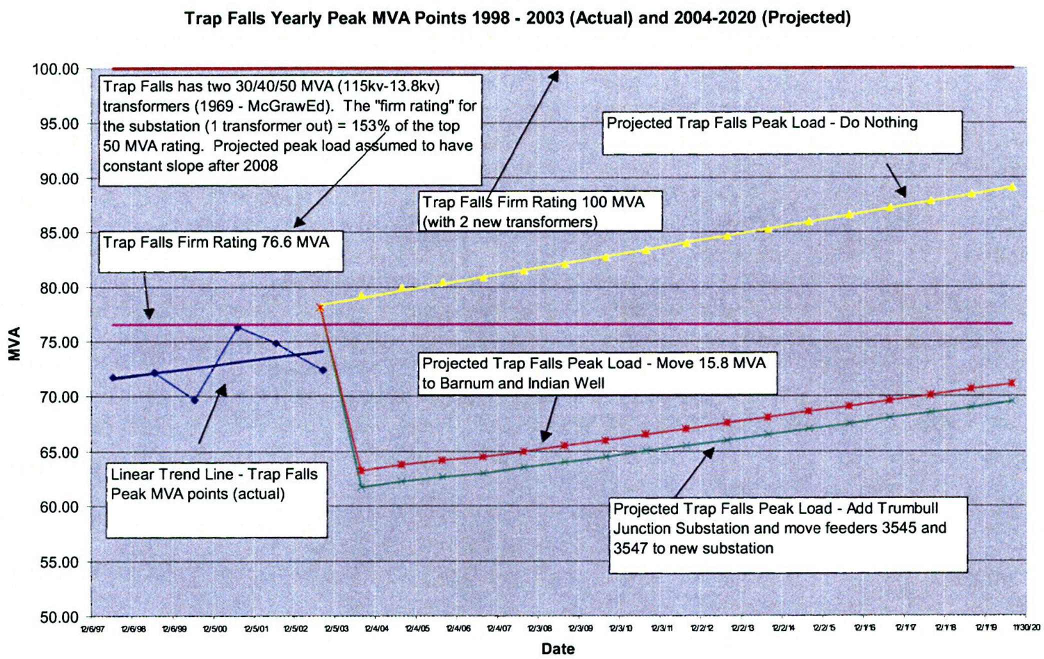

Figure 23 - Evaluating Solution Alternatives Impact on Trap Falls

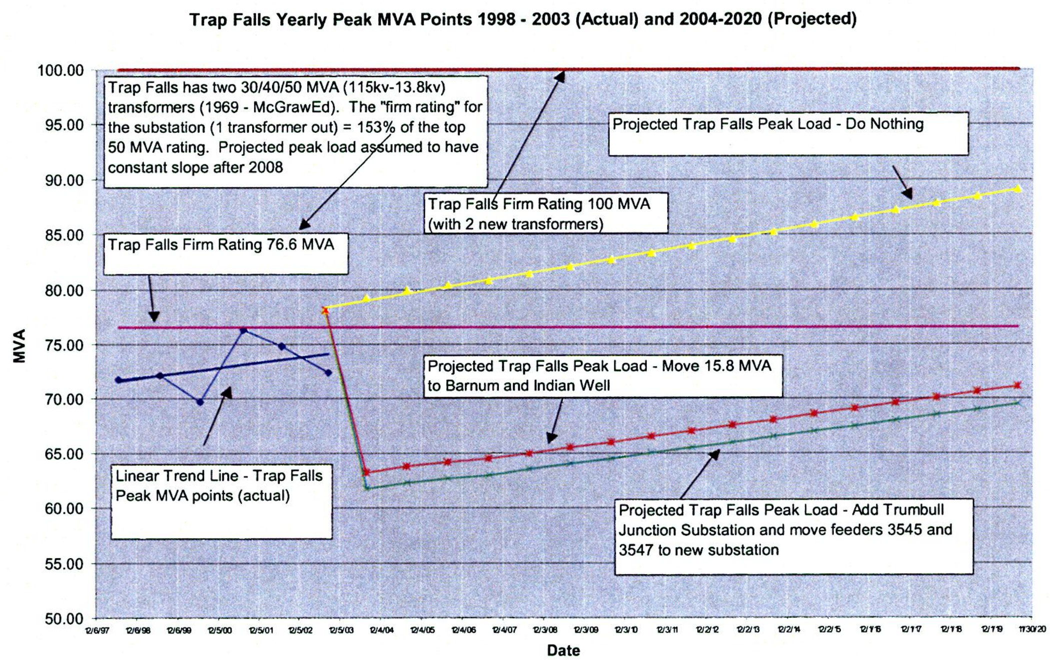

Figure 24 - Evaluating Solution Alternatives Impact on Old Town

The green lines in the above two figures indicate that there is a 5 – 10 % margin between the projected load at Old Town and Trap Falls and their corresponding "Firm ratings" even in the year 2020 provided that the new substation is built and the designated amount of load is relocated to the new substation. As previously stated the construction of the new substation does not resolve the contingency transient voltage stability limit at Old Town, which is 65 MVA.

The new substation at Trumbull Junction is scheduled to have a firm rating of 58 MVA and the initial peak load being transferred to this new substation is about 33 MVA. Assuming a load growth of 2% compounded for 15 years results in a load of 45 MVA being present in the year 2020. Therefore the new Trumbull substation will be operating within its firm rating beyond the year 2020.

References:

1. "TSS - 2.11 Emergency Loading Capability of Sub Power Transformers ", UI, 2/27/91.
2. "UI Preliminary Analysis for Trumbull Substation", UI.
3. Post Transient Voltage Study of UI 115/13.8 kV Bulk Substations, June 26, 1991.
4. Spreadsheet file: "ui txf ratings 08 06 04.xls".
5. EPRI-Technical Update – Representing Load Uncertainty: Stochastic Process Models and Examples, March 2003.
6. Municipal Consultation Filing, Connecticut Siting Council Docket 272
7. The Reliability and Performance of United Illuminating Transmission & Distribution System for 2004, dated April 8, 2005.
8. "Power Transformer Design Enhancements Made to Increase Operational Life", David J. Woodcock and Jeffrey C. Wright, P.E., Weidmann Technical Services Inc.
9. Distribution System Planning Report, AGL, 2002, dated December 2002.
10. "United Illuminating, Trumbull Substation Site Selection Study".
11. Update to Post Transient Voltage Study.
12. 5 Yr Plan substation 2002 non-coincident peak loads.xls.
13. "Old Town and Trap Falls Substation Uprating Study Report", Black and Veatch, dated April 27, 2004.

Appendix A – UI System Diagrams

This appendix contains the following figures:

UI Service Territory
Old Town Substation Single Line (Each Transformer = 115-13.8 kV 36/48/60 MVA
Trap Falls Substation Single Line (Each Transformer = 115-13.8 kV, 30/40/50 MVA
Old Town 13.8 kV Feeders
Trap Falls 13.8 kV Feeders
Old Town Transmission Single Line
Trap Falls Transmission Single Line

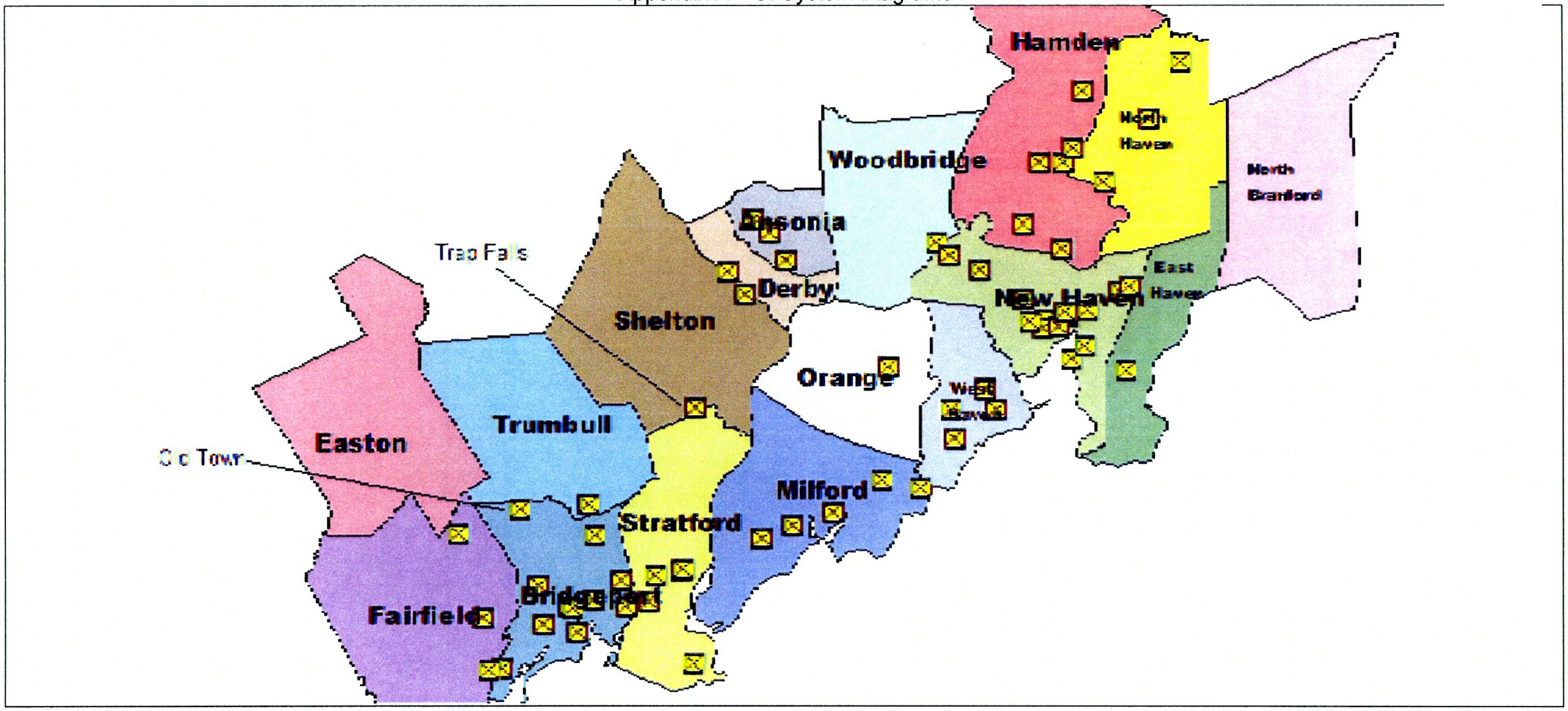

Figure 25 - UI Service Territory

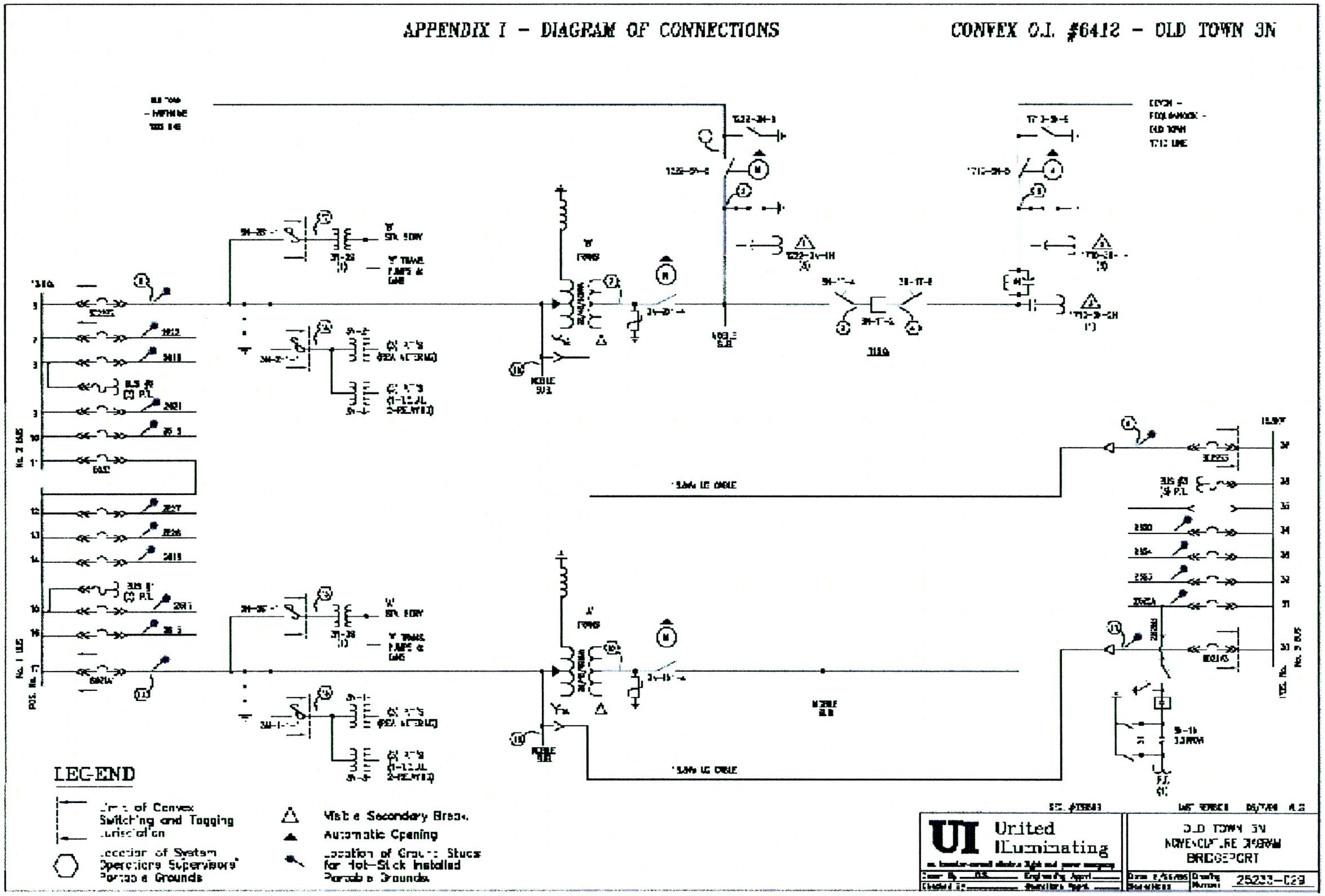

Figure 26 - Old Town Substation Single Line (Each Transformer = 115-13.8 kV 36/48/60 MVA)

Transformer (A&B)Rating = 36/48/60 MVA – For more detail see PDF file above (zoom-able)

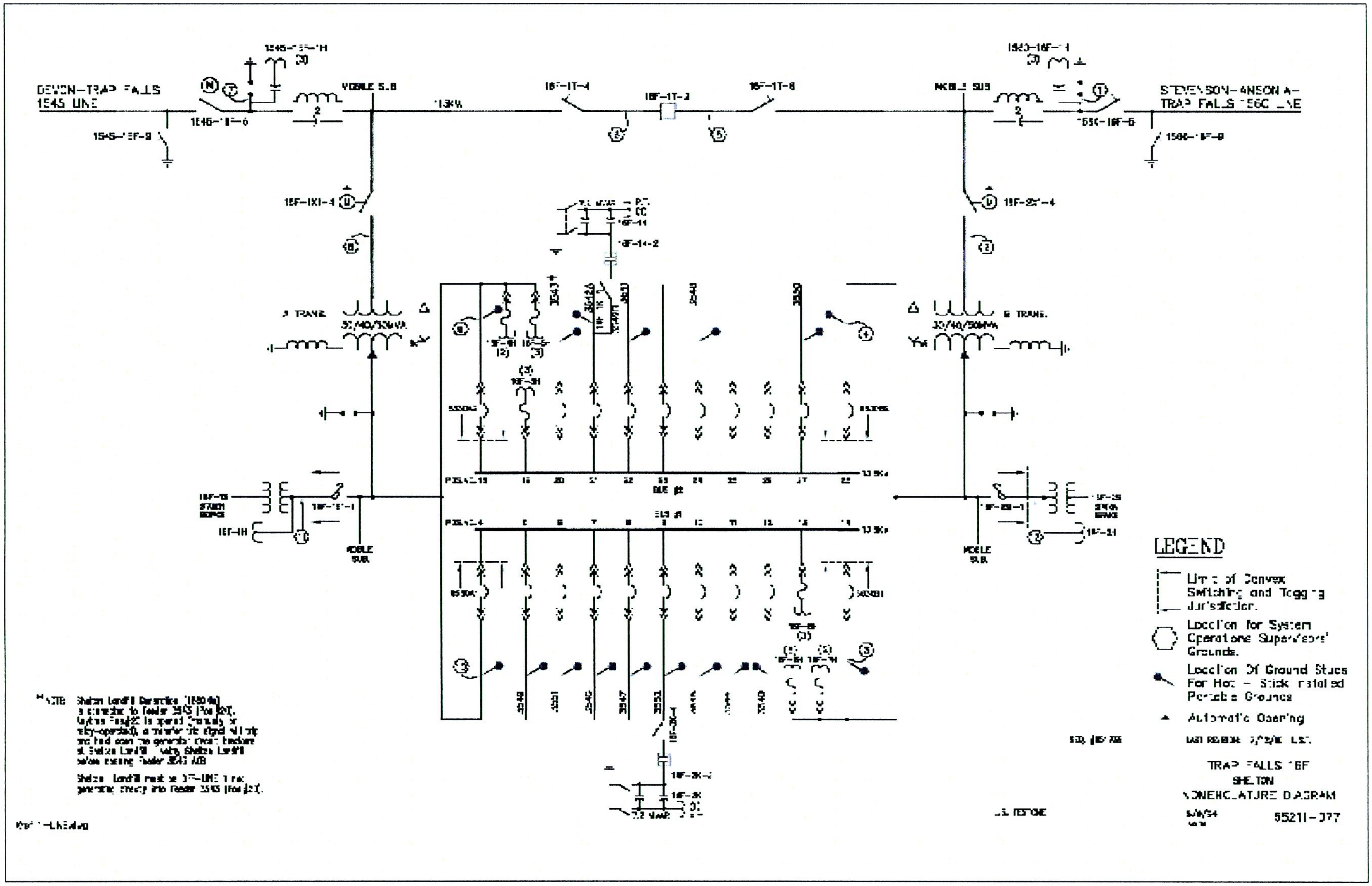

Figure 27 - Trap Falls Substation Single Line (Each Transformer = 115-13.8 kV, 30/40/50 MVA)

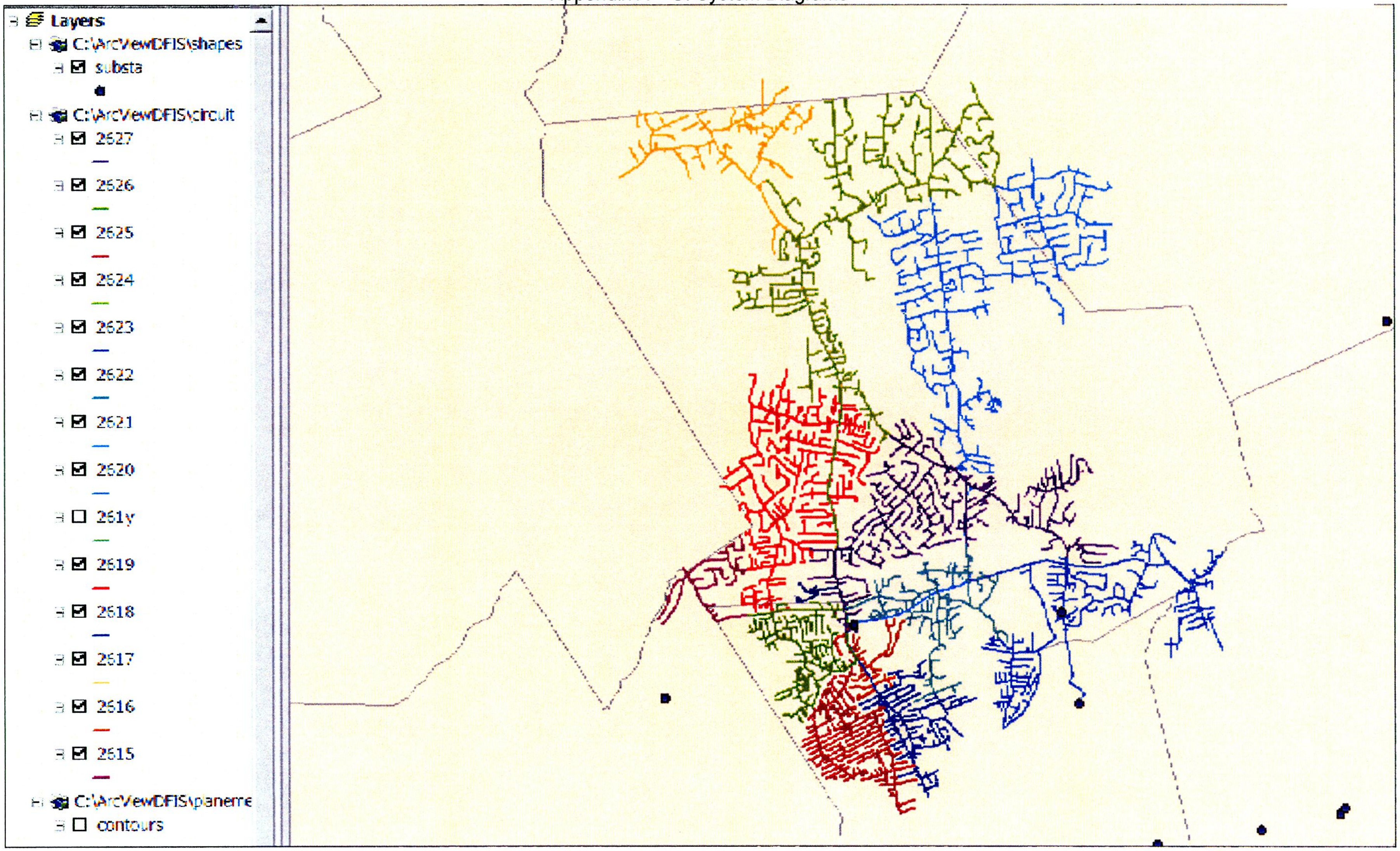

Figure 28 - Old Town 13.8 kV Feeders

Feeders planned to go to new Trumbull substation = 2620 and 2627 (per load forecast spreadsheet)

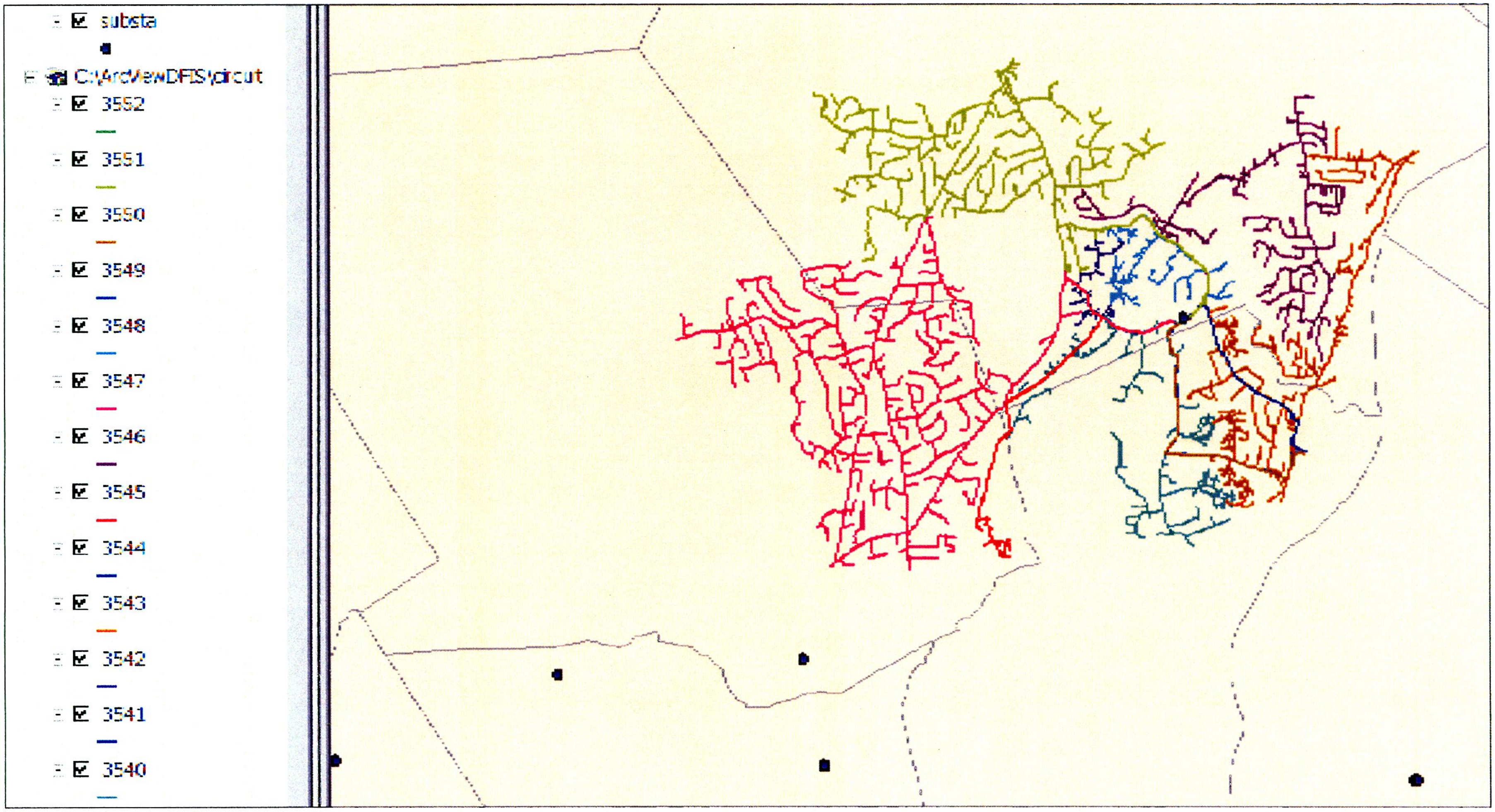

Figure 29 - Trap Falls 13.8 kV Feeders

Feeders planned to go to new Trumbull substation = 3545 and 3547

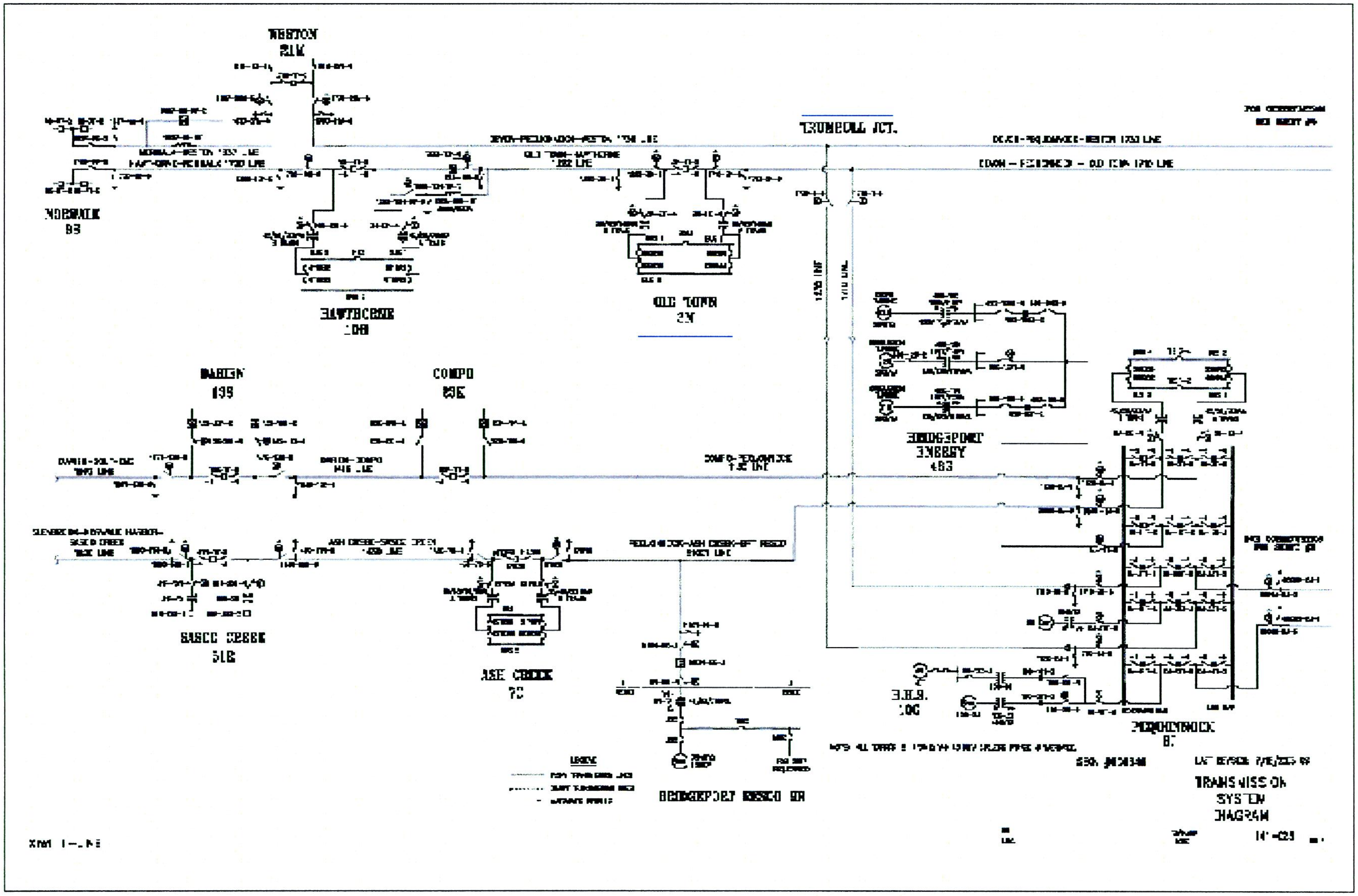

Figure 30 - Old Town Transmission Single Line

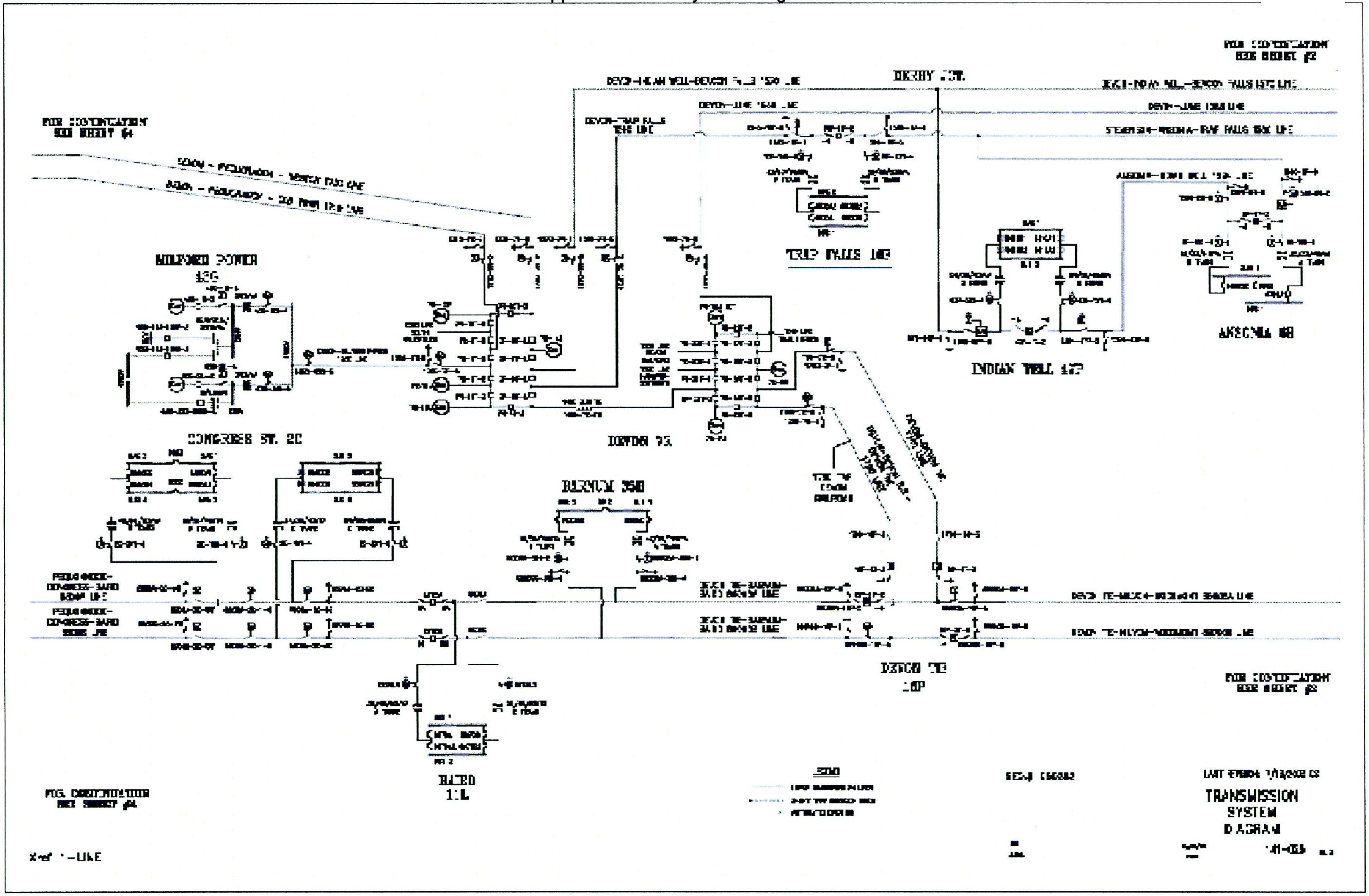

Figure 31 - Trap Falls Transmission Single Line

Appendix B – Weather Normalization Methods

Weather normalization of load data is a mixture of art and science. The procedure that is used varies from one geographic region to another. The weather normalization performed on the load projections in this report largely follow the New England ISO procedure. This is summarized in this appendix and compared to the method used for PJM control area.

ISO NE Formulation

In this formulation, the load is correlated with a weighted 3-day average of a temperature-humidity index (THI) defined as follows:

$$WTHI = \frac{[10THI_d + 5THI_{d-1} + 2THI_{d-2}]}{17} - 55$$

Where

WTHI = Weighted THI
THI_d = THI on day "d"

The THI for a given temperature measurement is defined as

$$THI = 0.5T_{db} + 0.3T_{dew} + 15\ ^{\circ}\mathrm{F}$$

where T_{db} = dry bulb temperature
T_{dew}= dew point temperature

In summary, the WTHI considers the temperature-humidity index for three days running and creates a weighted average that strongly favors the present day but also considers the previous two days. A similar practice is common with utilities in other locations. This WTHI definition is based on 55°F. One might infer from this that 55°F is where it is assumed that cooling load begins to have an effect on the electrical load.

Temperature data for this project came from two sources: UI (Trap Falls substation) and the Bridgeport Sikorsky weather station. The values were quite consistent with the UI data being slightly cooler.

This method was applied to temperature and load data for the last three summers (2002-2004). The WTHI using the UI data was computed for these days and the MW loading was plotted against it for the hottest days of the summer. A WTHI of 26 (UI data) was chosen as the lower cutoff. Below this WTHI, the correlation becomes less distinct.

On the selected hottest days, the slope of the load vs. WTHI is 1.688 MW/degree at Old Town and 1.05 MW/degree at Trap Falls. The trendlines fitted by MS Excel for these values are shown in Figure 32 and Figure 33. Once this trend was known, the loading values were normalized to a design WTHI by adjusting the actual peak load by the difference between the WTHI at the time of the peak and the selected design WTHI.

The UI temperature data was used to determine the most recent sensitivity of load and temperature. The design WTHI was selected from the Bridgeport data. Figure 34 shows the computed WTHI over 55 years for the Bridgeport Sikorsky weather station. The maximums recorded in this time period were nearly 37 degrees. This occurred 4 times in this period, or an average of somewhat less than one such extreme per decade. However, note that two of these events were close together: 1999 and 2001, years that are well-known for extreme power demands. Thus, a WTHI of 37 was chosen as the design value. The weather adjusted loads in Figure 18 and Figure 19 were normalized to this WTHI value using the trend slope determined from the UI data. This value essentially corresponds to an effective temperature of 92°F.

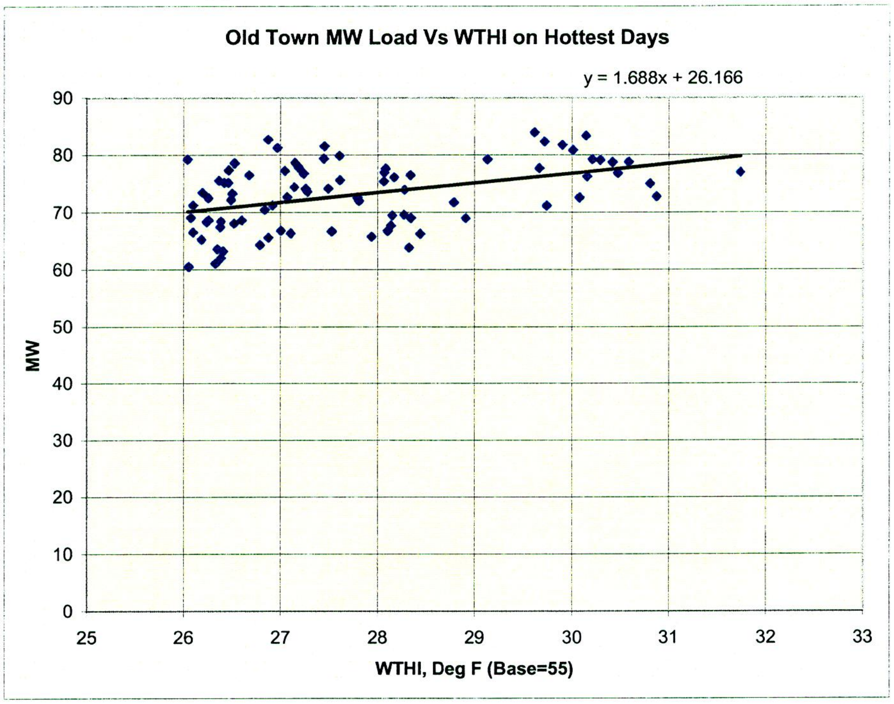

Figure 32. Correlation of MW vs WTHI for Old Town Substation for Hottest Days 2002-2004.

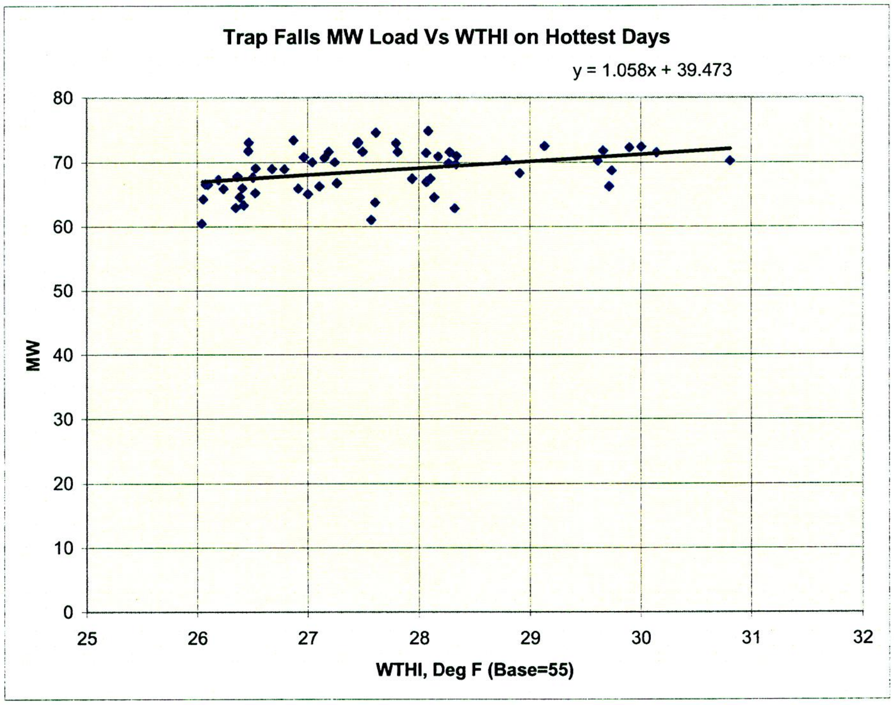

Figure 33. Correlation of MW vs WTHI for Trap Falls Substation for Hottest Days 2002-2004.

For the UI service area, the available temperature quantities were dry bulb temperature and percent relative humidity. A formula for computing the dew point temperature at sea level given these quantities is:

$$T_{dew} = \frac{-430.22 + 237.7\ln(P_{AV})}{-\ln(P_{AV}) + 19.08} \quad °C$$

where

$$P_{AV} = \frac{(RH)P_{SV}}{100} \quad \text{(RH in percent)}$$

$$P_{SV} = 6.11 \times 10^{\left(\frac{7.5T_{db}}{237.7+T_{db}}\right)} \quad T_{db} \text{ in °C}$$

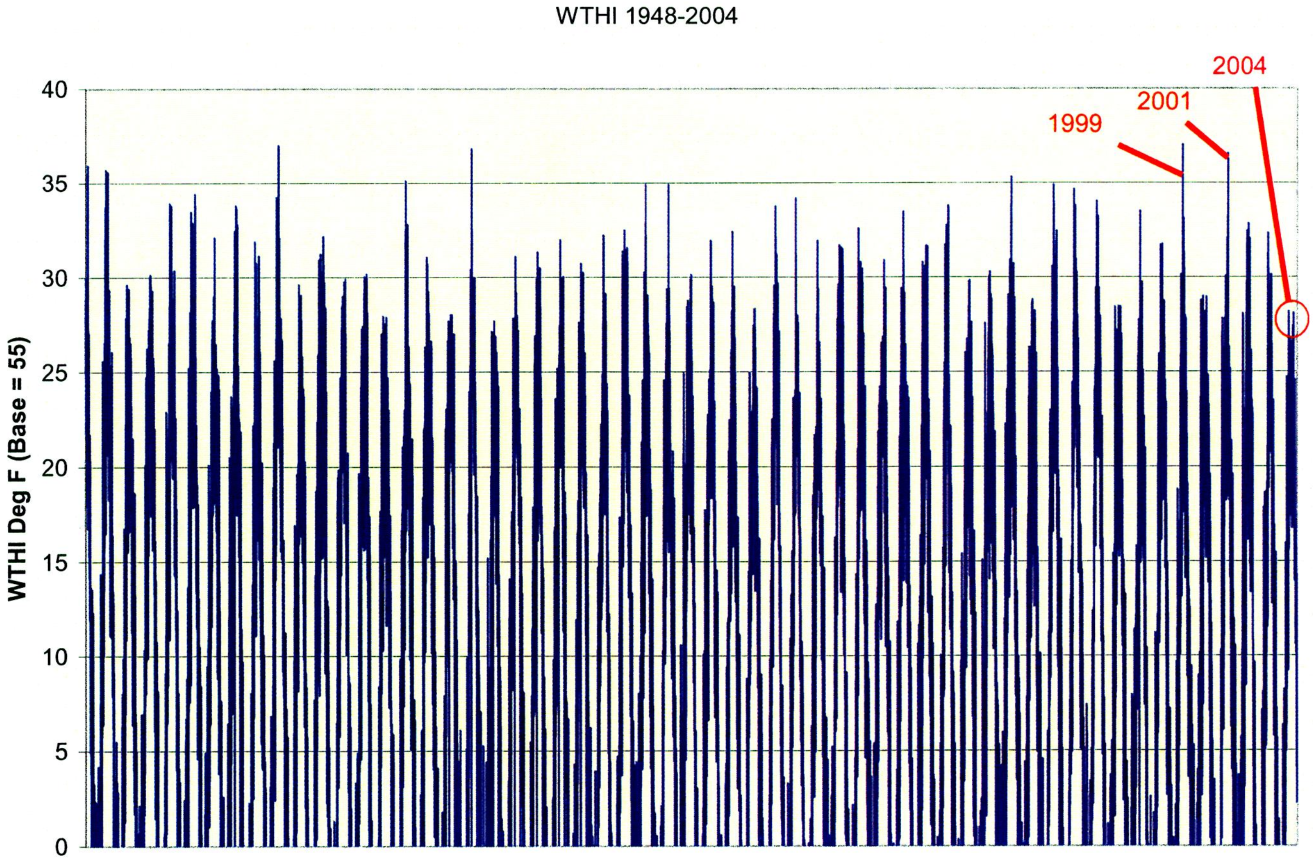

Figure 34. 55-year WTHI computed by NE ISO method for daily maximum temperature and relative humidity readings at Bridgeport Sikorsky station.

This clearly shows that 2004 was a very mild year. The extreme temperatures in 1999 and 2001 that yielded high loading are also quite apparent.

PJM Formulation

The PJM formulae for computing weather normalization for the summer peak in the PJM (East) Control Area are as follows:

Temperature-Humidity Index (THI)

$$THI = DB - 0.55 * (1 - HUM) * (DB - 58)$$

where

DB = Dry bulb temperature (°F)
HUM = Relative Humidity (in per unit)

While this formula is in a different form that the one used by ISO NE, the computed THI is similar. Figure 35 shows a comparison of the values computed by each method. The PJM formulation produces slightly higher THI values by 2-3 degrees on the hotter days, either formulation would seem to be satisfactory.

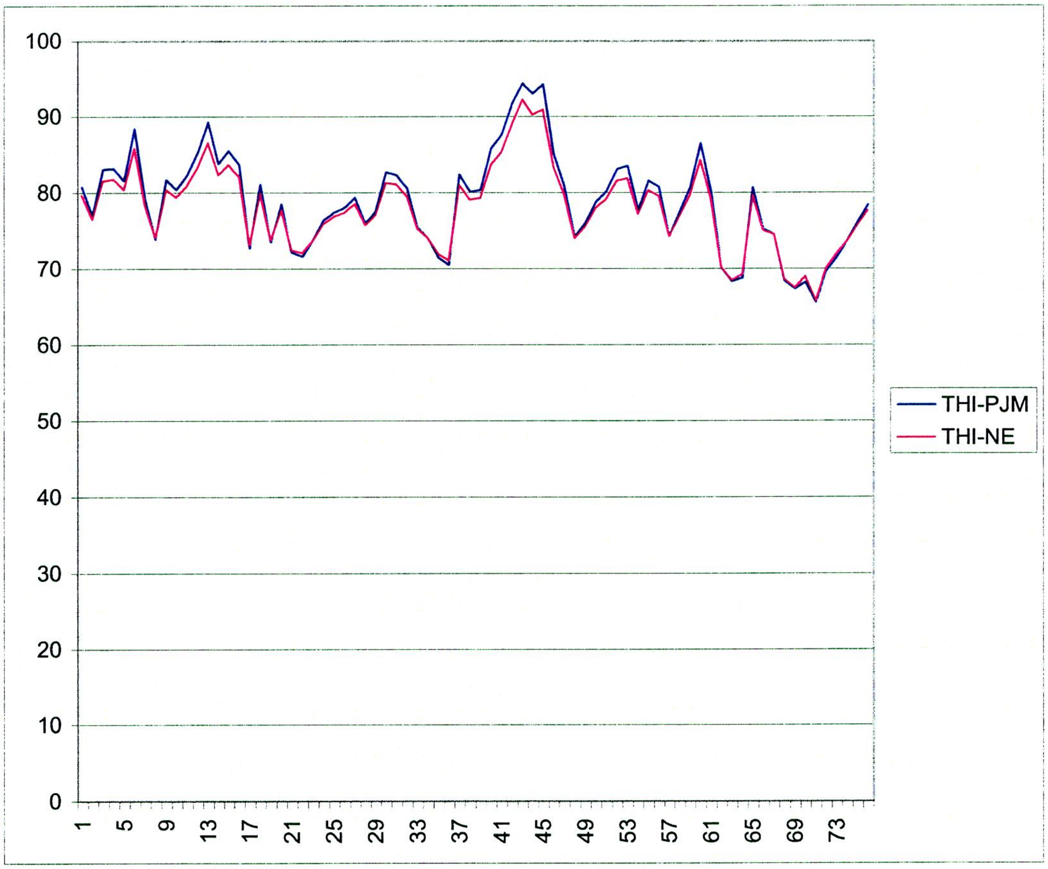

Figure 35. Comparison of THI computed by PJM and NE ISO methods

The next step is to compute the maximum THI (MTHI) for each day between 1400 and 1700 hours. This is a weighted average of three weather stations in the PJM region:

$$MTHI = (5MTHI_n + 3MTHI_p + 2MTHI_w)/10$$

Where $MTHI_n$=Maximum THI (Newark)
$MTHI_p$=Maximum THI (Philadelphia)
$MTHI_w$=Maximum THI (Washington)

Then a two-day weighted THI average is computed using the MTHI values for each day:

$$WTHI = \left[4MTHI_0 + 1MTHI_{-1}\right]/5$$

where $MTHI_0$ = MTHI of current day
$MTHI_{-1}$ = MTHI of previous day

(Interpreted from M19S04V5.doc, PJM Interconnection, L.L.C. "Section 4: Weather Normalization and Peak Allocation". The formulae and notation do not appear to be entirely consistent in this document and the above represents our understanding of what is meant.)

The remainder of the procedure concerns normalization of loads over a 20 year period, which is more appropriate for area forecasting than a particular distribution substation.

To correlate load to WTHI, only values with WTHI > 71 are considered as are weekends and holidays. Also, in an ordinary least squares regression, outliers greater than ± two standard errors are removed.

Appendix C – Trumbull New Loads 2004 – 2009

Number	Town	Substation	Circuit	2004 (kW)	2005 (kW)	2006 (kW)	2007 (kW)	2008 (kW)	2009 (kW)
		Indian Well							
1	Shelton		516			100	100	50	
2.	Shelton		503			500			
3.	Derby		505			200	500	500	500
4.	Derby		505				200	300	200
5.	Derby		505				75	75	
6.	Derby		504	300					
7.	Derby		503		250				
8.	Shelton		503		100				
9.	Shelton		503	375					
10.	Shelton		510			130			
11.	Derby		503		150				
12.	Derby		505		750	250	250		
13.	Shelton		503		50	100	50		
14.	Shelton		503		250				
15.	Shelton		503		100				
16.	Shelton		500			75			
17.	Shelton		510			100	100		
18.	Shelton		516			750	250		
19.	Shelton		505				500	250	
20.	Shelton		510		75				
21.	Shelton		514			50	50	50	
22.	Shelton		510			500	250		
23.	Shelton		503		300				
24.	Shelton		516			1500	500		
25.	Shelton		512			100	200	200	
26.	Shelton		503				100		
27.	Orange		504			240			
28.	Shelton		500			300	300		

Appendix C – Trumbull New Loads 2004-2009

Project Name	Town	Substation	Circuit	2004 (kW)	2005 (kW)	2006 (kW)	2007 (kW)	2008 (kW)	2009 (kW)
		Indian Well							
29.	Shelton		503				150		
30.	Shelton		503			150			
31.	Shelton		516			500			
32.	Shelton		516				500	500	
33.	Shelton		500			100	100		
			Total MVA=	0.75	2.25	6.27	4.64	2.14	0.78
		Old Town							
1.	Trumbull		2620	1000					
2.	Trumbull		2617	300	400	200			
3.	Trumbull		2622	400					
4.	Trumbull		2624			230			
5.	Bridgeport		2623	200					
6.	Trumbull		2620		750				
7.	Trumbull		2620		750	250			
8.	Trumbull		2617		500				
9.	Shelton		2621			100			
10.	Trumbull		2619			50			
11.	Trumbull		2620		750				
12.	Trumbull		2617		150				
13.	Trumbull		2617				50	50	
14.	Trumbull		2617				300		
15.	Trumbull					1200	400		
			Total MVA=	2.11	3.67	2.26	0.83	0.06	0.00

Appendix C – Trumbull New Loads 2004-2009

Project Name	Town	Substation	Circuit	2004 (kW)	2005 (kW)	2006 (kW)	2007 (kW)	2008 (kW)	2009 (kW)
		Trap Falls							
16.	Shelton		3551	50	50	50			
17.	Shelton		3551		200	200	200		
18.	Shelton		3546	60					
19.	Shelton		3548		250	500			
20.	Shelton		3548			750			
21.	Shelton		3542			80	80	50	50
22.	Shelton		3546				200	200	200
23.	Shelton		3543			250			
24.	Shelton		3543				50		
25.	Shelton		3548			1400			
26.	Shelton		3546			600			
27.	Shelton		3542		300				
28	Stratford		3543			210			
29.	Stratford		3543			50			
30.	Stratford		3543			100			
31.	Shelton		3546				250		
32.	Stratford		3543				100	100	50
33.	Stratford		3543				50	50	50
34.	Shelton		3546					150	
			Total MVA=	0.12	0.89	4.66	1.03	0.61	0.39

Note: Power Factor assumed to be 90%. There is an 0.85 Load Coincident Factor taken on all totals