NYISO Transmission System Losses Exploration Study

FINAL REPORT

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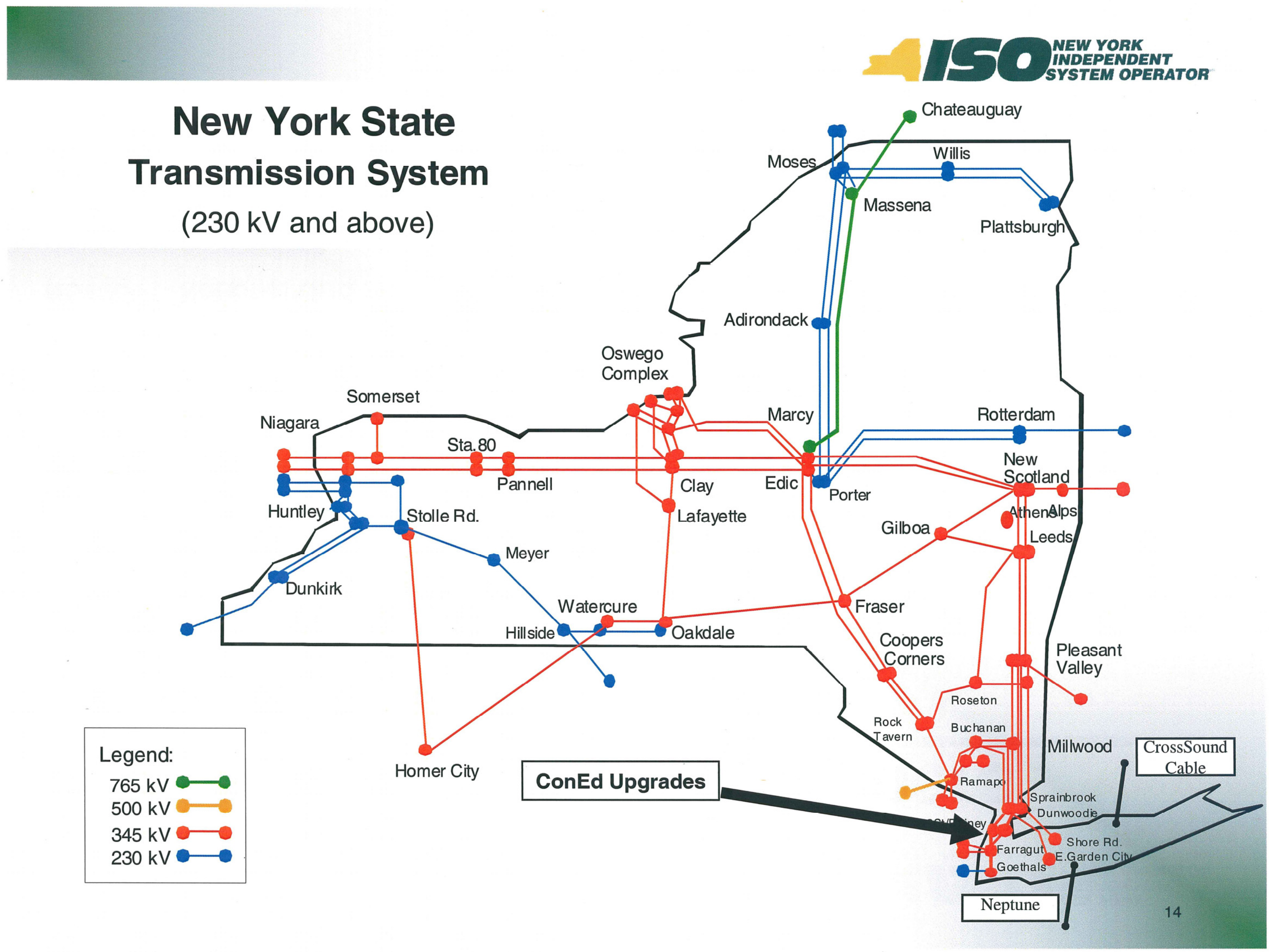
EXECUTIVE SUMMARY

The New York State Public Service Commission commenced its Energy Efficiency Portfolio Standard in June 2008 [1]. In line with this Energy Efficiency goal of the State of New York, the NYISO has engaged ABB Grid Systems Consulting (ABB) to explore transmission system losses with the objective of reducing future transmission losses via installation of capacitor banks or static VAR compensation devices at transmission and sub-transmission substations. The estimated losses, analyses, loss reduction opportunities and recommendations are described in this report.

The NYISO system is a summer peaking system. Analysis of historical losses (past three years) shows that the highest loss occurs during the peak load condition, as expected, but is only for a small number of hours. Lower load levels (60%-80%) occur for almost 2/3 of the year (about 5700 hours), but are interspersed over most of the year. The total losses in this period account for 60-65% of the total annual energy loss. The significance of this observation is that a 1 MW loss reduction during non-peak hours (about 5000 hours in a year) will reduce energy loss by nearly 5000 MWh annually. Further, system operators have more flexibility to make adjustments during lower load levels. Thus, the benefit from reducing losses during non-peak hours is high.

Based on historical operating data and information (for the past three years); seven power flow conditions representative of system operation were established. Then, by utilizing Optimal Power Flow (OPF) techniques, each of the power flow cases were further refined to satisfy established criteria for voltage limits, power transfer levels etc.

[1] Historic Energy Efficiency Program Gets Underway in NY, Transmission & Distribution, June 19, 2008, 10:41am, NYSPSC.


NEW YORK INDEPENDENT SYSTEM OPERATOR
New York State
Transmission System
(230 kV and above)
Chateauguay
Moses
Willis
Massena
Plattsburgh
Adirondack
Oswego
Complex
Somerset
Niagara
Sta. 80
Pannell
Marcy
Rotterdam
New
Scotland
Clay
Edic
Porter
Huntley
Stolle Rd.
Lafayette
Athens
Alps
Gilboa
Leeds
Meyer
Dunkirk
Watercure
Fraser
Hillside
Oakdale
Coopers
Corners
Pleasant
Valley
Roseton
Rock
Tavern
Buchanan
Millwood
CrossSound
Cable
Homer City
ConEd Upgrades
Ramapo
Sprainbrook
Dunwoodie
Shore Rd.
Farragut
E.Garden City
Goethals
Neptune
Legend:
765 kV
500 kV
345 kV
230 kV
14

Calculated Load Loss: For an assumed peak load condition of 33,200 MW; the calculated load demand (capacity) loss is 979 MW (about 2.95% of native load). The load energy loss is 5,727 GWh (3.42% of 167,390 GWh annual load energy).

Loss Reduction Measures/Opportunities:

Hardware Installation Options: The application of shunt compensation (capacitors); particularly when in the vicinity of loads, has two main consequences. One is capacity release and the other is loss reduction. In this study, only possible reduced losses are calculated.

The analyses suggest that in order to be economically attractive, the strategies must allow for compensation at lower (i.e., below 115 kV) voltage levels. The results show that assuming an additional 1,338 Mvars in compensation, savings could be in the order of 50,000 MWh per year. Assuming $100 per MWh of energy cost, this translates into a 5 million dollar saving per year. Depending on the capital cost assumptions (varies by size, location and voltage level); the benefit to cost ratio will be in the range of one to four.

On the other hand, under a more aggressive deployment assumption of 2,323 Mvars in compensation, savings could be in the order of 71,000 MWh per year, although with some slight reduction in benefit to cost ratio.

Further, the 1,338/2,323 Mvar compensation are not an “all or nothing” proposition. Compensation can be added incrementally; starting with the “low hanging” fruit where the impact of compensation on losses is highest, thereby giving a higher benefit to cost ratios or shorter payback duration.

Voltage Adjustments and Control: One of the main operational responses for reducing transmission losses is to minimize reactive power flows on the transmission system by voltage scheduling and control. The system operators constantly and continuously adjust voltages utilizing i) generator terminal voltage control, ii) on-load transformer taps (LTCs) and iii) switched shunts. However, the focus is on system security, as it should be, and the adjustments are mostly determined by regular or conventional power flow solutions. Consequently these adjustments are local in nature.

In this study, a further objective of minimizing losses was evaluated by allowing these adjustments on a system-wide basis by using Optimal Power Flow (OPF) techniques. This allows global adjustments as compared to local adjustments. The simulation cases suggest significant loss reduction opportunities (potentially as much as 300,000 MWh/Year, i.e., in excess of 30M$/year), when utilizing existing reactive-type controls (transformer taps, existing switched shunts, and generator voltages) for loss minimization.

However, all the anticipated reduction in losses may not materialize due to various day-to-day operational constraints. Under certain load and operating conditions, a higher savings in losses may be possible with this type of adjustment. Once again, this is not an “all of nothing” proposition. Ideally, such consideration would take place at, say, every hour (through use of OPF sensitivities, for example). But even a day ahead analysis would likely be helpful in reducing system losses.

The cost for making the adjustments is small as compared to hardware based solutions. If assuming the cost of additional manpower, software etc is in the order of a million dollars per year, the estimated benefit to cost ratio is 30. Due to reasons mentioned earlier, the benefit may be somewhat less in practice. However, these calculations do indicate that system voltage adjustments are a very cost effective method for reducing losses.

Implementation Considerations: One of the key items required to reduce losses during operations is use of an Optimal Power Flow (OPF) software program. Prior to implementing real-time OPF, it is advisable to conduct off-line studies to understand specific impacts of system voltage adjustment. Initial OPF training by the software vendor(s) for the engineers in both Planning and Operations is recommended. This should be followed-up by applications training to provide proficiency in using OPF for simulating the loss reduction impacts of voltage control and LTC adjustments.

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1 INTRODUCTION

The New York State Public Service Commission commenced its Energy Efficiency Portfolio Standard in June 2008 [2]. In line with this Energy Efficiency goal of the State of New York, the NYISO has engaged ABB Grid Systems Consulting (ABB) to explore transmission system losses with the objective of reducing future transmission losses via installation of capacitor banks or static VAR compensation devices at transmission and sub-transmission substations.

The New York wholesale electricity market is divided into eleven pricing or load zones. Figure 1.1 presents the geographical boundaries for these pricing zones. The development of these load zones was driven primarily by the topology or configuration of the transmission system and secondarily by the franchise areas of the investor owned utilities. These load areas were initially developed by the New York Power Pool after the 1965 Northeast blackout as part of a process of identifying critical bulk power system transmission interfaces. Subsequently, these load zones were utilized to define pricing zones for the wholesale electricity market.

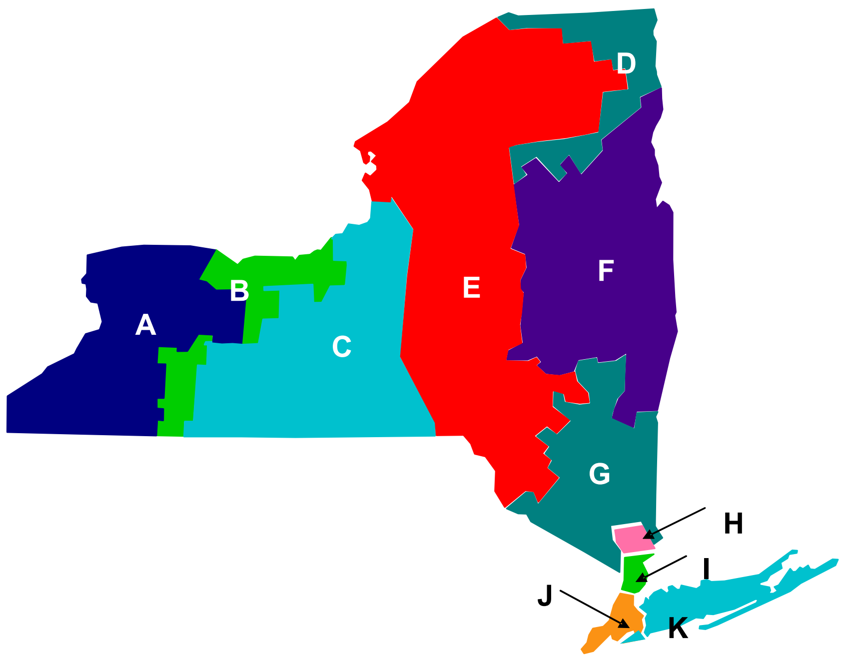


Figure 1.1 – New York Load Zones

The transmission losses exploration in this study were approached on a zonal basis based on observed low voltage profiles, poor power factors at transmission substations, starting from zones F through I.

This report is organized as follows:

- Conclusions and recommendations are summarized in Section 2.

[2] Historic Energy Efficiency Program Gets Underway in NY, Transmission & Distribution, June 19, 2008, 10:41am, NYSPSC.

- The methodology followed in defining seven powerflow cases representing system performance throughout the load cycle is described in Sections 3 through 9.
- In Section 10, use of Optimal Power Flow techniques in deriving the sensitivity of MW losses to injections of Active and Reactive power is described.
- In Section 11, the potential use of existing controls to minimize MW losses is examined.
- In Section 12, the use of new shunt compensation at 115 kV and above Substations for loss reduction is investigated.
- The analyses are repeated in Section 13, with the difference that additional compensation is allowed at all voltage levels.
- In Section 14, the effect of a more aggressive policy towards loss reduction with additional compensation is illustrated.
- The impact of MW loss reduction on reactive losses is examined in Section 15.
- A cursory analysis of the potential reliability benefits of deployment of loss-related additional compensation is included in Section 16.

2 CONCLUSIONS AND RECOMMENDATIONS

2.1 STUDY METHODOLOGY

The application of shunt compensation; particularly when in the vicinity of loads, has two main consequences. One is capacity release, the other is loss reduction.

Whereas capacity (transmission and generation) release may be studied by focusing on peak load conditions, the analysis of loss reduction must consider all conditions, ranging from peak load to light load.

Significant effort was invested in developing seven powerflow conditions representative of system operation throughout the load cycle. Optimal Powerflow (OPF) techniques were found to be an expedient means of deriving such base cases, all meeting the same established criteria.

Also with help from OPF techniques compensation strategies for loss reduction utilizing additional shunt compensation as well as existing “reactive-type” controls (shunt compensation, transformer taps, and generator voltages) were derived.

2.2 LOSS REDUCTION WITH ADDITIONAL COMPENSATION

The analyses suggest that in order to be economically attractive, the strategies must allow for compensation at lower (i.e., below 115 kV) voltage levels. The results show that assuming an additional 1,338 Mvars in compensation, savings could be in the order of 50,000 MWh per year. Assuming $100 per MWh saved, this translates into a 5 million dollar saving per year. Assuming further a compensation cost of $6,000 per MWh, and a 15% annual cost of capital, the benefit/cost ratio of such compensation strategy was found to be in the order of 4.2, thus suggesting the use of new compensation to reduce active power losses to be economically feasible.

Further, if a more aggressive deployment 2,323 Mvars in compensation is assumed, savings could be in the order of 71,000 MWh per year, although with some slight reduction in benefit/cost ratio to 3.4.

Of most importance in reducing energy losses is the strategic control of compensation during off-peak hours. This will likely require consideration of losses in system operations and/or implementation of controls monitoring flows and voltages at key stations and switching in and out existing and new compensation as necessary. In some cases, adjustment of transformer taps and/or of generation voltages to accommodate such compensation changes may be required.

This is not an “all or nothing” proposition. Compensation can be added incrementally; starting with the “low hanging” fruit where the impact of compensation on losses is highest. OPF techniques can help in determining what those opportunities are. Conversely, if additional loss reduction is desired, OPF techniques can be employed to identify additional (although somewhat less effective) compensation opportunities.

Neither should OPF suggestions be viewed as “all or nothing”. Instead they should be viewed as providing “expert system-type” guidance as to where opportunities for loss reduction are and in what amounts. Final strategies taking into account space limitations, and the need to discretize and consolidate are best left to those familiar with the particular network(s) to design.

2.3 LOSS REDUCTION WITH EXISTING CONTROLS

The studies also suggest significant loss reduction opportunities (potentially as much as 300,000 MWh/year, i.e., in excess of 30M$/year), when utilizing existing reactive-type controls (transformer taps, existing switched shunts, and generator voltages) for loss minimization. This, however, would require consideration of losses during the operation of the system.

Once again, this is not an “all of nothing” proposition. Ideally, such consideration would take place at, say, every hour (through use of OPF sensitivities, for example). But even a day ahead analysis would likely be helpful in reducing system losses.

It is important to note the emphasis on “reducing future transmission losses” in the objective for these studies. Today’s LD1 conditions will likely become tomorrow’s LD2 or LD3 conditions. Thus, all things being equal (i.e., barring new transmission, for example), loss-reduction strategies are likely to become more attractive with the passage of time.

2.4 IMPLEMENTATION CONSIDERATIONS:

One of the key items required to reduce losses during operations is use of an Optimal Power Flow (OPF) software program. Prior to implementing real-time OPF, it is advisable to conduct off-line studies to understand specific impacts of system voltage adjustment. Initial OPF training by the software vendor(s) for the engineers in both Planning and Operations is recommended. This should be followed-up by applications training to provide proficiency in using OPF for simulating the loss reduction impacts of voltage control and LTC adjustments.

3 DEFINITION OF REPRESENTATIVE POWER FLOW CONDITIONS / CASES

At the beginning of the studies NYISO provided ABB with a PSS/E case corresponding to the peak load conditions in 2008. The name of such case was *s08pktr6_060908_2_2_clay_conEd_ABB.sav*. As discussed below, however, peak load conditions pertain to only a small fraction of a system's operating conditions throughout the year.

Hence, the 2008 peak load conditions were utilized only as a starting point for development of powerflows providing a better representation of the expected loss performance of the system. A total of seven such powerflow cases were developed. This section describes the rationale for selection of such cases.

3.1 LOAD PROFILE AND DURATION

3.1.1 System Load Profile

The NYISO system is a summer peaking system. Loads in a system are however constantly varying. Due to the non-linear nature of load losses ($I^2 R$ relationship), a more accurate calculation of losses is obtained if it can be performed at every hour. However, this entails performing 8760 power flow calculations. In fact, the difficulty or time spent is not in making the power flow runs; but in preparing suitable system conditions (generation dispatch, switching capacitors, reactors etc) for these hourly conditions. This preconditioning of the system model for the power flow solution takes a significant amount of engineering time. Thus, irrespective of the methodology used, some type of approximation of the varying load shape is necessary.

The NYISO has provided ABB with load information from the past three years. By considering the past three years, any differences due to weather and other consumer utilization patterns for a particular year are averaged and thus a better representation of future load profiles is attained. This load profile was converted into a load duration curve and then approximated with a 7-step load duration curve by clustering the load levels where most of the load occurs.

NYISO provided 8760 hourly load data [3] for each year between September 01, 2005 and August 31, 2008. To represent the load profile for these three years, the following steps were taken to come up with the average load duration curve:

1. Finding the peak load of each year (Table 3.1)
2. "Per – unitizing" the hourly load data by dividing the load values by the corresponding peak load for that year (%)
3. Averaging the three-year "per-unitized" loads at each hour
4. Sorting the averaged data in descending order so as to plot the Load Duration Curve

Table 3.1: NYCA Peak load demand

Year	Peak Load (MW)	Peak Date	Peak Time
9/1/2007 ~ 8/31/2008	32,432	6/9/2008	16:00
9/1/2006 ~ 8/31/2007	32,169	8/8/2007	16:00
9/1/2005 ~ 8/31/2006	33,934	8/2/2006	13:00

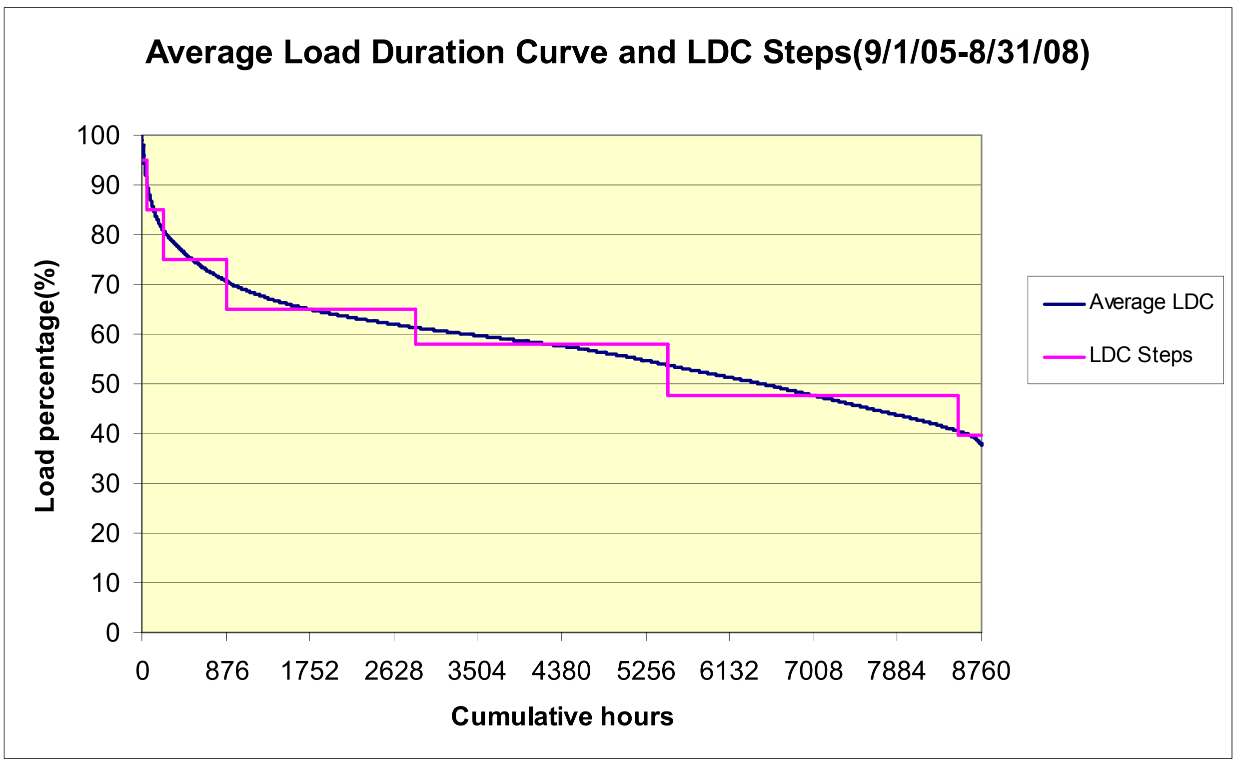
[3] Since 2008 is a leap year, the data for February 29, 2008 was removed for consistency

This average load duration curve was then approximated with a 7-step load duration curve as shown in Table 3.2 and Figure 3.1. It can be seen that the 7 steps are good approximations of the average smooth curve. Calculations also showed that the maximum error at each step due to the approximation is 0.08% (i.e., maximum distance between steps and average LDC).

Table 3.2: Load Duration Steps

LDC Step	Upper Range(%)	Lower Range(%)	LDC Step Load(%)	LDC Step Hours
1	100.0	90.0	95.0	48
2	90.0	80.0	85.0	178
3	80.0	70.0	75.0	665
4	70.0	60.0	65.0	1958
5	60.0	52.5	58.0	2633
6	52.5	40.0	47.7	3036
7	40.0	37.5	39.6	242

Figure 3.1: Normalized Annual Load Duration Curve and LDC Steps



3.1.2 Zonal Load Profile

Section 3.1.1 describes how the average NYCA (New York Control Area) load duration curve was approximated with 7 steps. NYCA is comprised of 11 (eleven) zones as listed in Table 3.3.

Each zone has its own unique load profile and thus it should be studied separately for each step. NYISO provided ABB with historical data for hourly load data for each zone for the past three years. These zonal load data were "per-unitized" with respect to the peak load at that year. Next, the "per-unitized" hourly loads were fitted into the ranges of the 7 LDC steps and then averaged within each range. Tables 3.4 through 3.6 show the results from such analyses for each of the three years.

Table 3.3: NYCA Zones

Zone No.	Zone Letter	Zone Name
1	A	WEST
2	B	GENESSE
3	C	CENTRAL
4	D	NORTH
5	E	MHK VL
6	F	CAPITAL
7	G	HUD VL
8	H	MILLWD
9	I	DUNWOD
10	J	N.Y.C.
11	K	LONGIL

For each LDC step, the zonal load data for each of the three years were in turn averaged and are summarized in Table 3.7. Because the combined total load percentages at each LDC step are different from those in the fourth column in Table 3.2, each row in Table 3.7 was scaled to attain the desired values. The results from such scaling are shown in Table 3.8. It should be noted that the first step (LD1) was scaled up to 100% from 94.39% (as opposed to 95%). This was done in order to ensure a peak load condition is examined as the first load step. Because the duration time for this step being so small (48 hours compared with 8760 hours total), the impact of such approximation is expected to be negligible.

The peak load for this study is assumed to be 33,200 MW. Based on the percentage zonal load profile in Table 3.8, representative zonal load demands (MW) for each step were derived and are shown in Table 3.9.

Table 3.4: Load Profile at each zone (9/1/2007 ~ 8/31/2008) (%)

Steps	Hours	A	B	C	D	E	F	G	H	I	J	K	Total
1	43	7.49	5.46	8.32	2.44	3.92	6.51	6.56	1.82	4.01	32.23	15.10	93.87
2	239	7.01	4.85	7.42	2.40	3.55	5.68	5.68	1.54	3.42	28.96	13.11	83.61
3	784	6.51	4.34	6.89	2.40	3.31	5.09	4.92	1.34	2.92	25.57	11.13	74.41
4	2814	6.13	3.92	6.46	2.45	3.07	4.54	4.11	1.13	2.36	21.25	8.76	64.17
5	2201	5.50	3.45	5.83	2.35	2.71	4.02	3.64	0.95	2.06	18.63	7.53	56.67
6	2600	4.79	2.88	5.02	2.26	2.28	3.30	2.99	0.73	1.64	15.20	5.99	47.07
7	79	4.04	2.35	4.22	2.08	1.86	2.71	2.45	0.57	1.32	12.82	4.88	39.30

Table 3.5: Load Profile at each zone (9/1/2006 ~ 8/31/2007) (%)

Steps	Hours	A	B	C	D	E	F	G	H	I	J	K	Total
1	77	8.00	5.76	8.50	2.47	3.90	6.58	6.66	1.69	4.03	31.87	15.05	94.50
2	233	7.25	4.99	7.69	2.41	3.59	5.91	5.84	1.43	3.50	28.60	12.89	84.10
3	709	6.68	4.40	7.04	2.42	3.31	5.24	4.94	1.25	2.97	24.78	10.89	73.92
4	2874	6.26	3.98	6.54	2.41	3.02	4.60	4.14	1.08	2.49	21.02	8.73	64.27
5	2187	5.61	3.52	5.90	2.32	2.68	4.08	3.68	0.94	2.16	18.32	7.61	56.81
6	2614	4.86	2.91	5.04	2.21	2.18	3.32	3.01	0.71	1.71	14.92	5.99	46.86
7	66	4.05	2.45	4.30	2.05	1.76	2.74	2.50	0.51	1.41	12.72	4.98	39.48

Table 3.6: Load Profile at each zone (9/1/2005 ~ 8/31/2006) (%)

Steps	Hours	A	B	C	D	E	F	G	H	I	J	K	Total
1	52	7.60	5.69	8.49	2.21	3.81	6.45	6.76	1.69	4.19	32.09	15.83	94.81
2	134	7.19	5.13	7.75	2.24	3.49	5.87	5.80	1.47	3.65	28.83	13.32	84.74
3	616	6.54	4.42	6.90	2.19	3.10	5.13	4.99	1.26	3.15	25.60	11.42	74.71
4	1708	6.10	3.87	6.48	2.25	2.91	4.49	4.14	1.05	2.55	21.03	9.05	63.92
5	2776	5.62	3.52	5.93	2.19	2.60	3.95	3.60	0.88	2.22	18.38	7.61	56.51
6	2974	4.79	2.88	5.11	2.10	2.13	3.24	3.01	0.72	1.75	14.87	6.10	46.70
7	500	3.63	2.05	3.73	1.67	1.44	2.22	2.10	0.43	1.22	10.46	4.14	33.09

Table 3.7: Average Load Profile at each zone (9/1/2005 ~ 8/31/2008) (%)

Steps	A	B	C	D	E	F	G	H	I	J	K	Total
1	7.70	5.64	8.44	2.37	3.88	6.51	6.66	1.73	4.08	32.06	15.32	94.39
2	7.15	4.99	7.62	2.35	3.55	5.82	5.77	1.48	3.52	28.80	13.11	84.15
3	6.58	4.39	6.94	2.34	3.24	5.15	4.95	1.28	3.02	25.32	11.15	74.34
4	6.16	3.92	6.49	2.37	3.00	4.54	4.13	1.08	2.47	21.10	8.85	64.12
5	5.58	3.50	5.89	2.29	2.66	4.02	3.64	0.92	2.14	18.44	7.58	56.66
6	4.81	2.89	5.06	2.19	2.20	3.29	3.00	0.72	1.70	15.00	6.03	46.88
7	3.90	2.28	4.08	1.93	1.69	2.56	2.35	0.50	1.32	12.00	4.67	37.29

Table 3.8: Adjusted Average Load Profile at each zone (9/1/2005 ~ 8/31/2008) (%)

Steps	A	B	C	D	E	F	G	H	I	J	K	Total
1	8.15	5.97	8.94	2.51	4.11	6.90	7.06	1.84	4.32	33.97	16.23	100.00
2	7.22	5.04	7.70	2.37	3.58	5.88	5.83	1.50	3.56	29.09	13.24	85.00
3	6.64	4.42	7.00	2.36	3.27	5.20	4.99	1.29	3.04	25.54	11.24	75.00
4	6.25	3.98	6.58	2.40	3.04	4.61	4.19	1.10	2.50	21.39	8.97	65.00
5	5.71	3.58	6.03	2.34	2.73	4.11	3.73	0.94	2.19	18.88	7.76	58.00
6	4.90	2.94	5.15	2.23	2.23	3.35	3.06	0.73	1.73	15.26	6.13	47.70
7	4.15	2.42	4.34	2.05	1.79	2.72	2.50	0.53	1.40	12.74	4.96	39.60

Table 3.9: Representative Zonal Load Profile (MW)

Steps	Hours	A	B	C	D	E	F	G	H	I	J	K	Total
1	48	2707	1983	2968	834	1364	2291	2343	610	1434	11277	5390	33200
2	178	2398	1673	2555	788	1189	1952	1936	497	1181	9657	4396	28220
3	665	2203	1469	2326	783	1085	1726	1658	429	1010	8479	3733	24900
4	1958	2075	1321	2185	797	1010	1529	1390	365	830	7101	2977	21580
5	2633	1895	1188	2001	777	905	1365	1238	314	729	6268	2577	19256
6	3036	1626	976	1709	739	742	1111	1015	243	573	5066	2037	15836
7	242	1377	805	1440	682	594	902	829	178	464	4231	1646	13147

4 REACTIVE POWER SCALING

4.1 INTRODUCTION

As described in Section 3, in order to attain a more representative model of the NYISO loss performance throughout the year, seven powerflow cases were developed. The starting point for all such cases was case *s08pktr6_060908_2_2_clay_conEd_ABB.sav* provided by the NYISO. Described in Section 3 is how the MW parts of zonal loads in such case were scaled in order to attain each of the seven "Load Step" cases. This section describes how the reactive parts of such loads were set.

4.2 REACTIVE POWER LOAD SCALING

EMS data were used as the basis for scaling the reactive part of loads. ABB requested NYISO to provide at least three EMS snapshots for each LDC step. Because loads in EMS cases are assumed at different voltage levels than in the NYISO planning PSS/E cases, Q/P ratios are not comparable and thus were not directly utilized. Instead changes in Q/P ratios with respect to their EMS cases' peak load counterparts were calculated and those changes were applied to the aforementioned 2008 peak load case provided.

At each LDC step, every EMS snapshot contains the zonal load data. However, since the peak load of each year is different, ABB first per-unitized the zonal loads with respect to the corresponding yearly peak load EMS snapshot. Thus the Q/P ratio in each zone of each snapshot was calculated. Then, for each zone, the average of the Q/P ratios among all snapshots was obtained. The final results are shown in Table 4.1.

Table 4.1: Average Load Q/P Ratio in each zone for each LDC step

Step	A	B	C	D	E	F	G	H	I	J	K
1	0.3616	0.2848	0.3468	0.4731	0.3829	0.3838	0.2751	0.2532	0.0692	0.2568	0.2754
2	0.3405	0.3231	0.3247	0.4414	0.3692	0.3573	0.2460	0.1753	0.0085	0.2174	0.2876
3	0.2759	0.3428	0.2851	0.4437	0.3483	0.3344	0.1989	0.0742	-0.0821	0.1952	0.3177
4	0.2973	0.3638	0.2938	0.4629	0.3714	0.3426	0.2070	0.0581	-0.0227	0.1905	0.3420
5	0.3220	0.3809	0.3216	0.4662	0.4155	0.3654	0.2135	0.0583	-0.1010	0.1982	0.4130
6	0.3210	0.4725	0.3427	0.4750	0.4712	0.3784	0.2317	0.0795	-0.0188	0.2328	0.4577
7	0.5033	0.4904	0.4012	0.5138	0.5286	0.4672	0.2298	0.0744	-0.0150	0.2086	0.5961

It can be seen that the Q/P ratios for zones H & I are not reasonable. Hence, instead, the Q/P averages for zones G & J were utilized instead for those two zones. Additionally, the Q/P ratio for Zone K in Step 7 is exceptionally higher than in previous steps. Hence a value close to that in Step 6 was used instead.

Table 4.2: Adjusted load Q/P Ratio in each zone for each LDC step

Step	A	B	C	D	E	F	G	H	I	J	K
1	0.3616	0.2848	0.3468	0.4731	0.3829	0.3838	0.2751	0.2659	0.2659	0.2568	0.2754
2	0.3405	0.3231	0.3247	0.4414	0.3692	0.3573	0.2460	0.2317	0.2317	0.2174	0.2876
3	0.2759	0.3428	0.2851	0.4437	0.3483	0.3344	0.1989	0.1970	0.1970	0.1952	0.3177
4	0.2973	0.3638	0.2938	0.4629	0.3714	0.3426	0.2070	0.1987	0.1987	0.1905	0.3420
5	0.3220	0.3809	0.3216	0.4662	0.4155	0.3654	0.2135	0.2058	0.2058	0.1982	0.4130
6	0.3210	0.4725	0.3427	0.4750	0.4712	0.3784	0.2317	0.2322	0.2322	0.2328	0.4577
7	0.5033	0.4904	0.4012	0.5138	0.5286	0.4672	0.2298	0.2192	0.2192	0.2086	0.4450

As mentioned earlier, because loads in EMS and planning powerflow cases are defined at different voltage levels, only changes in the EMS Q/P ratios were utilized. This requires definition of a "starting point" case. The LDC Step1 case was defined as such starting point by assuming its Q/P ratios to be the same as in the PSS/E peak load case provided by NYISO (*s08pktr6_060908_2_2_clay_conEd_ABB.sav*). For the remaining LD2 through LD7 cases, the reactive power scaling for each zone was based on the relative Q/P ratio (QP_{Relative} defined in Equation 4.1) between the Q/P ratio at that LDC step and that at LDC step1 as shown in Table 4.3. The equation for relative Q/P ratio is:

$$(QP_{\mathrm{Relative}})_{mn} = \frac{(Q/P)_{mn}}{(Q/P)_{1n}} \tag{4.1}$$

Where, *m* denotes LDC steps (2~7), and *n* denotes zones (1~11).

Table 4.3: Relative Load Q/P Ratio in each Zone for each LDC Step

(With respect to LDC Step1)

Step	A	B	C	D	E	F	G	H	I	J	K	Total
1	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
2	0.9415	1.1342	0.9361	0.9330	0.9641	0.9310	0.8943	0.8713	0.8713	0.8467	1.0440	0.9306
3	0.7631	1.2036	0.8221	0.9379	0.9095	0.8714	0.7229	0.7409	0.7409	0.7602	1.1536	0.8637
4	0.8220	1.2772	0.8470	0.9785	0.9699	0.8928	0.7522	0.7473	0.7473	0.7421	1.2416	0.9040
5	0.8905	1.3372	0.9271	0.9855	1.0851	0.9522	0.7759	0.7739	0.7739	0.7718	1.4992	0.9730
6	0.8877	1.6589	0.9880	1.0041	1.2305	0.9859	0.8421	0.8732	0.8732	0.9065	1.6616	1.1023
7	1.3919	1.7216	1.1568	1.0860	1.3804	1.2174	0.8352	0.8242	0.8242	0.8124	1.6156	1.2482

Assuming the load at LDC step *m* in zone *n* is: P_{mn} (Table 3.9), Q_{mn} (*m* =1~7, *n* = 1~11). Then the reactive load for each bus in each zone is calculated as in Equation 4.2:

$$Q_{mn} = Q_{1n} * (QP_{\mathrm{Relative}})_{mn} * \frac{P_{mn}}{P_{1n}} (m = 2 \sim 7) \tag{4.2}$$

Where, $(QP_{\mathrm{Re}lative})_{mn}$ is the relative load Q/P ratio at LDC step *m* for zone *n* as listed in Table 4.3.

Table 4.4: Reactive Power Load Scaling by zone for LDC steps

Step	A	B	C	D	E	F	G	H	I	J	K	Total
1	1099	763	1332	306	518	877	694	286	676	5321	1890	13762
2	879	736	1060	243	425	694	528	212	501	3830	1677	10783
3	629	689	821	215	354	573	376	159	376	3034	1635	8861
4	587	634	733	195	327	509	340	139	328	2567	1525	7883
5	567	592	716	175	326	484	313	128	303	2382	1644	7631
6	465	604	628	147	304	412	279	119	282	2301	1498	7039
7	606	520	610	132	283	423	230	93	221	1712	1209	6038

The resulting power factors in each zone for each LDC step are shown in Table 4.5.

Table 4.5 Power Factor in each Zone for each LDC step

Step	A	B	C	D	E	F	G	H	I	J	K	Total
1	0.927	0.933	0.912	0.939	0.935	0.934	0.959	0.905	0.905	0.904	0.944	0.924
2	0.939	0.915	0.924	0.956	0.942	0.942	0.965	0.920	0.921	0.930	0.934	0.934
3	0.962	0.905	0.943	0.964	0.951	0.949	0.975	0.938	0.937	0.942	0.916	0.942
4	0.962	0.902	0.948	0.971	0.951	0.949	0.971	0.935	0.930	0.940	0.890	0.939
5	0.958	0.895	0.941	0.976	0.941	0.942	0.970	0.925	0.923	0.935	0.843	0.930
6	0.961	0.850	0.939	0.981	0.925	0.937	0.964	0.898	0.898	0.910	0.806	0.914
7	0.915	0.840	0.921	0.982	0.903	0.906	0.964	0.885	0.903	0.927	0.806	0.909

4.3 NON-CONFORMING LOADS (NON-SCALABLE)

NYISO provided information on a few non-confirming loads. They are located at the following buses:

- Reynolds: #148018, #148019, #148020
- GM-CFD: #148017
- Alcoa: #148015

The load profile of these facilities is relatively constant throughout the year. They amount to a total 448.59 MW + j147.45MVars and are all located in Zone D (North). Hence active and reactive power scaling in that zone was modified so as to maintain loads at these buses constant, while, at the same time, complying with the zonal totals listed in Tables 3.9 and 4.4, respectively.

5 SELECTION OF EMS CASES

As mentioned in Section 4, EMS-derived powerflow cases were utilized in helping determine the reactive part of loads for the seven load step cases. They were also utilized as a reference in determining representative unit commitments for each of the cases. This section summarizes the criteria upon which those EMS cases were selected. Such selection was based on PI hourly load data provided by the NYISO for the last three years.

Based on such data, the hourly load profiles for each of the past three years are drawn in Figures 5.1 through 5.3. Taking into consideration the twin objectives of determining load power factors and generator unit commitments, the load profiles suggest the following three periods of interest: Summer Peak, Winter Peak, and Spring Trough. The Summer Peak condition is likely representative of significant penetration of air conditioning loads, as well as of maximum generation dispatch (and thus unit commitment) levels. Winter Peak conditions on the other hand could help characterize the impact of heating loads on power factors, and can also help characterize conditions with medium to high unit commitment. The lowest loads throughout the year are observed during the Spring Trough, and thus the period could be representative of a time for reduced unit commitment due to maintenance. Further, from observation of Figures 5.1 through 5.3 the following specific conditions were chosen as more representative of these three periods:

- Summer Peak: July 2007 to August 2007
- Winter Peak: December 2007 to February 2008
- Spring Trough: April 2006 to May 2006

For each of the three periods, the load profile for one typical week is shown in Figures 5.4 to 5.6, respectively. The figures suggest overall lower load levels during weekends than on weekdays. The nature of the load is also likely different during the workweek than on weekends. Hence, it appears wise to select samples of each.

The LDC step 1 (100%) is a special case; a snapshot of peak load conditions for each of the three years was recommended. For each of the six other steps, six (6) snapshots each were suggested; three loading conditions (Summer Peak, Winter Peak, and Spring Trough) times two, (weekdays and weekends) each.

However, not all of such data are available. For example, no load during the Summer Peak period can fall into the LDC Step 7 (39.6%) level. Similarly, the LDC Step 2 (85%) can only be captured during Summer Peak conditions. Consequently, the above guidelines were modified so as to reflect such constraints. Our recommendations are summarized in Table 5.1. It should be noted that, whenever possible, for each period at least one weekday and one weekend day were chosen, respectively.

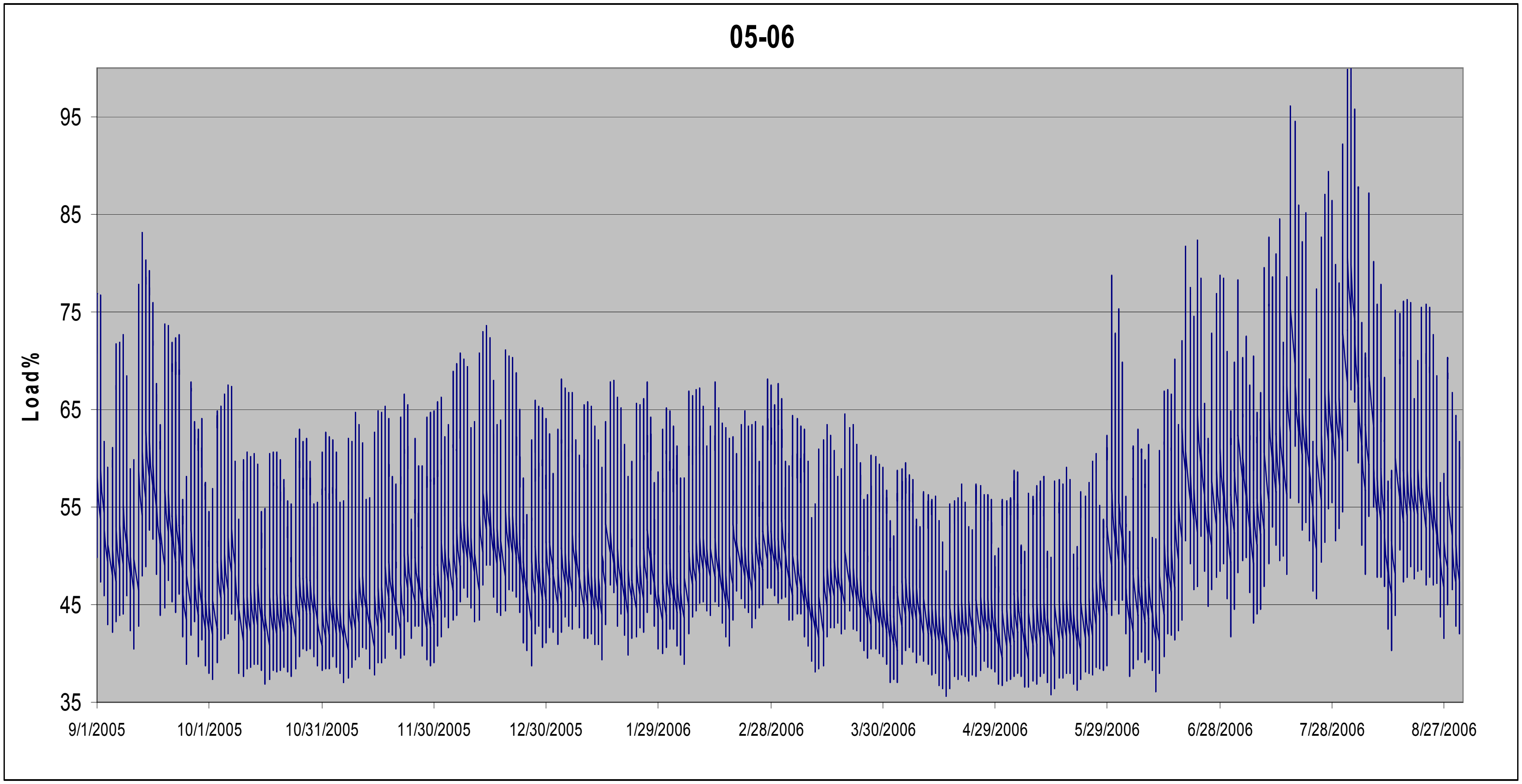


Figure 5.1: Hourly load profile from September 1, 2005 to August 31, 2006

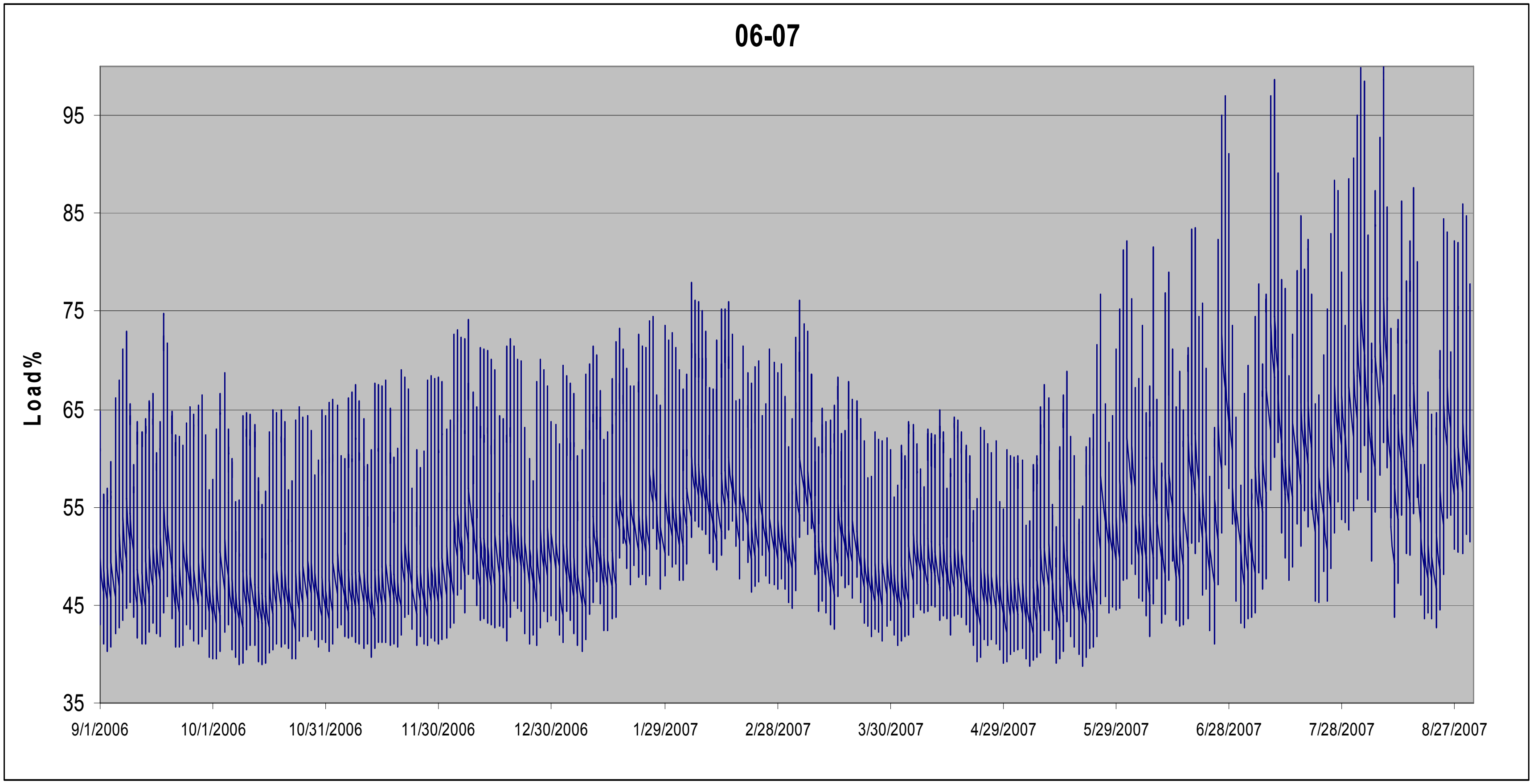


Figure 5.2: Hourly load profile from September 1, 2006 to August 31, 2007

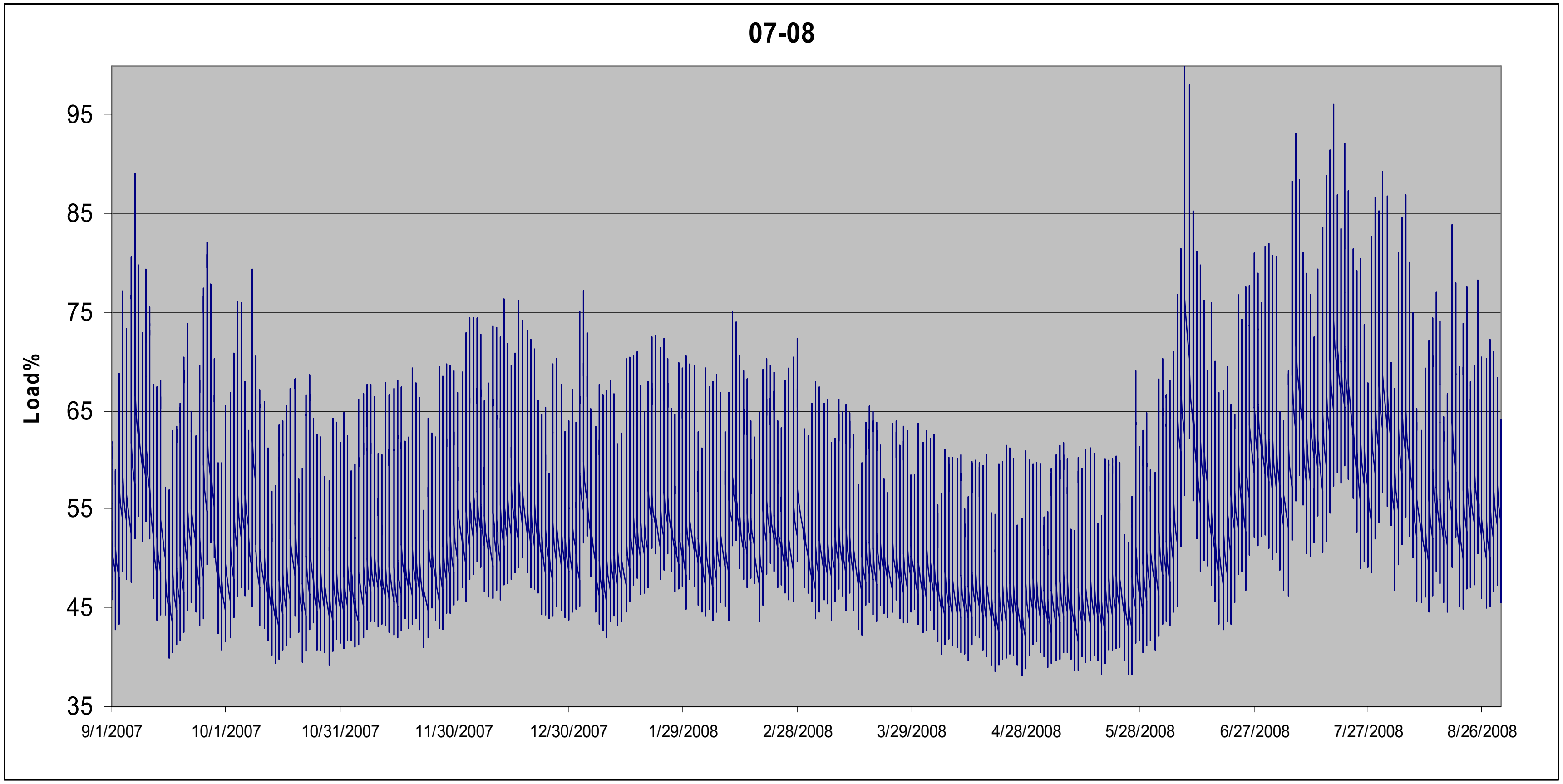


Figure 5.3: Hourly load profile from September 1, 2007 to August 31,2008

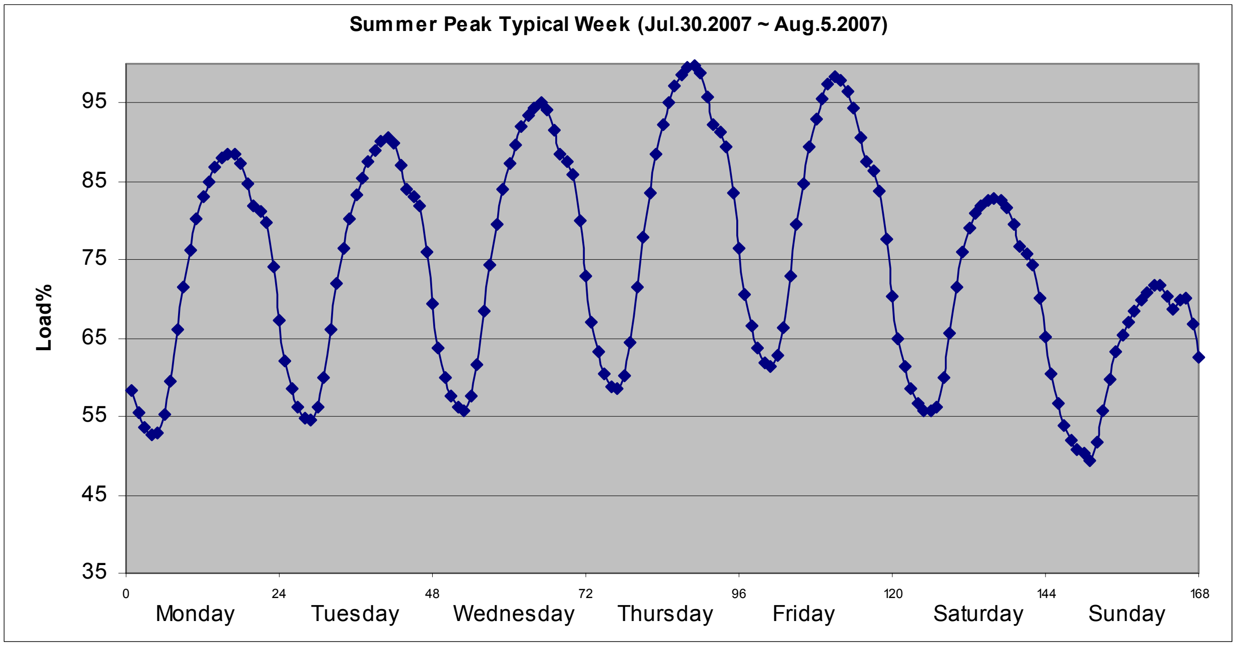


Figure 5.4 Hourly load profile for the week of July 30, 2007 to August 5, 2007

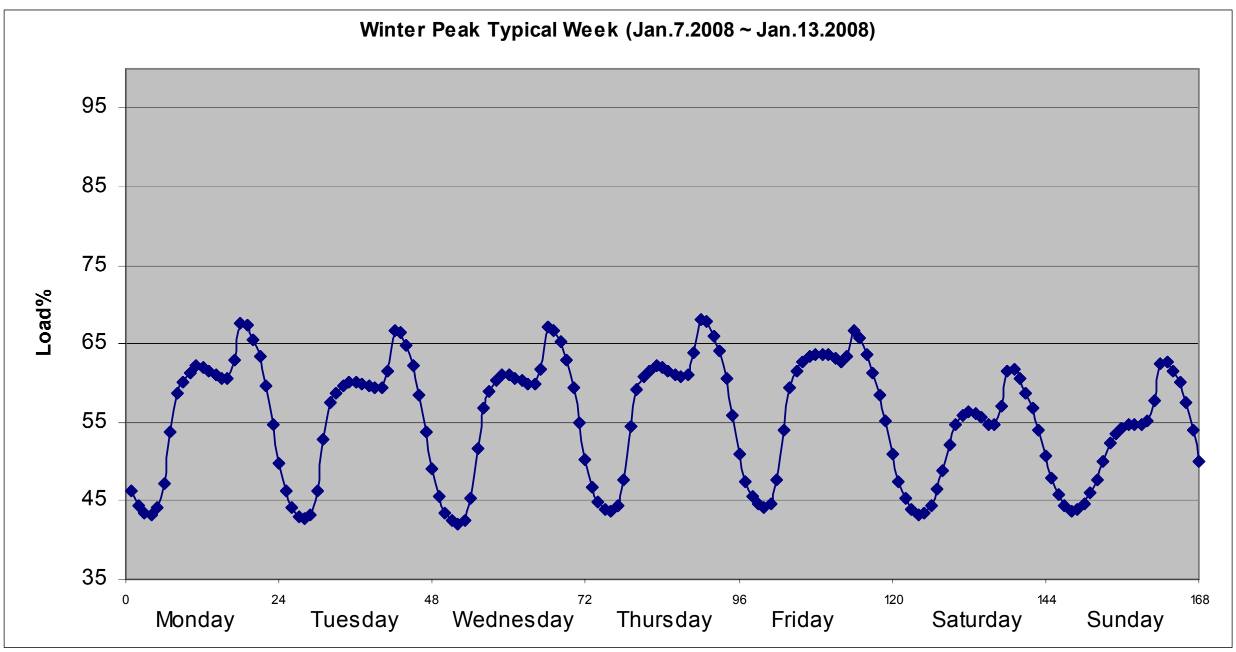


Figure 5.5: Hourly load profile for the week of January 7, 2008 to January 13, 2008

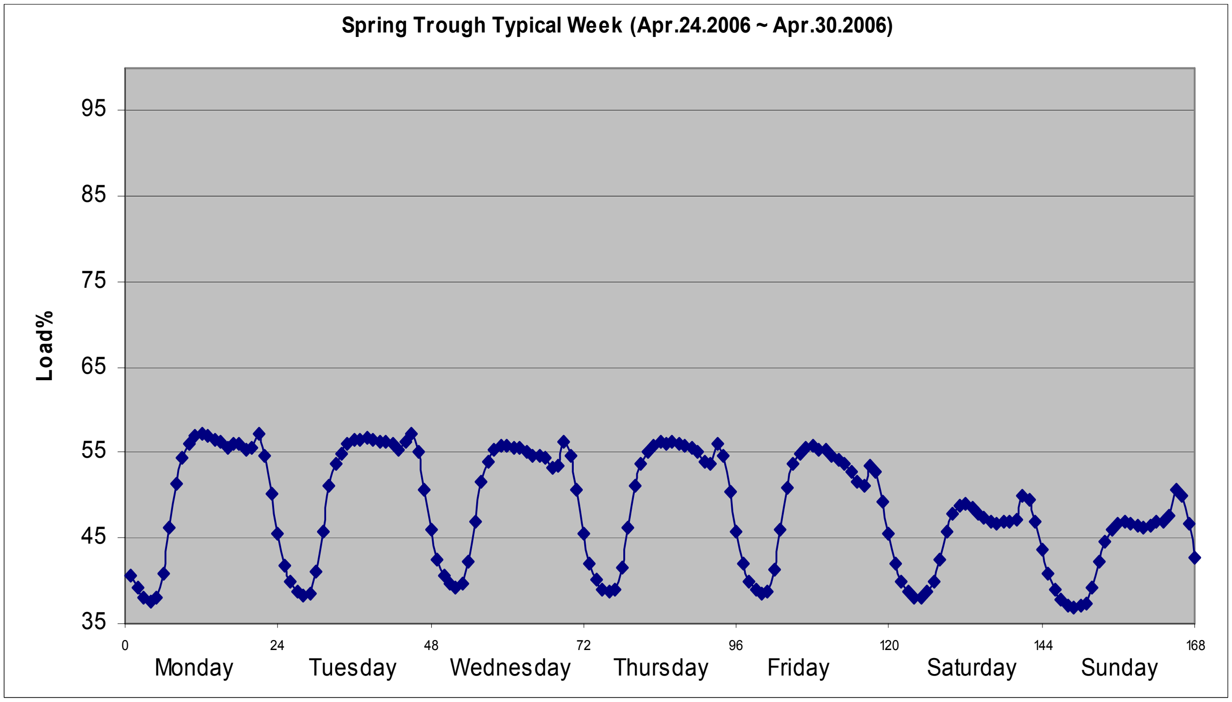


Figure 5.6: Hourly load profile for the week of April 24, 2006 to April 30, 2006

Table 5.1: Requested EMS snapshots

No.	LDC Step	Step%	Date	year	month	day	hour	Total Load	Actual Load %	WeekDay
Summer Peak										
1	1	100.0	6/9/2008	2008	6	9	16	32432	100.00	Monday
2	1	100.0	8/8/2007	2007	8	8	16	32169	100.00	Wednesday
3	1	100.0	8/2/2006	2006	8	2	13	33934	100.00	Wednesday
4	2	85.0	7/19/2008	2008	7	19	16	27640	85.23	Saturday
5	2	85.0	8/16/2007	2007	8	16	14	27304	84.88	Thursday
6	2	85.0	8/7/2006	2006	8	7	13	28977	85.39	Monday
7	3	75.0	7/8/2007	2007	7	8	15	24132	75.02	Sunday
8	3	75.0	8/28/2007	2007	8	28	10	24236	75.34	Tuesday
9	3	75.0	7/11/2008	2008	7	11	18	24468	75.44	Friday
10	4	65.0	7/21/2007	2007	7	21	13	20920	65.03	Saturday
11	4	65.0	8/7/2007	2007	8	7	0	20957	65.15	Tuesday
12	5	58.0	7/9/2007	2007	7	9	5	18847	58.59	Monday
13	5	58.0	8/18/2007	2007	8	18	13	18836	58.55	Saturday
14	6	47.7	7/14/2007	2007	7	14	5	15312	47.60	Saturday
15	6	47.7	8/21/2007	2007	8	21	0	15368	47.77	Tuesday
Winter Peak										
16	3	75.0	12/13/2007	2007	12	13	18	24421	75.30	Thursday
17	3	75.0	1/2/2008	2008	1	2	18	24320	74.99	Wednesday
18	3	75.0	2/6/2007	2007	2	6	19	24140	75.04	Tuesday
19	4	65.0	12/9/2007	2007	12	9	20	21109	65.09	Sunday
20	4	65.0	1/23/2008	2008	1	23	13	21087	65.02	Wednesday
21	5	58.0	12/1/2007	2007	12	1	14	18805	57.98	Saturday
22	5	58.0	1/15/2008	2008	1	15	22	18940	58.40	Tuesday
23	6	47.7	12/2/2007	2007	12	2	5	15490	47.76	Sunday
24	6	47.7	1/18/2008	2008	1	18	1	15562	47.98	Friday
Spring Trough										
25	5	58.0	5/4/2006	2006	5	4	12	19673	57.97	Thursday
26	5	58.0	4/15/2007	2007	4	15	13	18774	58.36	Sunday
27	6	47.7	5/20/2006	2006	5	20	9	16189	47.71	Saturday
28	6	47.7	4/10/2006	2006	4	10	6	16091	47.42	Monday
29	7	39.6	5/28/2006	2006	5	28	3	13391	39.46	Sunday
30	7	39.6	4/21/2006	2006	4	21	1	13438	39.60	Friday
31	7	39.6	4/30/2007	2007	4	30	2	12730	39.57	Monday
Others										
32	4	65.0	10/3/2006	2006	10	3	18	20912	65.01	Tuesday
33	4	65.0	11/3/2006	2006	11	3	17	21028	65.37	Friday

6 INTERFACE FLOWS, IMPORTS & EXPORTS

In Sections 3 and 4 the determination of representative load levels for each of the seven load steps is discussed. Zonal generation levels must be determined too. To aid in such determination, the NYISO provided interface flows, including imports and exports, for each hour of an 8760-hour period in the year of 2007~2008. The average value in each step was used as the desired interface flow.

Table 6.1: Average MW Interface Flow during the Year of 2007~2008

Step	1	2	3	4	5	6	7
DYSINGER-EAST	1867	1968	1860	1790	1838	1625	1481
WEST-CENTRAL	752	1021	1115	1209	1334	1307	1091
MOSES-SOUTH	1807	1782	1378	1049	877	421	440
CENTRAL-EAST	2135	1967	1917	1842	1819	1787	1831
TOTAL-EAST	2822	3088	3476	3740	3666	3594	3225
UPNY-CONED	2785	2531	2516	2420	2007	1110	500
DUNWOODIE-SOUTH	2597	2639	2733	2780	2448	1902	1537
HYDRO-QUEBEC	1381	1378	1069	848	588	29	-118
ISO NE-NYISO	455	576	430	199	-3	-461	-448
IMO-NYISO	205	336	296	202	593	1058	1223
PJM-NYISO	-837	-131	348	834	819	1045	303
NEPTUNE	445	569	607	600	581	574	632
SHORHAM	328	314	293	273	228	133	11
CONED-LIPA	382	367	488	551	546	423	283

Note:

- PJM-NYISO does not include NEPTUNE
- ISONE-NYISO includes SHOREHAM

However, per NYISO-LIPA's 12/15/2008 comments:

- CSC (SHOREHAM) is always 330 MW
- NEPTUNE is always 660 MW except at Peak when PJM may not be able to provide the full 660 and in cases 6 and 7 with very low load levels

Thus, the desired interface flows were adjusted as follows:

Table 6.2: Adjusted MW Interface Flow during the Year of 2007~2008

Step	1	2	3	4	5	6	7
DYSINGER-EAST	1867	1968	1860	1790	1838	1625	1481
WEST-CENTRAL	752	1021	1115	1209	1334	1307	1091
MOSES-SOUTH	1807	1782	1378	1049	877	421	440
CENTRAL-EAST	2135	1967	1917	1842	1819	1787	1831
TOTAL-EAST	2822	3088	3476	3740	3666	3594	3225
UPNY-CONED	2785	2531	2516	2420	2007	1110	500
DUNWOODIE-SOUTH	2597	2639	2733	2780	2448	1902	1537
HYDRO-QUEBEC	1381	1378	1069	848	588	29	-118
ISO NE-NYISO	455	576	430	199	-3	-461	-448
IMO-NYISO	205	336	296	202	593	1058	1223
PJM-NYISO	-837	-131	348	834	819	1045	303
NEPTUNE	250	660	660	660	660	550	450
SHORHAM	330	330	330	330	330	330	330
CONED-LIPA	382	367	488	551	546	423	283

7 GENERATION DISPATCH AND UNIT COMMITMENT

7.1 GENERATOR DISPATCH

The next step in the derivation of the seven load step powerflows was to define a load – generation balance. NYISO provided ABB with zonal generation levels, for each hour of an 8760-hour period in the year of 2007~2008. The average value of generation in each zone is summarized in Table 7.1.

Table 7.1: Average generation in each zone for each step

Step	1	2	3	4	5	6	7
A	4054	3863	3596	3416	2955	2125	1704
B	658	626	664	690	615	616	372
C	4541	3593	3573	3354	3027	2897	2914
D	1359	1248	1174	1101	1088	1033	1141
E	408	361	347	403	403	394	402
F	2610	2331	2072	1784	1471	764	239
G	1972	1084	685	503	422	370	228
H	2086	2083	2089	2043	1964	1981	1932
I	0	0	0	0	0	0	0
J	6932	5822	4585	3064	2498	1965	1543
K	3717	2951	2185	1405	1100	821	653
TOTAL	28335	23962	20970	17764	15543	12968	11127

The above generation levels were per-unitized on the basis of zonal generation levels for the peak load case.

Table 7.2: Generation ratio by zone for each step

Step	1	2	3	4	5	6	7
A	1.000	0.953	0.887	0.843	0.729	0.524	0.420
B	1.000	0.951	1.009	1.048	0.935	0.936	0.565
C	1.000	0.791	0.787	0.739	0.667	0.638	0.642
D	1.000	0.918	0.864	0.810	0.801	0.760	0.839
E	1.000	0.887	0.851	0.988	0.988	0.968	0.985
F	1.000	0.893	0.794	0.684	0.564	0.293	0.092
G	1.000	0.550	0.347	0.255	0.214	0.188	0.116
H	1.000	0.999	1.002	0.980	0.942	0.950	0.926
I	1.000	1.000	1.000	1.000	1.000	1.000	1.000
J	1.000	0.840	0.662	0.442	0.360	0.283	0.223
K	1.000	0.794	0.588	0.378	0.296	0.221	0.176

As mentioned earlier, each of the seven load step cases were derived on the basis of a 2008 peak load case provided by the NYISO. That powerflow case has a total NYISO load of 31,639

MW. A NYISO load of 33,200 MW was assumed when modeling the peak case LD1 step. Hence, in developing the LD1 case, a 1.049 factor (33,200/31,639) was assumed throughout the NYISO system.

Further, the previously mentioned statistical analysis of one years' worth of generation indicated a peak load generation of 28,335 MW, whereas the 2008 peak load case provided displays a total generation of 31,156 MW. Hence, an additional ratio of 1.099 was utilized (31,156/28,335).

On the basis of the above two ratios (1.049 and 1.099), as well as ratios between the peak load and the remaining six load steps listed in Table 7.2, the desired generation levels in Table 7.3 were derived.

Table 7.3: Desired Generation in each Zone for each Load Step

Step	1	2	3	4	5	6	7
A	4677	4480	4205	4087	3606	2556	1983
B	759	725	776	825	750	741	432
C	5240	4167	4178	4013	3693	3484	3390
D	1568	1447	1373	1317	1328	1242	1327
E	470	419	406	482	491	474	467
F	3011	2704	2423	2135	1795	919	278
G	2275	1258	801	601	515	445	266
H	2407	2415	2443	2444	2396	2383	2249
I	0	0	0	0	0	0	0
J	7998	6752	5362	3666	3047	2363	1795
K	4289	3423	2554	1681	1342	988	760
TOTAL	32694	27790	24521	21251	18963	15595	12947

7.2 UNIT COMMITMENT

In addition to scaling the generation levels in the original 2008 summer peak case as described in Table 7.3, it was recognized that at lower load levels less units were likely to be committed. Hence, on the basis of information provided by the NYISO regarding base-loaded units (e.g., coal-fired and nuclear units), peaking units (e.g. simple-cycle combustion turbines), older, less economical units, and other units not falling in these categories, such as hydro plants, combined-cycle units and the pumped storage units at the Gilboa plant, a priority-ordered, zone-based unit commitment was derived.

8 OPTIMAL POWER FLOW (OPF) SETUP

8.1 INTRODUCTION

As previously discussed, on the basis of a 2008 peak load powerflow provided by the NYISO, seven "load step" cases were derived. In the following previous section particular attributes of such seven cases have been discussed:

- Section 3 – Active Power Loads
- Section 4 – Reactive Power Loads
- Section 6 – Desired Interface Flows
- Section 7 – Desired Generation Levels and Unit Commitment

Thus, the next step was to incorporate all of the above information into seven distinct powerflows representing each of the respective load steps.

Due to the magnitude of the NYISO system, doing so with a conventional powerflow is a time-consuming proposition. For example, compliance with voltage criteria might require the manual setting of large numbers of generation scheduled voltages, of transformer taps, and of switched capacitors and reactors. Further, as indicated in the projects' scope of work, use of Optimal Power Flow techniques is expected to be at the core of the loss minimization analyses, and this requires that the base cases be derived with similar techniques, so as to avoid comparing "apples with oranges".

Hence, the Optimal Power Flow techniques in PSS/E's OPF were employed in deriving the seven powerflow cases.

OPF analyses require definition of three elements:

a) The Objective function.

b) Constraints

c) Control variables to activate in minimizing the objective function subject to the constraints

In deriving each of the seven base cases the following problem formulation was employed:

- Because in rare occasions some voltage constraints cannot be met with the control variables made available to OPF, the program was allowed to add shunt compensation, but to minimize its deployment. That was the Objective Function.
- In addition to hardware constraints (such as reactive limits on generators and tap limits on transformers) the most critical constraint modeled was bus voltage limitations (see below).
- Generator voltages, transformer taps and switched shunts (the latter adjusted manually on the basis of OPF recommendations) were the control variables used to minimize the addition of additional shunt compensation subject to the constraints.

8.2 VOLTAGE CONSTRAINTS

Bus voltages limits outside NYCA were set to a wide 0.8 to 1.2 pu range. Because outside the NYCA taps, generator voltages and switched shunts were frozen at the levels in the 2008 peak load base case, voltages outside NYCA remained close to those in such base case (except for minor changes made to reduce very large deviations (e.g., below 0.9 and in excess of 1.15 pu). Within the NYCA, on the other hand, the following range limits were applied per NYISO Transmission Planning Criteria.

Nominal Voltage	Pre-contingency Low	Pre-contingency High
230 kV and up	0.98 p.u.	1.05 p.u.
115 kV and below	0.95 p.u.	1.05 p.u.

CONED requires that both of their pre- and post- contingency voltages lie within the range of 0.95 to 1.05 p.u. Since the current version of OPF can only consider one system condition at a time, special, more stringent limits were set for the CONED system:

Nominal Voltage	Pre-contingency Low	Pre-contingency High
230 kV and up	1.02 p.u.	1.05 p.u.
138 kV and below	1.00 p.u.	1.05 p.u.

Moreover, CONED has some “voltage envelope” requirements at specific station voltages. They were also taken into account during the OPF runs and they are case (i.e., LD1 through LD7) specific.

In addition several 138, 230 kV, and 345 kV buses were identified by NYISO for special range limits. These are listed in Table 8.1.

Table 8.1: Specific Voltage Criteria for Selected Buses

Bus Name	Base kV	Pre Low	Pre High	Pre Low PU	Pre High PU
Northport 138	138	135	145	0.978261	1.050725
Watercure 230	230	215	242	0.934783	1.052174
Gardenville 230	230	217	242	0.943478	1.052174
Niagara 230	230	225	242	0.978261	1.052174
St Lawrence 230	230	225	242	0.978261	1.052174
Oakdale 345	345	336	362	0.973913	1.049275
Coopers Corners 345	345	338	362	0.979710	1.049275
Farragut 345	345	338	362	0.979710	1.049275
Fraser 345	345	338	362	0.979710	1.049275
Goethals 345	345	338	362	0.979710	1.049275
Gowanus 345	345	338	362	0.979710	1.049275
Millwood 345	345	338	362	0.979710	1.049275
Niagara 345	345	338	362	0.979710	1.049275
Rainey 345	345	338	362	0.979710	1.049275
Somerset 345	345	338	362	0.979710	1.049275
Pannell Road 345	345	341	359	0.988406	1.040580
Station 80 345	345	343	359	0.994203	1.040580
Pleasant Valley 345	345	343	362	0.994203	1.049275

Bus Name	Base kV	Pre Low	Pre High	Pre Low PU	Pre High PU
Bowline 345	345	345	362	1.000000	1.049275
Clay 345	345	345	362	1.000000	1.049275
Leeds 345	345	345	362	1.000000	1.049275
Roseton 345	345	345	362	1.000000	1.049275
Buchanan 345	345	346	362	1.002899	1.049275
Dunwoodie 345	345	346	362	1.002899	1.049275
Ladentown 345	345	346	362	1.002899	1.049275
Ramapo 345	345	346	362	1.002899	1.049275
Sprainbrook 345	345	346	362	1.002899	1.049275
Edic 345	345	347	362	1.005797	1.049275
Gilboa 345	345	348	362	1.008696	1.049275
Marcy 345	345	348	362	1.008696	1.049275
New Scotland 345	345	348	362	1.008696	1.049275
Rock Tavern 345	345	348	362	1.008696	1.049275
Ramapo 500	500	500	550	1.000000	1.100000

8.3 OTHER CONSTRAINTS

8.3.1 Swing bus

The Eastern Interconnection swing bus was switched from #364003 1BR Ferry N3 to #147750 Niagara Unit 1. This change recognizes the fact that the dominant flow in NY areas is from West to East.

8.3.2 Load Conversion

In the PSS/E case from NYISO, the loads at zones I, J, K include constant current and constant impedance components. The concern with such representations is that in order to minimize losses, the OPF may attempt to change bus voltages at those buses in order to alter their respective active or reactive power consumption. This effect may be investigated as a sensitivity in the loss analysis studies, but, for the core of the analyses, and, consequently, in developing the base cases, such loads were converted to constant power load instead.

8.3.3 Generator Reactive Capability

The ability of generation to rapidly increase (or decrease) reactive output following contingencies is the cornerstone of system reactive performance. Hence it is of interest to preserve as much as possible the reactive capability of such generation for when such contingencies occur.

Consequently, during development of the seven powerflow base cases, the capacitive reactive output of NYISO generation was temporarily limited to either the generator maximum reactive capability, or 0.98 p.f.; whichever was less. It must be noted, however, that such 0.98 p.f. is based on the MVA base of the respective units. In other words, $Q_{MAX} = \min(Q_{MAX}, M_{BASE}*0.2)$

On the inductive side (Q_{MIN}), under system intact conditions generators are normally prevented from absorbing Mvars, both in order to prepare them for contingencies leading to overvoltages, and also because Mvar absorption tends to reduce their internal voltage, and, consequently, their electromechanical stability. Thus, during the OPF solutions, the minimum reactive capability of NYISO generators was temporarily set to zero.

Following the OPF solution the original reactive capability of generators was restored.

8.3.4 FACTS Devices

For reasons similar to those of generators, the output of the Fraser and Leeds SVCs, and the output of the Marcy STATCOM were zeroed-out during the OPF solutions (but restored afterwards).

9 DESCRIPTION OF LD1 THROUGH LD7 BASE CASES

9.1 INTRODUCTION

On the basis of:

- The 2008 *s08pktr6_060908_2_2_clay_conEd_ABB.sav* peak load base case provided to ABB.
- The discussions in Sections 3, 4, 6 and 7 on Active Power Loads, Reactive Power Loads, Interface Flows and Generation Levels and Unit Commitment, respectively.
- The OPF Setup described in Section 8.
- The following input from CONED, RG&E and LIPA:

  RG&E:

  For each load level, RG&E provided a more in-depth representation for the Canandaigua Fingerlakes, Lakeshore and Genesee Valley districts, including branches, loads, switched capacitors and transformer tap range.

  LIPA:

  LIPA provided 4 command files: one for rating changes, one for impedance changes, one to remove the Gershow 69 kV Substation, and one to update the Northport Norwalk Harbor Connection (NNC) formally NUSCO. These changes were common to all seven cases.

  LIPA also provided a spreadsheet with the generation dispatch and commitment for each of the seven cases, including the following aspects:

  - All IPPs are dispatched in all the cases.
  - The Cross-Sound Cable always dispatched at 330 MW.
  - Neptune always dispatched at 660 MW except during the peak load condition when PJM may not be able to provide the full 660 MW and in Cases LD6 and LD7 with very low load levels.

  CONED:

  CONED provided command files to update feeder ratings within their area. Also, for each load level, CONED provided command files to adjust voltage-controlling transformers, switched shunts, bus shunts, and generator scheduled voltage to satisfy “voltage envelope” requirements. Additionally, at some load levels adjustments to phase shifter angles were provided to avoid thermal limit violations.

Seven base-cases describing representative system conditions throughout a typical load cycle were developed. The cases were titled *LD1* through *LD,7* respectively, and are representative of the following load levels:

Table 9.1: Load Duration Steps (100%=33,200 MW)

LDC Step	Upper Range(%)	Lower Range(%)	LDC Step Load(%)	LDC Step Hours
1	100.0	90.0	100.0	48
2	90.0	80.0	85.0	178
3	80.0	70.0	75.0	665
4	70.0	60.0	65.0	1958
5	60.0	52.5	58.0	2633
6	52.5	40.0	47.7	3036
7	40.0	37.5	39.6	242

The purpose of this section is to describe the main attributes of such seven cases.

9.2 ZONAL LOADS, GENERATION AND LOSS LEVELS

Listed in Table 9.2 are load and generation levels as well as active and reactive power losses for each of NYISO's eleven load zones under each of the seven loading conditions. In terms of energy throughout the year, the NYCA active and reactive energy losses are summarized in Table 9.2a.

The assumed peak load level in the LD1 case are 33,200 MW. Load energy throughout the year on the other hand is (from Table 3.9) 167,390 GWHr. Hence, the calculated load demand (capacity) loss of 979 MW is about 2.95% of native load. The load energy loss is 5,727 GWh is 3.42% of the annual load energy.

9.3 INTERFACE FLOWS

Comparison between actual zonal active power generation in Table 9.2 and the desired generation levels listed in Table 7.3 suggest several discrepancies between the two. These discrepancies arise from a combination of generation capacity limitations together with the desire to maintain interface flows as close as possible to the values listed in Table 6.2. Such conflicts and tradeoffs are summarized in Table 9.3 for generation MW output and in Table 9.4 for interface flow levels.

Column 2 in Table 9.3 lists MW generation levels for each NYISO Area (Zone) as in the original base case provided to ABB. The next column lists maximum generation levels per area, as derived from summation of "Pmax" attributes for in-service machines. In the 4th column the desired generation levels listed in Table 7.3 are transcribed. In Column 5 in Table 9.3 actual zonal generation levels as per Table 9.2 are listed. The last column in the table lists the differences between desired and actual generation levels.

Listed in the 2nd column of Table 9.4 are the Interface MW flow levels in the original case provided to ABB. In the column labeled "Desired Flow" the corresponding entries of Table 6.2 are transcribed. Actual interface flows are listed in the next column, and the final column lists the differences between desired and actual flow levels.

Taking the LD1 case as an example, the actual vs. desired differences in generation and interface flow levels stem from the following reasons:

- For Areas 4 (North) and 8 (Millwood), desired generation levels exceeded the maximum generation levels in their respective areas and thus had to be reduced.
- The remaining discrepancies between desired and actual generation levels stem from the additional desire to keep flow levels close to the values derived from historical data.
- Note that whereas historical data indicated an average of 837 MW exports to the PJM system under peak load conditions, in the LD1 case a 211 MW import was modeled instead; not far from the 313 MW imports in the original powerflow case. The reason for this 1048 MW discrepancy can be traced to the higher load levels modeled and the resulting limitations in generation capacity. Note, for example in Table 9.3 that CONED generation is not far from its capacity limit, and so is LIPA generation. UPNY-Coned interface flow levels are already 511 MW higher than the levels suggested from analysis of PI data. Hence it was not deemed possible in this case to furnish the additional 1048 MW flows towards PJM that resulted from PI data analyses.

Table 9.2a – Annual NYCA Active and Reactive Energy Losses

Load Step	Hours	Losses (MW)	Losses (Mvar)	Losses (GWHr)	Losses (GvarHr)
LD1 (90%-100%)	48	979.4	15,760.1	47.0	756.5
LD2 (80%-90%)	178	888.1	13,653.2	158.1	2,430.3
LD3 (70%-80%)	665	809.7	12,319.0	538.5	8,192.1
LD4 (60%-70%)	1958	690.5	10,154.7	1,352.0	19,882.9
LD5 (52.5%-60%)	2633	686.7	9,404.3	1,808.1	24,761.5
LD6 (40%-52.5%)	3036	562.3	7,674.8	1,707.1	23,300.7
LD7 (37.5%-40%)	242	481.8	6,792.3	116.6	1,643.7
Total/Averages	**8760**			5,727.4	80,967.8

9.4 REACTIVE PERFORMANCE

Through a combination of transformer tap, generation voltage, existing switched and bus shunts adjustments as well as some minor additional shunt compensation (all as dictated by the OPF) all seven cases met the prescribed NYISO voltage constraints (Section 8.2), even when generation of reactive power was limited to a maximum of about 20% of the respective units' MVA bases (0.98 pf) and output from the SVCs at Fraser and Leeds and the STATCOM at Marcy was set to zero.

The one exception to this general rule was the LD1 case, where the following additional compensation was necessary in order to meet criteria[4]:

NYC Zone

- 70 Mvar capacitor at Bus 126721 (E63RD#1) (Figure 9.1)
- 70 Mvar capacitor at Bus 126722 (E63RD#2) (Figure 9.2)

Both in the vicinity of the Queensbridge 138 kV/69 kV substation, and for the purpose of load reactive power compensation:

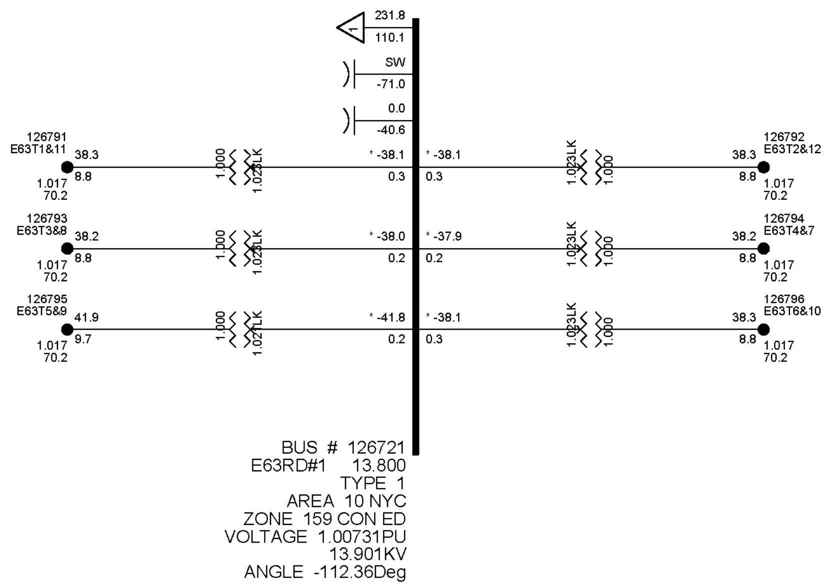


Figure 9.1 – 70 Mvar Capacitor at Bus 126721 (E63RD#1)

Central Zone

- 20 Mvar Capacitor at Meyer 230 kV Station (Bus 130764) (Figure 9.3)

[4] It is worth noting that if reactive limits on generation are relaxed from 0.98 pf to 0.95 pf (i.e., from 20% to 31% of their respective MVA bases), the compensation is no longer necessary.

Capital Zone

- 10 Mvar Capacitor on the 46 kV side of the Barton Brook 115 kV Substation (Bus 131764) (Figure 9.4)
- 10 Mvar Capacitor at 34.5 kV Bus 137630 (NWTN+OAT); vicinity of Latham and Patroons Substations in the Capital District (Figure 9.5).

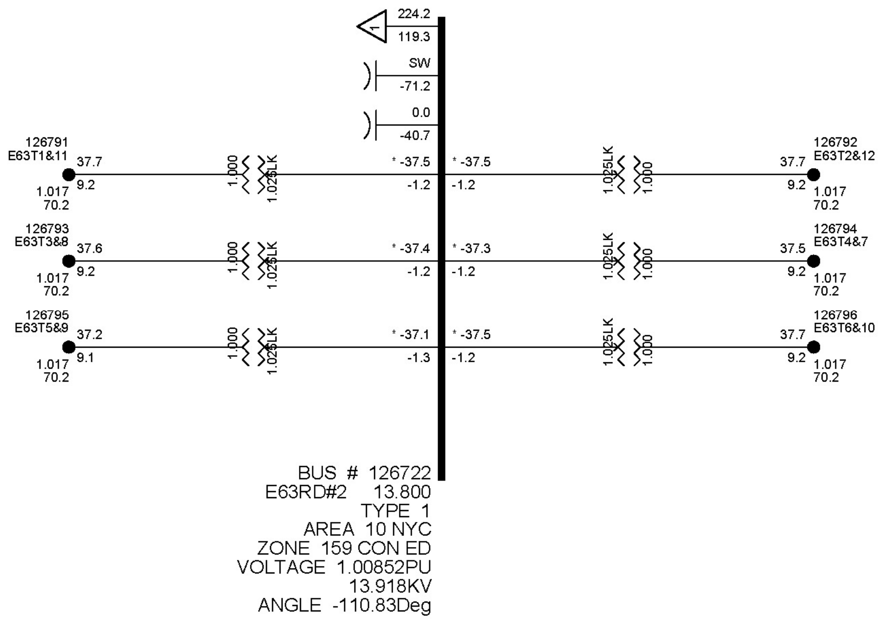


Figure 9.2 – 70 Mvar Capacitor at Bus 126722 (E63RD#2)

Figure 9.3 – 20 Mvar Capacitor at Meyer 230 kV

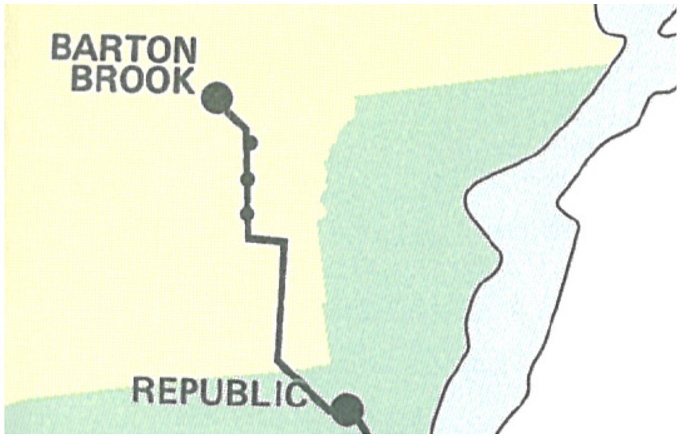


Figure 9.4 – 10 Mvar Capacitor at 46 kV side of Barton Brook

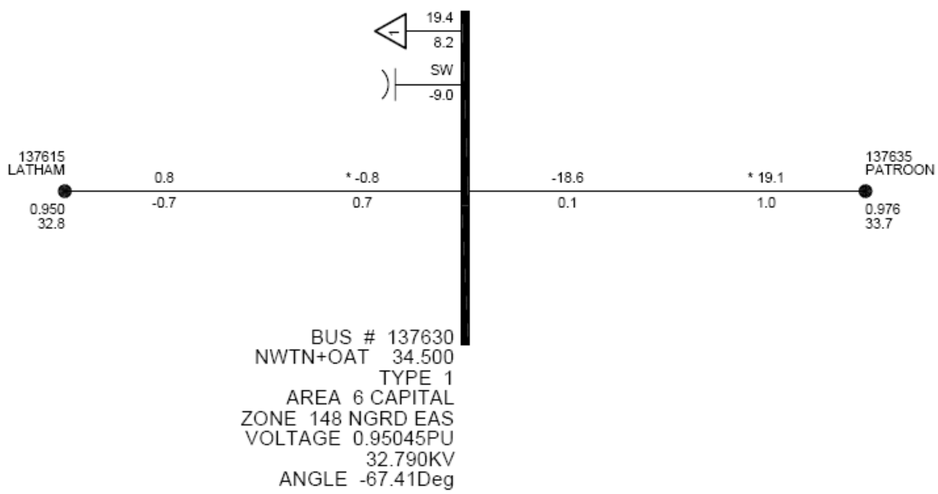


Figure 9.5 – 10 Mvar Capacitor in Capital Region

9.5 VOLTAGE PROFILES

Listed in Table 9.5 are NYCA voltages in excess of 105% and below 95% of nominal suggesting compliance, for the most part, with the established voltage constraints.

Shown in Figure 9.6 is a depiction of the bulk transmission voltage profiles for each of the seven load step cases. The color scale ranges from deep blue for 0.95 voltages to deep red for 1.05 pu voltages. The figures suggest the following areas consistently displaying lower voltages (although in all cases acceptable) across the seven loading conditions:

- Watercure Substation and Vicinity
- Transmission North of the Capital District
- Transmission around (but not including) the Fraser Substation

Finally, shown in Figure 9.7 is the voltage profile for Case *s08pktr6_060908_2_2_clay_conEd_ABB.sav* provided to ABB; depicting peak load conditions in 2008.

Worth noting when comparing against Case LD1 in the previous figure that the two cases are not altogether comparable, in that the original case provided to ABB had a NYCA load level of 31,639 MW. The LD1 Case, on the other hand, has a higher, 33,209 MW NYCA load level.

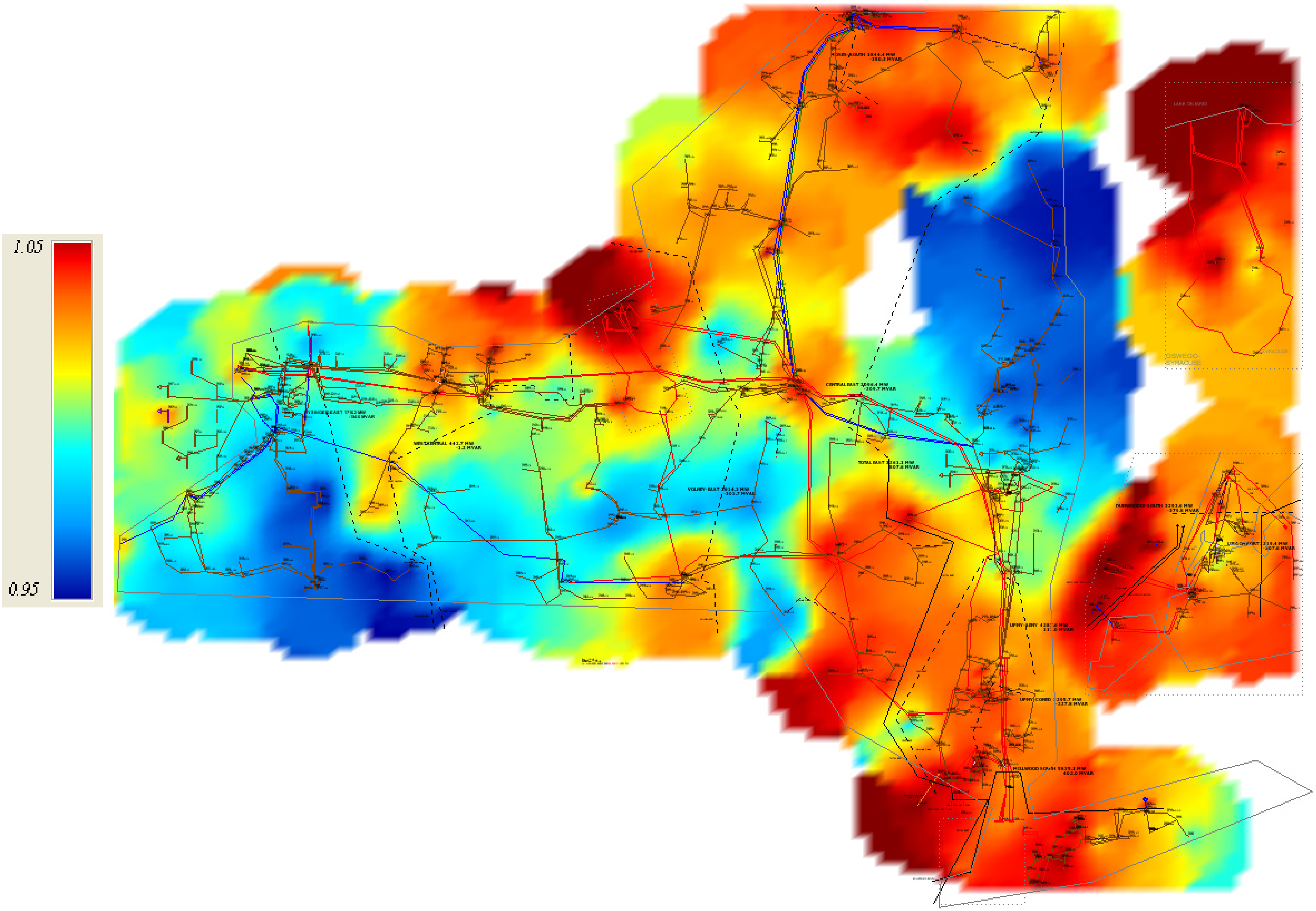


Figure 9.6 – NYCA Voltage Profile - 0.95 pu to 1.05 pu Color Scale – LD1 Case

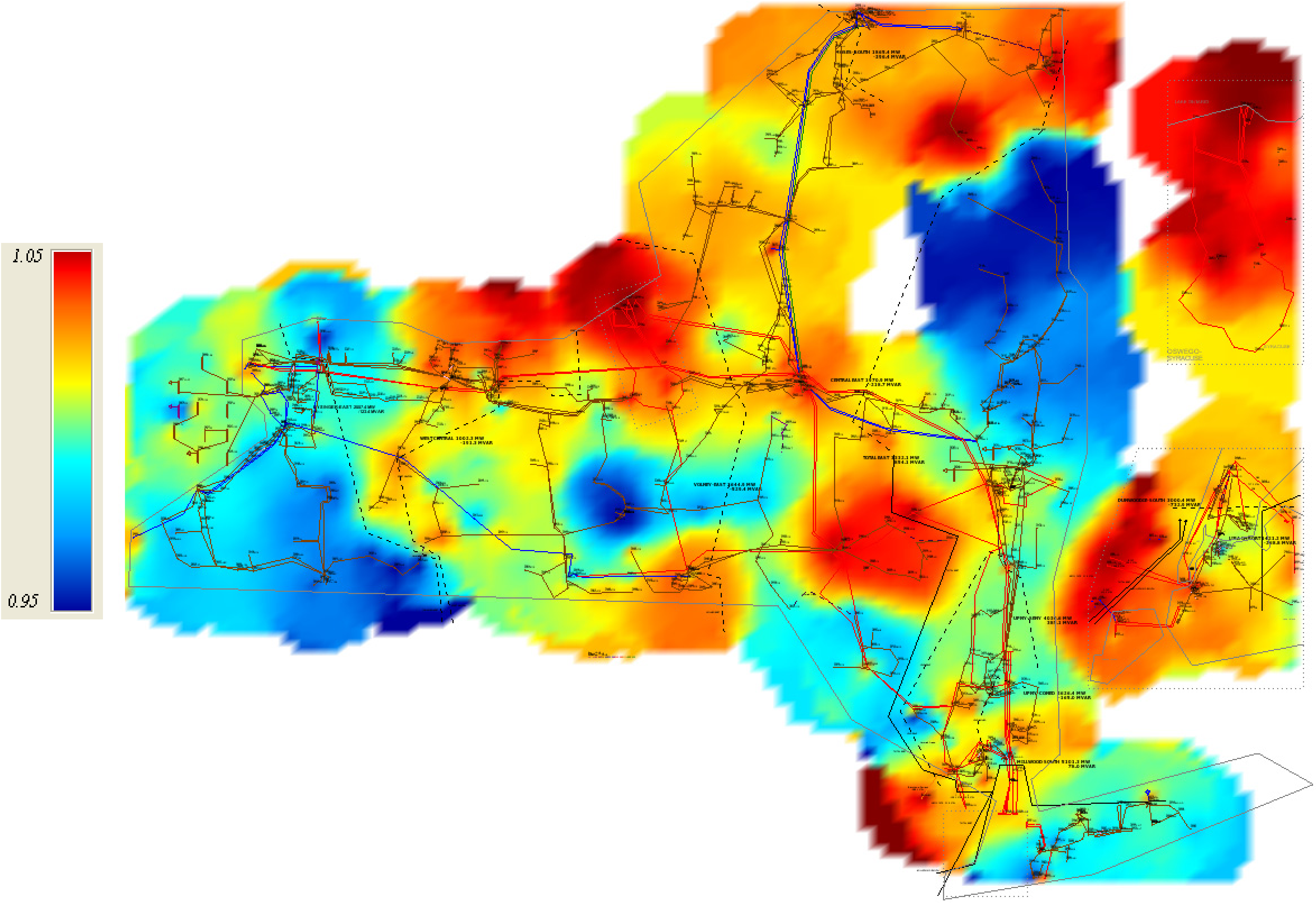


Figure 9.6 (Cont.) - LD2 Case

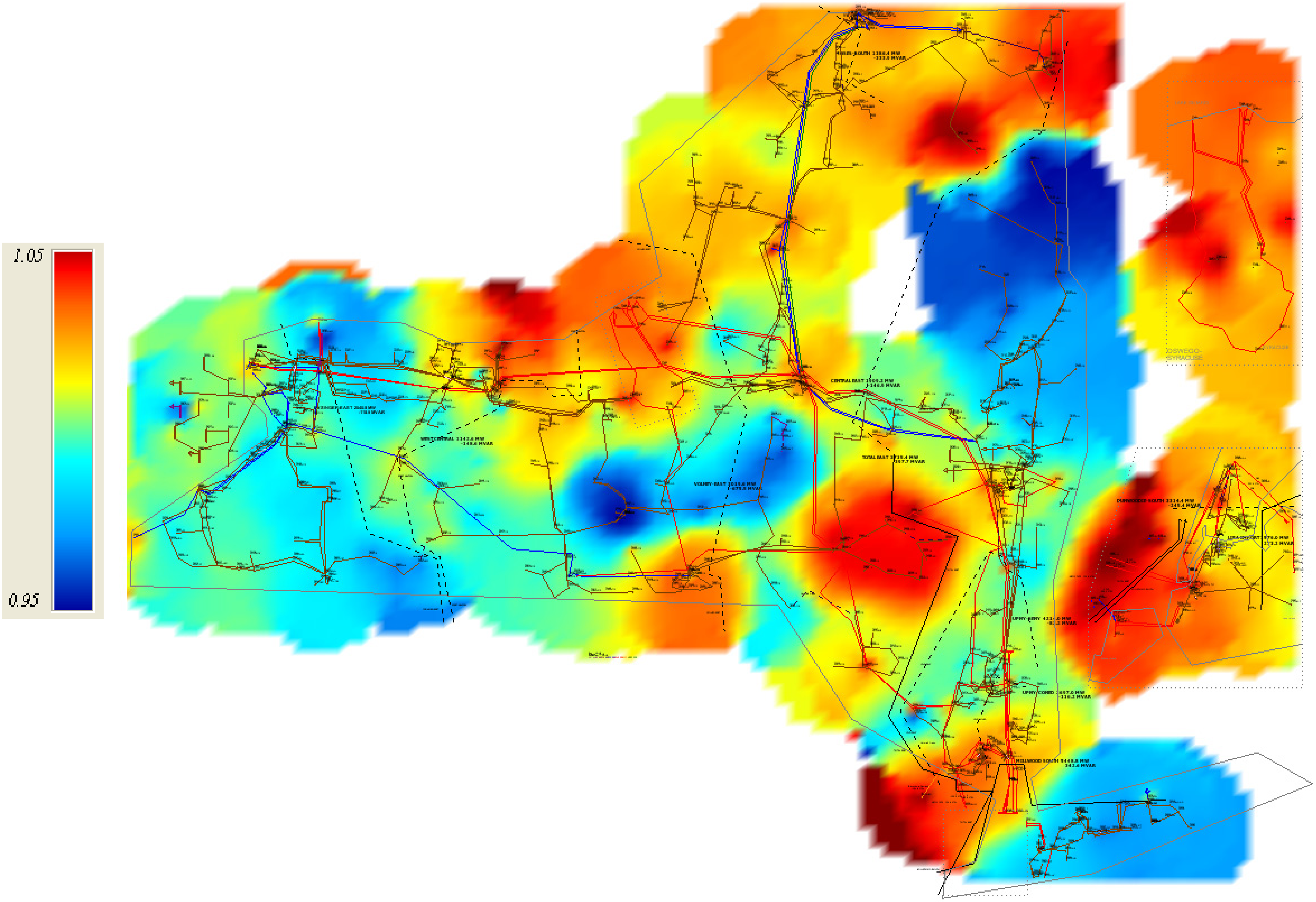


Figure 9.6 (Cont.) - LD3 Case

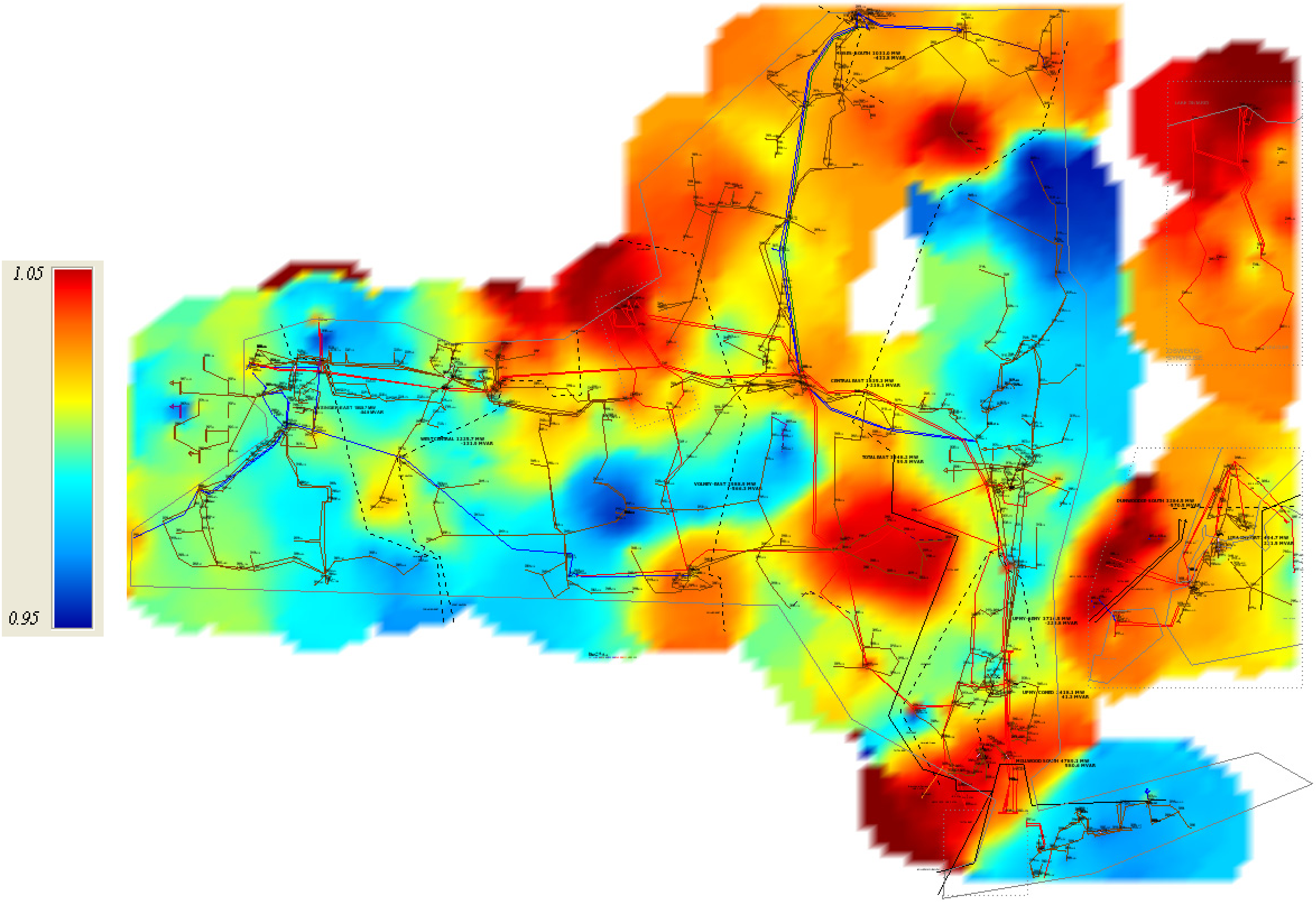


Figure 9.6 (Cont.) - LD4 Case

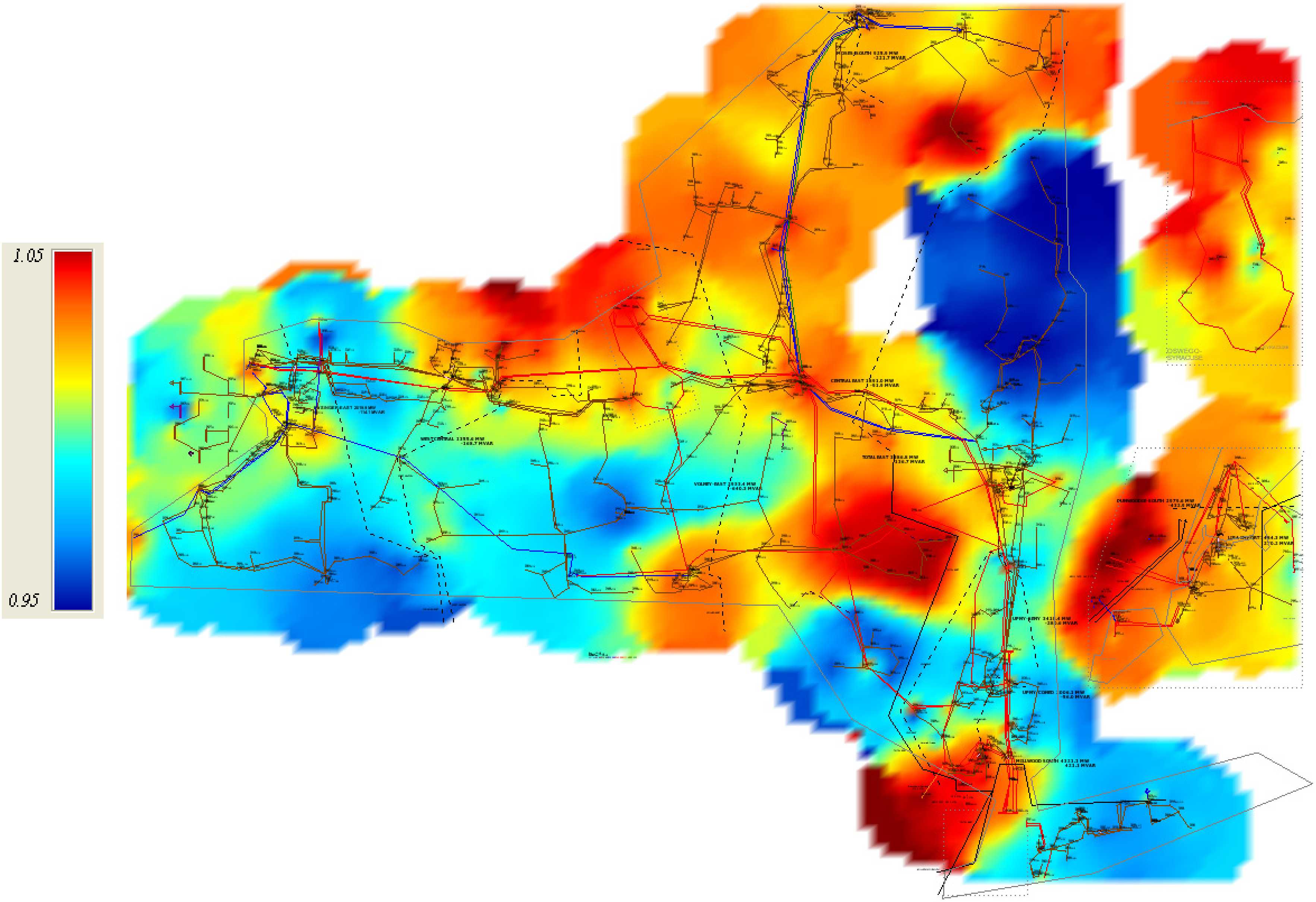


Figure 9.6 (Cont.) - LD5 Case

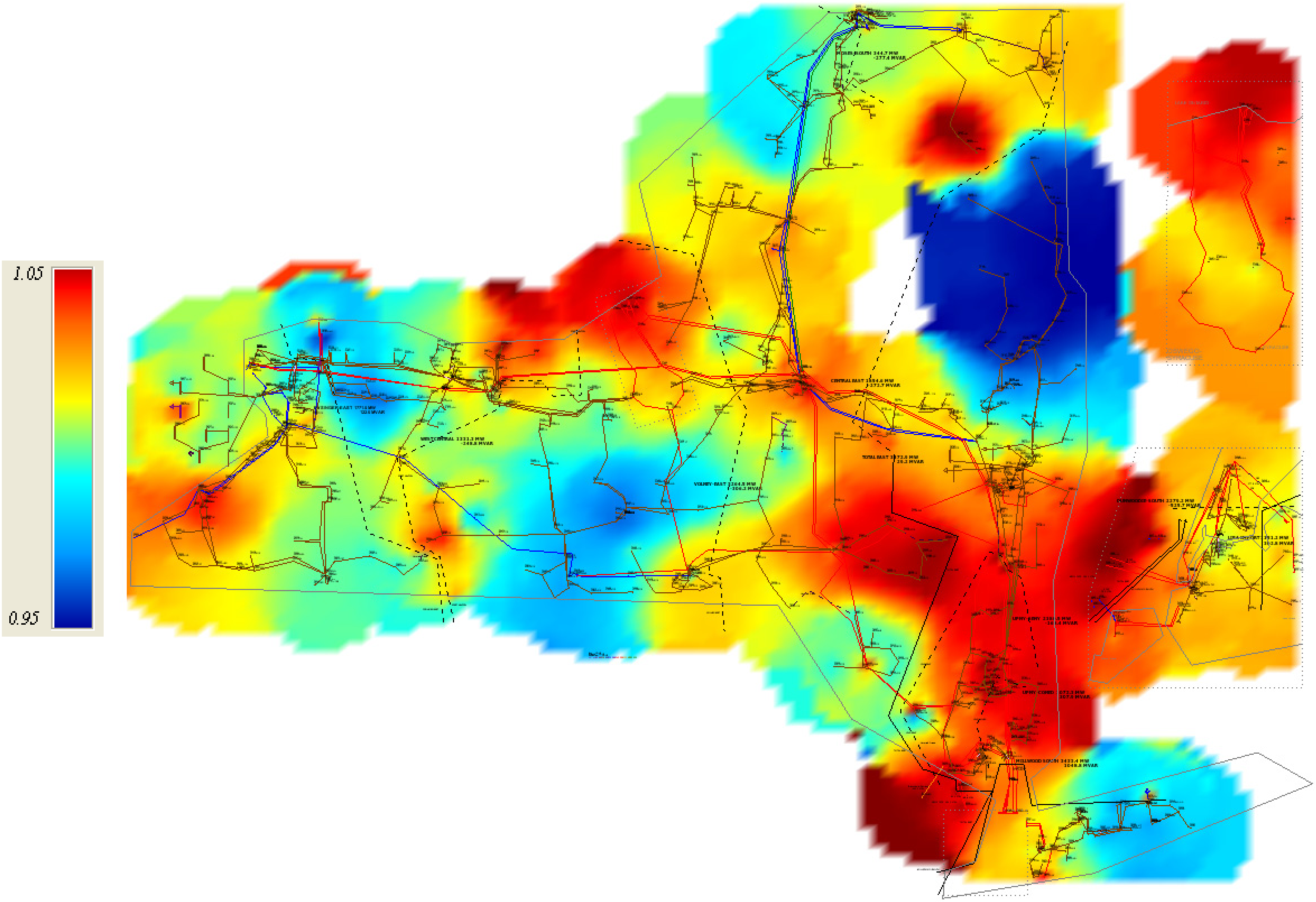


Figure 9.6 (Cont.) - LD6 Case

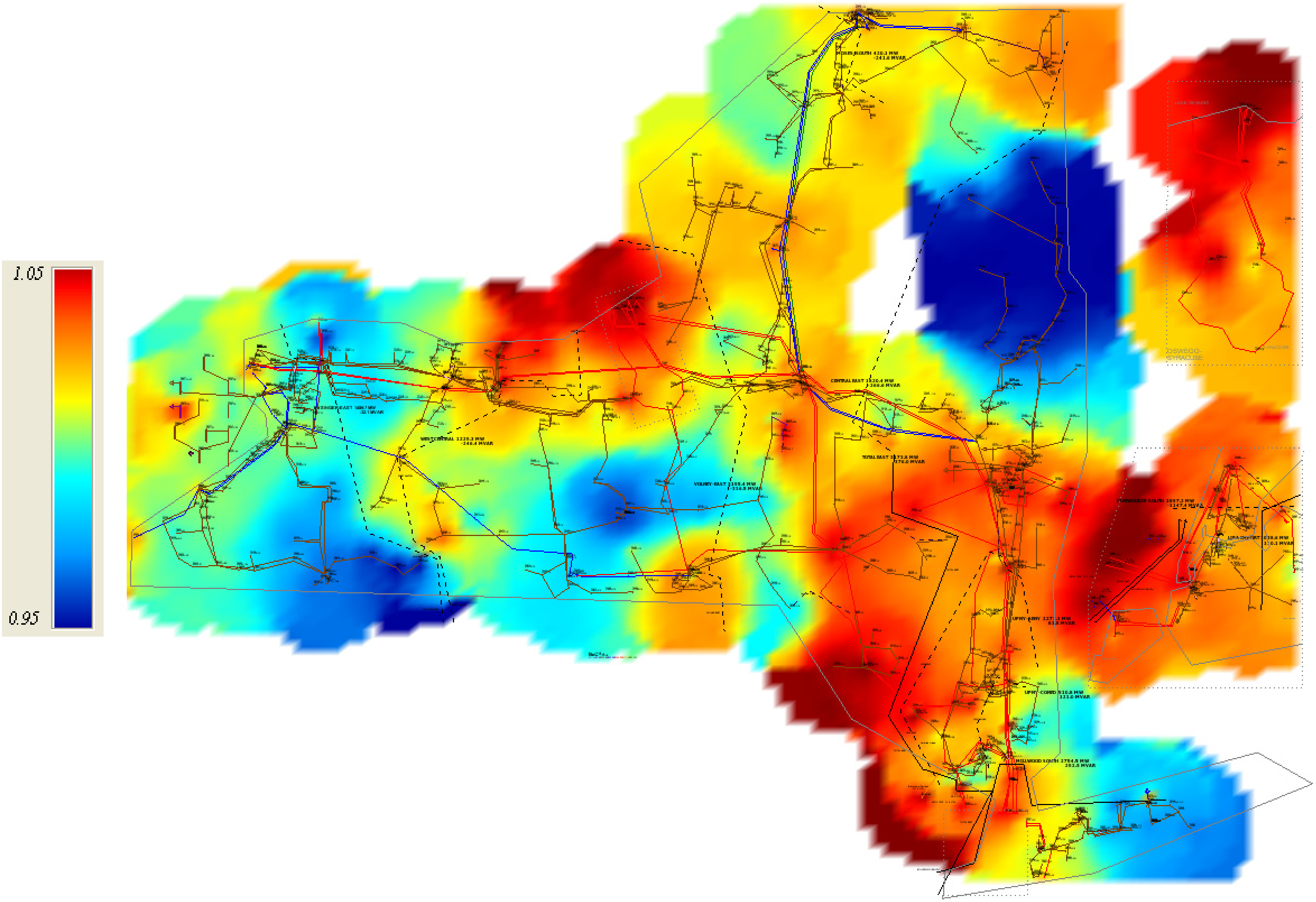


Figure 9.6 (Cont.) - LD7 Case

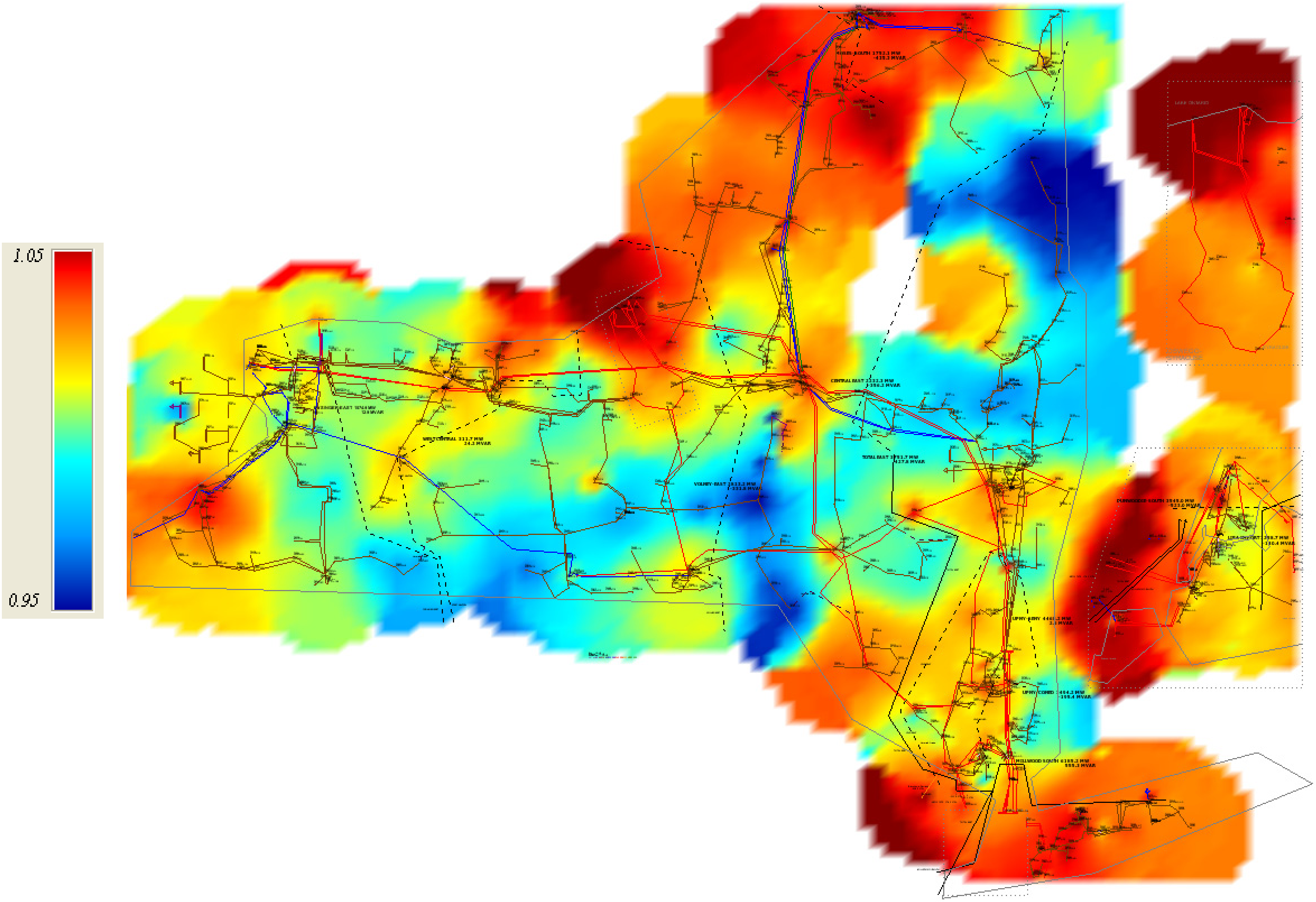


Figure 9.7 - Voltage Magnitudes – 0.95 pu to 1.05 pu Color Scale – 2008 Summer Peak Load Case From NYISO

Table 9.2 – Cases LD1 through LD7 – Zonal Loads, Generation, and Losses

LD1 Case

		LOADS		GENERATION		LOSSES	
AREA	X-- NAME --X	MW	MVAR	MW	MVAR	MW	MVAR
1	WEST	2706.9	1098.5	4385.4	1028.3	89.6	1257.0
2	GENESEE	1982.7	763.4	762.0	173.9	58.2	535.0
3	CENTRAL	2967.8	1331.8	4787.0	1221.1	145.5	1931.7
4	NORTH	834.2	306.0	1388.0	244.0	22.0	324.6
5	MOHAWK	1363.8	518.3	670.3	49.4	178.7	2200.2
6	CAPITAL	2290.9	877.6	3211.0	785.4	106.1	1054.7
7	HUDSON	2342.7	694.4	2475.9	678.7	106.8	1469.9
8	MILLWOOD	610.0	285.8	2101.0	523.2	31.7	791.3
9	DUNWOODI	1434.0	676.0	0.0	0.0	33.0	962.2
10	NYC	11277.3	5321.0	7997.7	1720.3	121.3	4086.3
11	L ISLAND	5389.8	1890.3	4582.9	910.3	86.5	1147.2

LD2 Case

		LOADS		GENERATION		LOSSES	
AREA	X-- NAME --X	MW	MVAR	MW	MVAR	MW	MVAR
1	WEST	2397.6	879.2	4259.7	876.7	89.1	1249.4
2	GENESEE	1673.1	736.0	725.6	40.9	59.2	505.3
3	CENTRAL	2555.1	1059.7	3817.0	822.8	158.0	1901.6
4	NORTH	787.6	242.7	1157.0	112.6	19.7	295.4
5	MOHAWK	1189.0	424.8	319.1	33.1	154.7	1971.3
6	CAPITAL	1951.5	693.9	2654.0	559.9	96.6	910.5
7	HUDSON	1935.6	527.9	1627.7	69.1	99.1	1288.2
8	MILLWOOD	496.7	211.7	2101.0	10.8	27.3	735.4
9	DUNWOODI	1180.5	500.6	0.0	0.0	27.2	832.2
10	NYC	9657.5	3829.6	6622.0	437.1	89.8	2976.6
11	L ISLAND	4395.7	1677.3	3370.1	955.1	67.4	987.3

LD3 Case

		LOADS		GENERATION		LOSSES	
AREA	X-- NAME --X	MW	MVAR	MW	MVAR	MW	MVAR
1	WEST	2202.9	628.7	3936.2	554.9	81.5	1153.5
2	GENESEE	1469.0	689.1	626.0	6.6	55.8	466.6
3	CENTRAL	2325.5	821.2	3777.9	455.0	161.0	1973.5
4	NORTH	782.9	215.3	1065.6	0.0	17.0	231.7
5	MOHAWK	1084.7	353.6	305.6	6.8	130.2	1664.5
6	CAPITAL	1725.6	573.0	2622.6	533.4	95.1	884.8
7	HUDSON	1657.6	376.5	1191.0	319.3	89.4	1138.2
8	MILLWOOD	429.5	158.8	2101.0	107.8	24.6	658.3
9	DUNWOODI	1009.9	375.6	0.0	0.0	23.6	704.7
10	NYC	8479.4	3033.6	5061.9	43.2	74.1	2532.3
11	L ISLAND	3733.0	1635.3	2542.3	247.1	58.0	911.0

LD4 Case

		LOADS		GENERATION		LOSSES	
AREA	X-- NAME --X	MW	MVAR	MW	MVAR	MW	MVAR
1	WEST	2074.7	587.0	3290.6	630.2	72.1	979.1
2	GENESEE	1320.8	633.7	725.1	22.2	48.8	431.3
3	CENTRAL	2185.2	733.3	3432.9	666.9	152.1	1871.7
4	NORTH	796.8	194.6	947.2	0.0	15.1	193.1
5	MOHAWK	1009.6	326.8	482.0	6.7	115.2	1468.2
6	CAPITAL	1529.4	508.8	2034.8	568.4	74.5	648.7
7	HUDSON	1390.4	339.5	941.4	367.1	69.9	844.0
8	MILLWOOD	364.8	138.9	2099.0	251.3	21.7	589.0
9	DUNWOODI	830.1	328.4	0.0	0.0	20.9	396.0
10	NYC	7101.1	2566.6	4065.9	447.4	58.4	2017.8
11	L ISLAND	2977.2	1525.4	1852.3	432.4	42.3	715.9

Table 9.2 (Cont.)

LD5 Case

AREA	X-- NAME --X	LOADS MW	LOADS MVAR	GENERATION MW	GENERATION MVAR	LOSSES MW	LOSSES MVAR
1	WEST	1895.0	567.4	3178.5	689.6	82.2	1062.5
2	GENESEE	1188.1	592.1	575.1	1.2	50.6	436.6
3	CENTRAL	2000.6	716.2	3006.0	511.1	154.7	1910.0
4	NORTH	776.8	174.9	877.7	-1.1	18.1	217.3
5	MOHAWK	905.3	326.2	541.1	6.8	112.5	1370.7
6	CAPITAL	1365.3	484.2	1654.7	379.5	83.7	631.9
7	HUDSON	1237.9	312.5	765.0	188.0	63.8	727.8
8	MILLWOOD	313.5	128.3	2049.0	2.5	19.3	523.1
9	DUNWOODI	728.7	303.4	0.0	0.0	16.7	337.1
10	NYC	6268.0	2381.9	3575.0	582.1	47.4	1529.1
11	L ISLAND	2576.8	1643.5	1457.3	386.2	38.6	658.2

LD6 Case

AREA	X-- NAME --X	LOADS MW	LOADS MVAR	GENERATION MW	GENERATION MVAR	LOSSES MW	LOSSES MVAR
1	WEST	1625.9	465.2	1856.3	780.1	66.6	818.3
2	GENESEE	976.1	604.1	575.1	133.2	39.3	362.6
3	CENTRAL	1709.0	627.7	2984.2	782.7	149.3	1899.7
4	NORTH	739.0	146.6	932.5	5.4	15.7	202.2
5	MOHAWK	741.9	304.2	534.4	32.9	90.3	1055.9
6	CAPITAL	1110.6	412.3	568.9	560.4	68.0	486.2
7	HUDSON	1014.8	278.9	825.0	364.9	34.4	413.0
8	MILLWOOD	242.8	119.1	2049.0	509.9	15.5	439.8
9	DUNWOODI	573.3	281.5	0.0	0.0	12.0	295.8
10	NYC	5066.1	2300.9	2862.9	541.4	35.2	1154.2
11	L ISLAND	2036.7	1498.1	1246.3	457.3	33.2	547.1

LD7 Case

AREA	X-- NAME --X	LOADS MW	LOADS MVAR	GENERATION MW	GENERATION MVAR	LOSSES MW	LOSSES MVAR
1	WEST	1376.5	605.5	1382.6	503.8	50.2	616.6
2	GENESEE	804.7	520.5	575.1	133.4	33.4	312.3
3	CENTRAL	1439.9	610.1	2790.0	780.0	130.9	1722.0
4	NORTH	681.8	131.6	1126.0	102.8	10.9	191.6
5	MOHAWK	594.2	283.3	487.3	29.7	85.5	1029.8
6	CAPITAL	902.2	422.7	178.2	493.3	66.0	600.7
7	HUDSON	829.2	229.7	186.0	-6.8	33.1	406.2
8	MILLWOOD	177.5	93.3	2049.0	-33.8	13.3	400.9
9	DUNWOODI	464.2	220.6	0.0	0.0	10.0	268.6
10	NYC	4230.6	1711.8	2570.1	450.9	26.4	880.5
11	L ISLAND	1646.3	1209.2	958.3	323.5	21.8	363.1

Table 9.3 - Actual vs. Desired Generation Levels

LD1 Case

Generation Area/Zone	Base Case Gen(MW)	Max Gen (MW)	Desired Gen(MW)	LD Step1	Diff W/Desired
A1 (WEST)	4287	4796	4677	4385	-292
B2 (GENESSE)	707	817	759	762	3
C3 (CENTRAL)	4990	6777	5240	4787	-453
D4 (NORTH)	1465	1463	1568	1388	-180
E5 (MHK VL)	598	898	470	670	200
F6 (CAPITAL)	3106	3827	3011	3211	200
G7 (HUD VL)	2406	3025	2275	2476	201
H8 (MILLWOOD)	2114	2112	2407	2101	-306
I9 (DUNWOODIE)	0	0	0	0	0
J10 (CONED)	7201	8134	7998	7998	0
K11 (LIPA)	4280	4930	4289	4583	294
Total:	**31154**	**36779**	**32694**	**32362**	

LD2 Case

Generation Area/Zone	Base Case Gen(MW)	Max Gen (MW)	Desired Gen(MW)	LD Step2	Diff W/Desired
A1 (WEST)	4287	4772	4480	4260	-220
B2 (GENESSE)	707	771	725	726	0
C3 (CENTRAL)	4990	4425	4167	3817	-350
D4 (NORTH)	1465	1417	1447	1157	-290
E5 (MHK VL)	598	585	419	319	-100
F6 (CAPITAL)	3106	3054	2704	2654	-50
G7 (HUD VL)	2406	2843	1258	1628	370
H8 (MILLWOOD)	2114	2110	2415	2101	-314
I9 (DUNWOODIE)	0	0	0	0	0
J10 (CONED)	7201	7959	6752	6622	-130
K11 (LIPA)	4280	4492	3424	3370	-54
Total:	**31154**	**32429**	**27791**	**26653**	

LD3 Case

Generation Area/Zone	Base Case Gen(MW)	Max Gen (MW)	Desired Gen(MW)	LD Step3	Diff W/Desired
A1 (WEST)	4287	4772	4205	3936	-269
B2 (GENESSE)	707	771	776	626	-150
C3 (CENTRAL)	4990	4425	4178	3778	-400
D4 (NORTH)	1465	1417	1373	1066	-307
E5 (MHK VL)	598	585	406	306	-100
F6 (CAPITAL)	3106	2884	2423	2623	200
G7 (HUD VL)	2406	1615	801	1191	390
H8 (MILLWOOD)	2114	2110	2443	2101	-342
I9 (DUNWOODIE)	0	0	0	0	0
J10 (CONED)	7201	5797	5362	5062	-300
K11 (LIPA)	4280	2796	2542	2542	0
Total:	**31154**	**27172**	**24508**	**23230**	

Table 9.3 (Cont.)

LD4 Case

Generation Area/Zone	Base Case Gen(MW)	Max Gen (MW)	Desired Gen(MW)	LD Step4	Diff W/Desired
A1 (WEST)	4287	4772	4087	3291	-796
B2 (GENESSE)	707	771	825	725	-100
C3 (CENTRAL)	4990	4281	4013	3433	-580
D4 (NORTH)	1465	1235	1317	947	-370
E5 (MHK VL)	598	585	482	482	0
F6 (CAPITAL)	3106	2806	2135	2035	-100
G7 (HUD VL)	2406	1615	601	941	340
H8 (MILLWOOD)	2114	2110	2444	2099	-345
I9 (DUNWOODIE)	0	0	0	0	0
J10 (CONED)	7201	4453	3666	4066	400
K11 (LIPA)	4280	2683	1681	1852	172
Total:	**31154**	**25311**	**21251**	**19871**	

LD5 Case

Generation Area/Zone	Base Case Gen(MW)	Max Gen (MW)	Desired Gen(MW)	LD Step5	Diff W/Desired
A1 (WEST)	4287	4273	3606	3179	-427
B2 (GENESSE)	707	606	750	575	-175
C3 (CENTRAL)	4990	3357	3693	3006	-687
D4 (NORTH)	1465	935	1328	878	-450
E5 (MHK VL)	598	585	491	541	50
F6 (CAPITAL)	3106	2312	1795	1655	-140
G7 (HUD VL)	2406	1615	515	765	250
H8 (MILLWOOD)	2114	2058	2396	2049	-347
I9 (DUNWOODIE)	0	0	0	0	0
J10 (CONED)	7201	4018	3047	3575	528
K11 (LIPA)	4280	2046	1342	1457	116
Total:	**31154**	**21805**	**18963**	17679	

LD6 Case

Generation Area/Zone	Base Case Gen(MW)	Max Gen (MW)	Desired Gen(MW)	LD Step6	Diff W/Desired
A1 (WEST)	4287	4273	2556	1856	-700
B2 (GENESSE)	707	606	741	575	-166
C3 (CENTRAL)	4990	3357	3484	2984	-500
D4 (NORTH)	1465	935	1242	932	-310
E5 (MHK VL)	598	585	474	534	60
F6 (CAPITAL)	3106	2022	919	569	-350
G7 (HUD VL)	2406	1615	445	825	380
H8 (MILLWOOD)	2114	2058	2383	2049	-334
I9 (DUNWOODIE)	0	0	0	0	0
J10 (CONED)	7201	3288	2363	2863	500
K11 (LIPA)	4280	1996	988	1246	259
Total:	**31154**	**20735**	**15595**	**14435**	

Table 9.3 (Cont.)

LD7 Case

Generation Area/Zone	Base Case Gen(MW)	Max Gen (MW)	Desired Gen(MW)	LD Step7	Diff W/Desired
A1 (WEST)	4287	2348	1983	1383	-600
B2 (GENESSE)	707	606	432	575	143
C3 (CENTRAL)	4990	3357	3390	2790	-600
D4 (NORTH)	1465	1176	1327	1126	-201
E5 (MHK VL)	598	585	467	487	20
F6 (CAPITAL)	3106	1660	278	178	-100
G7 (HUD VL)	2406	241	266	186	-80
H8 (MILLWOOD)	2114	2058	2249	2049	-200
I9 (DUNWOODIE)	0	0	0	0	0
J10 (CONED)	7201	2754	1795	2570	775
K11 (LIPA)	4280	1622	760	958	199
Total:	**31154**	**16407**	**12947**	**12303**	

Table 9.4 - Actual vs. Desired Interface Flow Levels

LD1 Case

Interface	Base Case Flow(MW)	Desired Flow(MW)	LD Step1	Diff W/Desired
Dysinger East	1575	1867	1716	-151
West-Central	270	752	401	-351
Moses South	1752	1807	1844	37
Central-East	2347	2135	2186	51
Total-East	3855	2822	3341	519
UPNY-ConEd	3494	2785	3296	511
Dunwoodie South	2944	2597	2653	55
Hydro Quebec (Imports)	1200	1381	1376	-4
ISO NE (Imports)	262	455	452	-3
IMO (Imports)	-368	205	-142	-347
PJM (Imports)	313	-837	211	1048
NEPTUNE	327	250	249	-1
SHOREHAM	330	330	330	0
CONED-LIPA	604	640	645	5

LD2 Case

Interface	Base Case Flow(MW)	Desired Flow(MW)	LD Step2	Diff W/Desired
Dysinger East	1575	1968	2007	40
West-Central	270	1021	966	-56
Moses South	1752	1782	1865	83
Central-East	2347	1967	2036	70
Total-East	3855	3088	3384	296
UPNY-ConEd	3494	2531	2626	95
Dunwoodie South	2944	2639	2559	-79
Hydro Quebec (Imports)	1200	1378	1373	-5
ISO NE (Imports)	262	576	605	30
IMO (Imports)	-368	336	250	-86
PJM (Imports)	313	-131	-94	37
NEPTUNE	327	660	650	-10
SHOREHAM	330	330	330	0
CONED-LIPA	604	367	444	77

Table 9.4 (Cont.)

LD3 Case

Interface	Base Case Flow(MW)	Desired Flow(MW)	LD Step3	Diff W/Desired
Dysinger East	1575	1860	2041	181
West-Central	270	1115	1110	-5
Moses South	1752	1378	1386	8
Central-East	2347	1917	1956	39
Total-East	3855	3476	3767	290
UPNY-ConEd	3494	2516	2697	181
Dunwoodie South	2944	2733	2719	-14
Hydro Quebec (Imports)	1200	1069	1071	3
ISO NE (Imports)	262	430	454	23
IMO (Imports)	-368	296	291	-5
PJM (Imports)	313	348	344	-4
NEPTUNE	327	660	650	-10
SHOREHAM	330	330	330	0
CONED-LIPA	604	533	599	66

LD4 Case

Interface	Base Case Flow(MW)	Desired Flow(MW)	LD Step4	Diff W/Desired
Dysinger East	1575	1790	1869	78
West-Central	270	1209	1195	-14
Moses South	1752	1049	1031	-18
Central-East	2347	1842	1864	22
Total-East	3855	3740	3560	-180
UPNY-ConEd	3494	2420	2418	-2
Dunwoodie South	2944	2780	2770	-11
Hydro Quebec (Imports)	1200	848	852	4
ISO NE (Imports)	262	199	268	69
IMO (Imports)	-368	202	466	264
PJM (Imports)	313	834	494	-340
NEPTUNE	327	660	650	-10
SHOREHAM	330	330	330	0
CONED-LIPA	604	551	519	-32

Table 9.4 (Cont.)

LD5 Case

Interface	Base Case Flow(MW)	Desired Flow(MW)	LD Step5	Diff W/Desired
Dysinger East	1575	1838	2020	182
West-Central	270	1334	1327	-6
Moses South	1752	877	926	49
Central-East	2347	1819	1901	82
Total-East	3855	3666	3578	-88
UPNY-ConEd	3494	2007	2006	-1
Dunwoodie South	2944	2448	2475	27
Hydro Quebec (Imports)	1200	588	601	13
ISO NE (Imports)	262	-3	20	23
IMO (Imports)	-368	593	718	125
PJM (Imports)	313	819	606	-213
NEPTUNE	327	660	650	-10
SHOREHAM	330	330	330	0
CONED-LIPA	604	546	509	-37

LD6 Case

Interface	Base Case Flow(MW)	Desired Flow(MW)	LD Step6	Diff W/Desired
Dysinger East	1575	1625	1771	146
West-Central	270	1307	1306	-1
Moses South	1752	421	345	-77
Central-East	2347	1787	1865	78
Total-East	3855	3594	3463	-131
UPNY-ConEd	3494	1110	1072	-38
Dunwoodie South	2944	1902	2001	99
Hydro Quebec (Imports)	1200	29	31	2
ISO NE (Imports)	262	-461	-435	26
IMO (Imports)	-368	1058	1281	223
PJM (Imports)	313	1045	871	-173
NEPTUNE	327	550	543	-7
SHOREHAM	330	330	330	0
CONED-LIPA	604	423	282	-141

Table 9.4 (Cont.)

LD7 Case

Interface	Base Case Flow(MW)	Desired Flow(MW)	LD Step7	Diff W/Desired
Dysinger East	1575	1481	1490	9
West-Central	270	1091	1207	116
Moses South	1752	440	420	-20
Central-East	2347	1831	1888	58
Total-East	3855	3225	3221	-4
UPNY-ConEd	3494	500	511	11
Dunwoodie South	2944	1537	1634	97
Hydro Quebec (Imports)	1200	-118	-121	-3
ISO NE (Imports)	262	-448	-407	41
IMO (Imports)	-368	1223	1213	-10
PJM (Imports)	313	303	524	221
NEPTUNE	327	450	445	-5
SHOREHAM	330	330	330	0
CONED-LIPA	604	283	265	-18

Table 9.5 – NYCA Voltages Outside of 95% to 105% Range

LD1 Case

BUSES WITH VOLTAGE GREATER THAN 1.0500:

BUS#	X-- NAME --X	BASKV	AREA	V(PU)	V(KV)	BUS#	X-- NAME --X	BASKV	AREA	V(PU)	V(KV)
126250	RAMAPO 5	500.00	7	1.0656	532.78	126284	GOTHLS R	345.00	10	1.0500	362.26
126321	GOETHALS	230.00	10	1.0500	241.50	126427	GOWNUS1T	138.00	10	1.0551	145.61
126429	GOWNUS2T	138.00	10	1.0562	145.76	126733	PLTVILLE	13.800	9	1.0536	14.540
128842	NEPTCONV	345.00	11	1.0508	362.52	129293	SHORE RD	138.00	11	1.0504	144.95
129321	BAGATELLE	138.00	11	1.0505	144.96	129342	NRTHPRT2	138.00	11	1.0503	144.94
129650	SYOSSET	69.000	11	1.0503	72.470	129686	PILGRM	69.000	11	1.0503	72.469
129731	C.ISLIP	69.000	11	1.0502	72.464	130011	GRNLWN1	23.000	11	1.0503	24.156
130029	EASTPORT	23.000	11	1.0501	24.153	130035	SOUTHOLD	23.000	11	1.0500	24.150
131070	N.ENDIC1	34.500	3	1.0500	36.225	131074	NSIDE234	34.500	3	1.0500	36.227
131106	GOUDEY7M	13.800	3	1.0519	14.516	135800	HNTLY67G	13.800	1	1.0536	14.539
135801	HNTLY68G	13.800	1	1.0536	14.539	136478	LHH	34.500	3	1.0500	36.225
136479	LHH TAP1	34.500	3	1.0500	36.225	137045	MCINTYRE	23.000	5	1.0501	24.152
137169	FRONTENA	2.4000	5	1.0500	2.520	137632	O. C. 13	13.200	6	1.0500	13.860
137701	JMCGT13	13.800	6	1.0558	14.570	137703	JMCGT213	13.800	6	1.0558	14.570
137709	LGE-GT	13.800	6	1.0500	14.490	137710	LGE-ST	13.800	6	1.0500	14.490
147766	MOS21-22	13.800	4	1.0500	14.490	147770	MOS23-24	13.800	4	1.0500	14.490

BUSES WITH VOLTAGE LESS THAN 0.9500:

BUS#	X-- NAME --X	BASKV	AREA	V(PU)	V(KV)	BUS#	X-- NAME --X	BASKV	AREA	V(PU)	V(KV)
131473	ALDEN 34	34.500	1	0.9485	32.722	131477	BENNGTON	34.500	1	0.9494	32.755
131492	COWLESVL	34.500	1	0.9485	32.724	131502	GARDN M7	34.500	1	0.9486	32.726
131529	3 ROD RD	34.500	1	0.9486	32.727	131533	SLOAN 34	34.500	1	0.9497	32.766
131542	WENDE 34	34.500	1	0.9485	32.723	131670	BARRET46	46.000	5	0.9500	43.700
131748	JENN 2G	13.800	5	0.9500	13.110	135425	PETROLIA	34.500	1	0.9500	32.774
135587	ELMST23.	23.000	1	0.9495	21.838	135965	DARIEN	34.500	2	0.9495	32.759
135966	DARIENLK	34.500	2	0.9496	32.762	136899	BRAS VRG	34.500	4	0.9500	32.774
137322	O.F. REG	46.000	5	0.9494	43.671	137615	LATHAM	34.500	6	0.9500	32.775
137656	STYV+CHY	34.500	6	0.9500	32.775	137915	WEIBEL1	115.00	6	0.9500	109.25
138007	SCR+POTR	34.500	6	0.9500	32.774	138024	GILM+CHL	23.000	6	0.9500	21.849
138028	SCHENEVS	23.000	6	0.9500	21.849	147947	WATK GLN	34.500	3	0.9499	32.772
147949	WELLSVLE	115.00	1	0.9499	109.24	149041	S8132VR	34.500	2	0.9497	32.763
149147	STA56-25	12.000	2	0.9498	11.398	149174	S7 B	11.500	2	0.9499	10.924
149225	S173BOL	34.500	2	0.9499	32.771	149230	S8312VS	34.500	2	0.9498	32.769
149332	S194C708	34.500	2	0.9498	32.769	149333	S8205VRS	34.500	2	0.9498	32.769

Table 9.5 (Cont.)

LD2 Case

BUSES WITH VOLTAGE GREATER THAN 1.0500:

BUS#	X-- NAME --X	BASKV	AREA	V(PU)	V(KV)	BUS#	X-- NAME --X	BASKV	AREA	V(PU)	V(KV)
126284	GOTHLS R	345.00	10	1.0500	362.25	126321	GOETHALS	230.00	10	1.0500	241.50
126427	GOWNUS1T	138.00	10	1.0551	145.61	126429	GOWNUS2T	138.00	10	1.0543	145.49
126733	PLTVILLE	13.800	9	1.0532	14.534	130035	SOUTHOLD	23.000	11	1.0500	24.150
131082	S.OWEGO2	34.500	3	1.0500	36.225	131381	SPERRY34	34.500	3	1.0500	36.225
135800	HNTLY67G	13.800	1	1.0502	14.492	135801	HNTLY68G	13.800	1	1.0502	14.492
135977	GENESEO	34.500	2	1.0501	36.228	136730	ESYR ST1	13.200	3	1.0646	14.052
137701	JMCGT13	13.800	6	1.0546	14.554	137703	JMCGT213	13.800	6	1.0546	14.554
137709	LGE-GT	13.800	6	1.0500	14.490						

BUSES WITH VOLTAGE LESS THAN 0.9500:

BUS#	X-- NAME --X	BASKV	AREA	V(PU)	V(KV)	BUS#	X-- NAME --X	BASKV	AREA	V(PU)	V(KV)
125194	DANSK G3	16.100	7	0.9483	15.268	126460	OSS W TF	138.00	8	0.9499	131.08
126461	OSS W TF	138.00	8	0.9499	131.08	128958	GLNWDMID	13.800	11	0.9489	13.094
129139	SHAMP_GT	13.800	11	0.9499	13.109	129788	BNLBOOST	69.000	11	0.9499	65.542
129790	BRKHAVEN	69.000	11	0.9499	65.542	129821	N.BELLPT	69.000	11	0.9499	65.545
129832	RIDGE	69.000	11	0.9499	65.545	130791	CORN TP1	115.00	3	0.9499	109.24
131395	CORN1115	115.00	3	0.9499	109.24	131396	CORN2115	115.00	3	0.9500	109.25
131397	E.ITH115	115.00	3	0.9500	109.25	131399	CORNEL $	115.00	3	0.9499	109.24
131443	SO.HILL	34.500	3	0.9499	32.771	131525	ORCHRD P	34.500	1	0.9500	32.773
135397	CLVRBK13	13.200	1	0.9499	12.539	135825	STA139	4.1600	1	0.9500	3.952
135965	DARIEN	34.500	2	0.9500	32.774	136899	BRAS VRG	34.500	4	0.9497	32.766
137026	HAMMOND	23.000	5	0.9500	21.850	137175	DIAM ISL	2.3000	5	0.9500	2.185
137176	E NORFOK	2.3000	5	0.9500	2.185	137322	O.F. REG	46.000	5	0.9492	43.664
137656	STYV+CHY	34.500	6	0.9500	32.775	137666	TIB+RPI	34.500	6	0.9500	32.774
137898	PORT HEN	115.00	6	0.9500	109.25	138007	SCR+POTR	34.500	6	0.9500	32.775
138024	GILM+CHL	23.000	6	0.9500	21.849	146771	SHOEM138	138.00	7	0.9500	131.10
146835	WURTSBOR	34.500	7	0.9500	32.775	147947	WATK GLN	34.500	3	0.9500	32.774
147948	WATOWMU	2.3000	5	0.9500	2.185	149147	STA56-25	12.000	2	0.9500	11.400
149225	S173BOL	34.500	2	0.9500	32.774						

Table 9.5 (Cont.)

LD3 Case

BUSES WITH VOLTAGE GREATER THAN 1.0500:

BUS#	X-- NAME --X	BASKV	AREA	V(PU)	V(KV)	BUS#	X-- NAME --X	BASKV	AREA	V(PU)	V(KV)
126250	RAMAPO 5	500.00	7	1.0999	549.93	126427	GOWNUS1T	138.00	10	1.0540	145.45
126429	GOWNUS2T	138.00	10	1.0551	145.60	135576	BUFSEWLV	13.800	1	1.0504	14.496
135807	FORD	13.200	1	1.0501	13.862	135977	GENESEO	34.500	2	1.0501	36.228
137045	MCINTYRE	23.000	5	1.0501	24.152	137709	LGE-GT	13.800	6	1.0500	14.490
137921	FLATRKGN	0.6000	5	1.0500	0.630	138026	NORTHV23	23.000	6	1.0500	24.150
149025	PANNELLI	115.00	2	1.0500	120.75						

BUSES WITH VOLTAGE LESS THAN 0.9500:

BUS#	X-- NAME --X	BASKV	AREA	V(PU)	V(KV)	BUS#	X-- NAME --X	BASKV	AREA	V(PU)	V(KV)
129087	HOLTS D	13.800	11	0.9497	13.106	129102	SHRHM D	13.800	11	0.9498	13.107
129796	EASTPORT	69.000	11	0.9497	65.528	129832	RIDGE	69.000	11	0.9497	65.532
129886	SUFLKAIR	69.000	11	0.9497	65.527	130044	HERO	23.000	11	0.9496	21.842
130773	BARTN115	115.00	6	0.9500	109.24	131395	CORN1115	115.00	3	0.9500	109.25
131399	CORNEL $	115.00	3	0.9500	109.25	135391	DUNKGEN4	13.800	1	0.9498	13.107
135800	HNTLY67G	13.800	1	0.9485	13.089	135801	HNTLY68G	13.800	1	0.9485	13.089
137322	O.F. REG	46.000	5	0.9494	43.674	137656	STYV+CHY	34.500	6	0.9500	32.775
137666	TIB+RPI	34.500	6	0.9500	32.774	149230	S8312VS	34.500	2	0.9500	32.773

LD4 Case

BUSES WITH VOLTAGE GREATER THAN 1.0500:

BUS#	X-- NAME --X	BASKV	AREA	V(PU)	V(KV)	BUS#	X-- NAME --X	BASKV	AREA	V(PU)	V(KV)
126250	RAMAPO 5	500.00	7	1.1000	549.98	131261	BORDER34	34.500	3	1.0500	36.225
131490	COBHIL34	34.500	1	1.0500	36.225	131515	GIRD34	34.500	1	1.0501	36.230
135576	BUFSEWLV	13.800	1	1.0503	14.495	135807	FORD	13.200	1	1.0501	13.862
135977	GENESEO	34.500	2	1.0501	36.229	136025	TELRD34	34.500	2	1.0500	36.225
136777	LK COLBY	115.00	4	1.0501	120.76	136918	MALONE 3	34.500	4	1.0502	36.230
137045	MCINTYRE	23.000	5	1.0501	24.152	137709	LGE-GT	13.800	6	1.0500	14.490
137985	HOOSICK	34.500	6	1.0500	36.225	147843	PLAT T#1	230.00	4	1.0500	241.50
149025	PANNELLI	115.00	2	1.0500	120.75						

BUSES WITH VOLTAGE LESS THAN 0.9500:

BUS#	X-- NAME --X	BASKV	AREA	V(PU)	V(KV)	BUS#	X-- NAME --X	BASKV	AREA	V(PU)	V(KV)
129087	HOLTS D	13.800	11	0.9497	13.105	129102	SHRHM D	13.800	11	0.9498	13.107
129796	EASTPORT	69.000	11	0.9496	65.525	129832	RIDGE	69.000	11	0.9497	65.529
129886	SUFLKAIR	69.000	11	0.9496	65.525	130044	HERO	23.000	11	0.9496	21.842
137322	O.F. REG	46.000	5	0.9495	43.677	137666	TIB+RPI	34.500	6	0.9500	32.774
147947	WATK GLN	34.500	3	0.9500	32.774	149147	STA56-25	12.000	2	0.9500	11.400

Table 9.5 (Cont.)

LD5 Case

BUSES WITH VOLTAGE GREATER THAN 1.0500:

BUS#	X-- NAME --X	BASKV	AREA	V(PU)	V(KV)	BUS#	X-- NAME --X	BASKV	AREA	V(PU)	V(KV)
126250	RAMAPO 5	500.00	7	1.1000	549.98	131786	KENTSF46	46.000	4	1.0500	48.301
136777	LK COLBY	115.00	4	1.0501	120.76	136918	MALONE 3	34.500	4	1.0502	36.231
136966	BOONVILL	23.000	5	1.0500	24.151	137018	GLENF TA	23.000	5	1.0500	24.150
137019	GLENFIEL	23.000	5	1.0500	24.150	137044	LOWVILLE	23.000	5	1.0500	24.150
137045	MCINTYRE	23.000	5	1.0501	24.152	137210	PORTER 2	230.00	5	1.0500	241.50
137709	LGE-GT	13.800	6	1.0500	14.490	137710	LGE-ST	13.800	6	1.0500	14.490
137714	BETH STM	18.000	6	1.0500	18.900						

BUSES WITH VOLTAGE LESS THAN 0.9500:

BUS#	X-- NAME --X	BASKV	AREA	V(PU)	V(KV)	BUS#	X-- NAME --X	BASKV	AREA	V(PU)	V(KV)
125194	DANSK G3	16.100	7	0.9464	15.237	129087	HOLTS D	13.800	11	0.9493	13.100
129102	SHRHM D	13.800	11	0.9495	13.103	129794	CORAM	69.000	11	0.9497	65.530
129796	EASTPORT	69.000	11	0.9492	65.498	129819	MT.SINAI	69.000	11	0.9498	65.537
129832	RIDGE	69.000	11	0.9493	65.503	129886	SUFLKAIR	69.000	11	0.9492	65.497
130044	HERO	23.000	11	0.9492	21.830	131327	ELINGTON	34.500	1	0.9498	32.769
131380	PORTAGE	34.500	3	0.9496	32.759	131516	JAMISON	34.500	1	0.9489	32.736
131525	ORCHRD P	34.500	1	0.9486	32.727	131548	WALDA113	13.090	1	0.9498	12.433
131632	ROBIN M1	34.500	1	0.9486	32.725	135337	DELEVAN	34.500	1	0.9489	32.738
135387	FRENCHCR	34.500	1	0.9500	32.774	135395	BENNETT	13.200	1	0.9497	12.536
135425	PETROLIA	34.500	1	0.9498	32.768	135587	ELMST23.	23.000	1	0.9497	21.842
135597	KTS23	23.000	1	0.9486	21.818	135615	SENST20	23.000	1	0.9487	21.820
135813	STA140	13.200	1	0.9474	12.506	135882	MUMFORD	13.200	2	0.9498	12.537
135917	E GOLAH	13.200	2	0.9495	12.533	135940	ALBION	34.500	2	0.9491	32.746
135955	BUTTSRD	34.500	2	0.9487	32.729	137322	O.F. REG	46.000	5	0.9495	43.679
137666	TIB+RPI	34.500	6	0.9500	32.774	137880	EJW+STWB	115.00	6	0.9500	109.25
137897	OGN BRK5	115.00	6	0.9500	109.25	137898	PORT HEN	115.00	6	0.9500	109.25
137976	CORINTH	34.500	6	0.9500	32.774	147883	CASTILLE	34.500	3	0.9500	32.775
147947	WATK GLN	34.500	3	0.9497	32.763	149147	STA56-25	12.000	2	0.9496	11.395

LD6 Case

BUSES WITH VOLTAGE GREATER THAN 1.0500:

BUS#	X-- NAME --X	BASKV	AREA	V(PU)	V(KV)	BUS#	X-- NAME --X	BASKV	AREA	V(PU)	V(KV)
126250	RAMAPO 5	500.00	7	1.0837	541.86	126261	BOWLINE2	345.00	7	1.0500	362.25
131786	KENTSF46	46.000	4	1.0500	48.300	135533	RANSOMVL	34.500	1	1.0501	36.227
135800	HNTLY67G	13.800	1	1.0501	14.491	135801	HNTLY68G	13.800	1	1.0501	14.491
136777	LK COLBY	115.00	4	1.0501	120.76	136918	MALONE 3	34.500	4	1.0502	36.231
136966	BOONVILL	23.000	5	1.0501	24.151	137701	JMCGT13	13.800	6	1.0554	14.565
137703	JMCGT213	13.800	6	1.0554	14.565	137710	LGE-ST	13.800	6	1.0500	14.490

Table 9.5 (Cont.)

BUSES WITH VOLTAGE LESS THAN 0.9500:

BUS#	X-- NAME --X	BASKV	AREA	V(PU)	V(KV)	BUS#	X-- NAME --X	BASKV	AREA	V(PU)	V(KV)
128916	FROCKGT2	13.800	11	0.9495	13.103	129796	EASTPORT	69.000	11	0.9499	65.543
129832	RIDGE	69.000	11	0.9500	65.547	129886	SUFLKAIR	69.000	11	0.9499	65.543
131632	ROBIN M1	34.500	1	0.9494	32.753	135965	DARIEN	34.500	2	0.9495	32.757
135966	DARIENLK	34.500	2	0.9495	32.756	137026	HAMMOND	23.000	5	0.9500	21.849
137870	BURGOYNE	115.00	6	0.9500	109.25	137882	GRT MDWS	115.00	6	0.9500	109.25
137888	IP TICON	115.00	6	0.9500	109.24	137914	WBURG115	115.00	6	0.9500	109.25
137976	CORINTH	34.500	6	0.9500	32.775	147904	HOLLEY	34.500	2	0.9494	32.756
149147	STA56-25	12.000	2	0.9498	11.398						

LD7 Case

BUSES WITH VOLTAGE GREATER THAN 1.0500:

BUS#	X-- NAME --X	BASKV	AREA	V(PU)	V(KV)	BUS#	X-- NAME --X	BASKV	AREA	V(PU)	V(KV)
125046	ROCK TV1	115.00	7	1.0507	120.83	125092	CHELSEA	69.000	7	1.0502	72.461
125096	E.WALD 6	69.000	7	1.0511	72.528	126250	RAMAPO 5	500.00	7	1.1020	551.01
126278	FARRGUT1	345.00	10	1.0578	364.95	126279	FARRGUT2	345.00	10	1.0595	365.53
126284	GOTHLS R	345.00	10	1.0513	362.69	126321	GOETHALS	230.00	10	1.0514	241.82
130029	EASTPORT	23.000	11	1.0505	24.161	130035	SOUTHOLD	23.000	11	1.0504	24.159
130750	COOPC345	345.00	5	1.0508	362.53	130790	COOPC115	115.00	5	1.0515	120.92
130805	FRASR115	115.00	5	1.0504	120.80	130908	MARIETTA	34.500	3	1.0500	36.225
130945	COMSTOCK	34.500	6	1.0501	36.227	130996	SALEM Y	34.500	6	1.0500	36.226
131091	W.UNION	34.500	3	1.0501	36.229	131106	GOUDEY7M	13.800	3	1.0502	14.493
131676	C.LINE46	46.000	5	1.0502	48.308	131786	KENTSF46	46.000	4	1.0500	48.300
135800	HNTLY67G	13.800	1	1.0549	14.558	135801	HNTLY68G	13.800	1	1.0549	14.558
136478	LHH	34.500	3	1.0500	36.226	136479	LHH TAP1	34.500	3	1.0500	36.226
136918	MALONE 3	34.500	4	1.0502	36.233	136966	BOONVILL	23.000	5	1.0501	24.153
137632	O. C. 13	13.200	6	1.0502	13.863	137643	ROTTDM	34.500	6	1.0502	36.231
137944	MARSH 69	69.000	6	1.0501	72.456	137985	HOOSICK	34.500	6	1.0501	36.230
137989	KREG+RIP	34.500	6	1.0500	36.226	137990	KNAPP RD	34.500	6	1.0500	36.226
137997	NO CREEK	34.500	6	1.0501	36.229	138014	WBURGREG	34.500	6	1.0501	36.230
146772	SHOEMTAP	138.00	7	1.0524	145.23						

BUSES WITH VOLTAGE LESS THAN 0.9500:

BUS#	X-- NAME --X	BASKV	AREA	V(PU)	V(KV)	BUS#	X-- NAME --X	BASKV	AREA	V(PU)	V(KV)
131501	NIA ENVL	34.500	1	0.9484	32.720	131506	HOLAND T	34.500	1	0.9485	32.725
131507	HOLLAND	34.500	1	0.9485	32.724	135260	ANDOVER1	115.00	1	0.9489	109.13
135587	ELMST23.	23.000	1	0.9494	21.837	135944	ATTICA	34.500	2	0.9485	32.725
135954	BURT	34.500	1	0.9499	32.773	135992	LINDEN	34.500	2	0.9490	32.739
135998	L209REGL	34.500	2	0.9480	32.704	147947	WATK GLN	34.500	3	0.9499	32.773
147949	WELLSVLE	115.00	1	0.9498	109.23	149147	STA56-25	12.000	2	0.9496	11.395

10 LOSS SENSITIVITY ANALYSES

10.1 INTRODUCTION

Prior to starting analysis of options for loss minimization, loss sensitivity analyses were conducted. Sensitivities are a by-product of OPF runs, and are listings of the derivative of the objective function to various control variables. In the analyses described in this section the objective function was minimization of NYCA (Areas 1 through 11 in PSS/E) MW losses, and the control variables were the fictitious incremental injection of MW and Mvar at each of the NYCA buses.

No constraints were modeled, other in that generators were instructed to behave as in conventional power flow; i.e., to hold voltages subject to reactive limits. Bus voltages limits were set to a wide 0.8 to 1.2 pu range.

Essentially no control action was allowed by the OPF. Generators were not allowed to modify their terminal voltages. Nor were they allowed to modify their MW dispatch. Transformers, phase shifters and switched shunts were not allowed to adjust.

Hence, the powerflow conditions after OPF application remained essentially the same as in the seven load step powerflows described in previous sections.

The results allow a “birds’ eye view” of the overall impact MW (e.g. generation redispatch) and Mvar (e.g., switching in and out of shunt compensation) injections would have on NYCA MW losses and thus provide guidance on what and where opportunities for loss reduction might be.

10.2 CASE PREPARATION

The following changes were made to the LD1 through LD7 cases:

- For the purpose of clarity, “moving” the swing bus to one of the units at the Niagara Station (Old Bus# 79500, New Bus # 147750). This had no impact on the powerflow condition, and was done mainly for the purpose of providing an adequate scale to OPF results.
- Disabling the SVCs at Fraser and Leeds, as well as the STATCOM at Marcy. This was done because their output is assumed reserved for contingencies.
- Likewise, every NYISO generator whose reactive power output was limited during the case development, either because of it reaching its maximum reactive limit, or because of its reactive output exceeding a 0.98 power factor (on the basis of generator MVA Base), was “netted-out” as a negative load.

10.3 SENSITIVITY TO ACTIVE POWER INJECTIONS

The results from these analyses are summarized in the one-line diagrams in Figure 10.1.

In the figures, voltages have been replaced by the aforementioned sensitivities (for this reason, any flow labels in the diagram should be disregarded, since their values are meaningless). Because the powerflow cannot accommodate negative entries, a factor of 100 was added to all sensitivities. For convenience, attached to this report are results in a tabular format. The color scale in the figure ranges from red for a sensitivity of 100, to deep blue for sensitivities of 70 and lower.

As shown in the attached spreadsheets, the Swing Bus 147750 exhibits in all cases a sensitivity of 100. This is expected. It means that if 100 MW were injected at that station, the swing bus output would decrease by essentially the same amount, and there would be no impact on losses. The sensitivity is therefore zero; 100 in the figures and spreadsheets.

On the other hand, if 100 MW were injected at, say, Canal 138 kV in Long Island (Bus 129483; Eastern-most Long Island Station in Figure 10.1) in the peak load (LD1) case, and generation at Niagara were to be reduced accordingly (swing bus), NYISO losses would be reduced by 16.944 MW; hence an entry of 83.056 is indicated at Canal in Figure 10.1/LD1 (light green) and the attached corresponding spreadsheet. If the same 100 MW were injected in Case LD7 instead (least load), the loss reduction is lower (10.918, due to lower transfer levels), and hence the 89.082 entry (and yellowish tone) in that case.

These results can be verified manually in the cases provided by a) switching the swing bus to that of the Niagara station, b) turning off the SVCs at Fraser and Leeds and the STATCOM at Marcy, c) netting-out NYISO generators with reactive output either on maximum limit or in excess of 0.2 times the respective MVA base, d) injecting appropriate amounts of MW at the bus of interest, and e) resolving the powerflow with all automatic controls (transformers, phase shifters, and switched shunts) disabled. The difference in NYCA losses between the original and revised powerflow solutions, divided by the size of the MW injection assumed is the loss sensitivity at the bus in question.

For example, injection of 10 MW at Canal 138 kV (negative 10 MW load) in the LD1 case leads to a reduction in generation at the swing bus Niagara unit from 194.2 MW to 182.1 MW; i.e., a 2.1 MW reduction in system losses. The reduction in NYCA losses (Areas 1 through 11), on the other hand, is of 1.7 MW; very much in line with the associated (83.056) sensitivity.

In summary, the “bluer” the buses in Figure 10.1 are, the higher the reductions in NYISO losses as a consequence of MW injections are expected to be.

The results suggest, as expected, a significant reduction in losses (15% to 20% of every MW injected at higher load levels) when additional generation is dispatched (or load is reduced) in the higher load cases in the New York City and Long Island areas at the expense of generation in the Niagara area. Only in the lighter load LD6 and LD7 cases does the incentive (loss-wise) for generation (and/or load management) in these areas subside.

Reductions in losses will also be observed (although less dramatic) when offsetting active power injections with reduced generation at any bus with a “redder” tone, i.e., a higher sensitivity number. For example, if the 100 MW injection at Canal at peak load (LD1 case) were to be accompanied with a 100 MW generation reduction at, say, Bethlehem (Bus 137711, Sensitivity of 92.013), the reduction in New York losses would be in the order of 9% instead of 17%.

Other “pockets” of opportunities for reductions in losses by active power injection are suggested in the figure. These correspond mainly to radial loads at, for example, the Brothertown Road (Oneida County), and Sanford Lake or Barton Brook in Essex County Substations. Although incrementally they may exhibit in the figure and attached spreadsheets potentially higher loss reduction opportunities than in the New York City and Long Island systems, their aggregate potential is of course negligible compared to that in the latter two.

The results also allow comparison of the impact on losses from generation at alternative power plants. For example, active power sensitivities in the Oswego area are in the order of 97 to 94 across the LD1 and LD2 levels (i.e., a 3%-6% reduction in losses when generating there as opposed to at Niagara). They are in the order of 98 to 96% in the vicinity of the Moses plant.

Sorting the attached spreadsheets by sensitivity in an ascending order will display some very low sensitivity values; the lowest (in the LD1 case) being a sensitivity of 17.7 at Bus 131815

(Harris 34, 34.5 kV). This implies that a 1 MW injection at that bus would lead to a similar (0.823 MW) reduction in losses. These are all medium voltage buses, connected over high-resistance transmission.

10.4 Sensitivity to Reactive Power Injections

The impact on losses of reactive power injections (switching-in of a capacitor, or switching-off of a reactor, for example) is illustrated in Figure 10.2.

It is important to note in these figures the fact that the color scale has been substantially reduced; from 70-100 MW in the previous set of figures (MW injections), to 97.5-102.5 MW in this set. This is in recognition of the fact that in general reactive power has less of an impact on active power losses than active power does.

It is also important to note that although as in the previous set of cases the swing bus was assigned to one of the Niagara units, the location of the swing bus is in these analyses much less important than in the active power injection analyses. This is because reactive effects are for the most part local in nature, as opposed to the significant effects on MW flows throughout the network that MW injections can have.

As in the previous set of figures, a constant factor of 100 was added to all sensitivities in order to allow their being displayed on “power flow” one-line diagrams.

The results should be interpreted as the impact a 100 Mvar injection at a particular bus would have on MW losses. For example, in Figure 10.2, for every 100 Mvars injected at the Montour Falls 115 kV Substation (Bus 130830, Central Zone, Schuyler County), NYISO losses would be reduced by 5.9 MW in the LD1 case (100-94.118 at Bus 130830 in the attached LD1 spreadsheet); and by 2.9 MW in the LD2 case.

Note that voltage regulating generation buses do not have sensitivity to reactive power injections, since they would be offset by the equipment controlling such buses’ voltages. Hence, if within reactive limits (which includes consideration of the maximum 0.98 pf assumption), they all exhibit a sensitivity of 100 in the attached spreadsheets (i.e., a situation akin to MW injections at the swing bus in the previous figure).

Thus, from the point of view of active power losses, “deep blue” buses in Figure 10.2 are good candidates for capacitor additions, whereas “red” buses are good candidates for the switching-in of reactors. Hence, in the LD1 case there is large swath extending through most of the Western and South Central parts of the state where reactive power injections might lead to substantial reductions in losses (e.g., 5.5%). At lower load levels, however, the benefits may be less pronounced; as suggested by the LD2 results (e.g., 2.3%).

Shown in Figure 10.3 is a repeat of the Figure 10.2 results for the LD1 and LD2 scenarios, but assuming higher reactive capability on generators (from 0.98 to 0.95 power factors, on their respective MVA Bases). Comparison of the two sets of results suggests that in the LD1 case, the significant sensitivites observed on Western and South Central parts of the state in Figure 10.2 are in part a consequence of generation being pegged at its 0.98 power factor limit. At the LD2 and lower voltage levels, however, generation reactive limits have much less of an impact.

For completeness, active power sensitivities with 0.95 power factor are displayed in Figure 10.4 (compare against their counterparts in Figure 10.1). As expected, the results suggest the assumed reactive capability on generators has minimal impact on active power sensitivities.

10.5 SUMMARY AND CAVEATS

It is important to note that the above "recommendations" for active and reactive power injections do not take into account voltage constraints, which could limit the operators' ability to switch in and out compensation at will. Some guidance as to what those constraints might be is provided in Figure 9.6, where per-unit voltage magnitudes are depicted for each of the seven load step cases using a color scale ranging from 0.95 (deep blue) to 1.05 (red) pu voltages. The figures display bulk transmission voltages only, however, whereas voltage criteria must be complied with across all voltage levels. Other constraints such as thermal limitations or interface limits may come into play too.

The interactions between losses, compensation, voltage and other constraints are complex, and further, involve the potential use of existing controls such as transformer taps, generator voltages and existing shunt compensation for loss reduction; controls that were assumed fixed in these analyses. For example, a bus with high sensitivity to reactive power injections but with voltage pegged at its high limit might still be able to benefit (from a losses point of view) from additional compensation if transformers can be used to redirect the extra reactive power to voltage levels where constraints are less of a concern and reactive injections are still beneficial for loss reduction. Because of their global control nature (as opposed to the local control approach in conventional power flow), OPFs are ideally suited to examine such interactions. In the next sections results from studies where the OPF was allowed to adjust some of those control variables are reported.

Notwithstanding the above, the sensitivity results in Figures 10.1 and 10.2 do provide valuable input as to opportunities for loss reduction. As will be reported later, results from analyses where voltage constraints are taken into account and transformers and other control variables are allowed to adjust are for the most part in line with the above sensitivities.

In addition to their use in a planning environment, OPF sensitivities could also play a valuable role in operations, by providing guidance as to directions in which the system could be taken to in order to reduce losses. This is not limited to active and reactive power injections. Transformers can be viewed as having the ability to "move" reactive power between different voltage levels (although potentially losing some of that reactive power in the process). Hence, a transformer connecting two buses with significantly different sensitivities to reactive power injections might be a candidate for adjustment in reducing losses. Likewise, phase shifters can affect the distribution of active power between systems. Hence, not withstanding the other objectives of phase shifters, such as managing thermal limitations, a phase shifter connected between systems with substantial differences in active power sensitivities could be adjusted in order to reduce losses, particularly if such adjustment is also in the direction for meeting its other objectives.

From a computational point of view, although, as explained above, sensitivities may also be calculated with repeated executions of conventional power flows, this is bound to be a time-consuming proposition, and potentially subject to significant innacuracies. This is particularly the case when considering weak buses where only minor MW or Mvar injections can be considered, and hence where the innacuracies inherent in the iterative nature of powerflow solutions can prevent the calculation of minor differences in MW losses between powerflow solutions.

Instead, in OPF solutions all sensitivities are automatically calculated at the same time, in one solution, and they are calculated algebraically, on the basis of elementary principles.of powerflow equations. Consequently they are much more accurate. *Note: this is a situation akin to that occurring in the small signal analysis of power system dynamics, where the algebraic* *calculation of state matrices leads to far more reliable results than through their estimation via perturbation analyses.*

For reference purposes, the analysis of each of the seven cases reported in this section took an average of 50 sec. of CPU time on a 2.39 GHz Intel Core Duo Laptop with 2 GBytes of Memory.

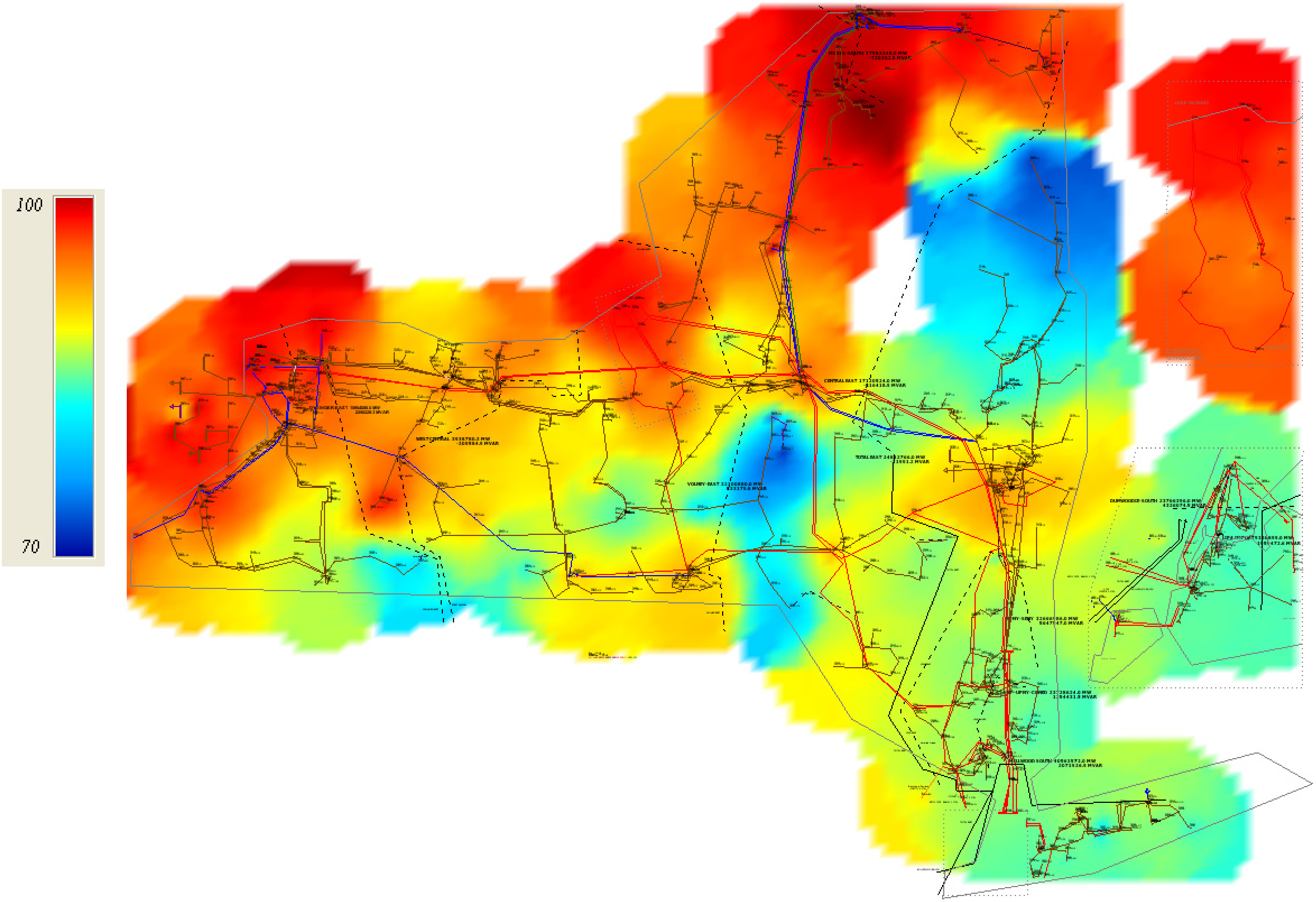


Figure 10.1 - Active Power Sensitivities – 70% to 100% Color Scale – LD1 Case

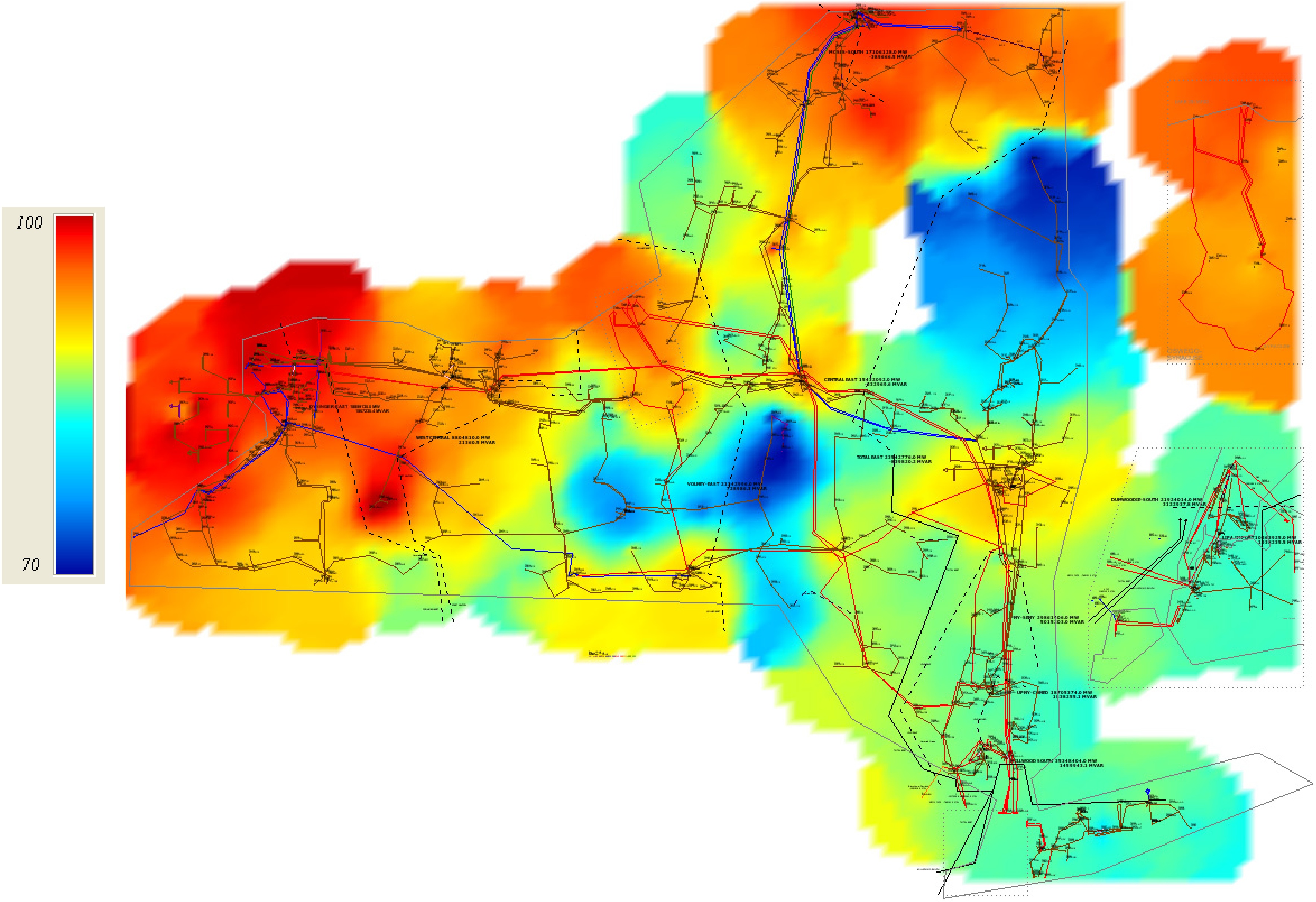


Figure 10.1 (Cont.) – LD2 Case

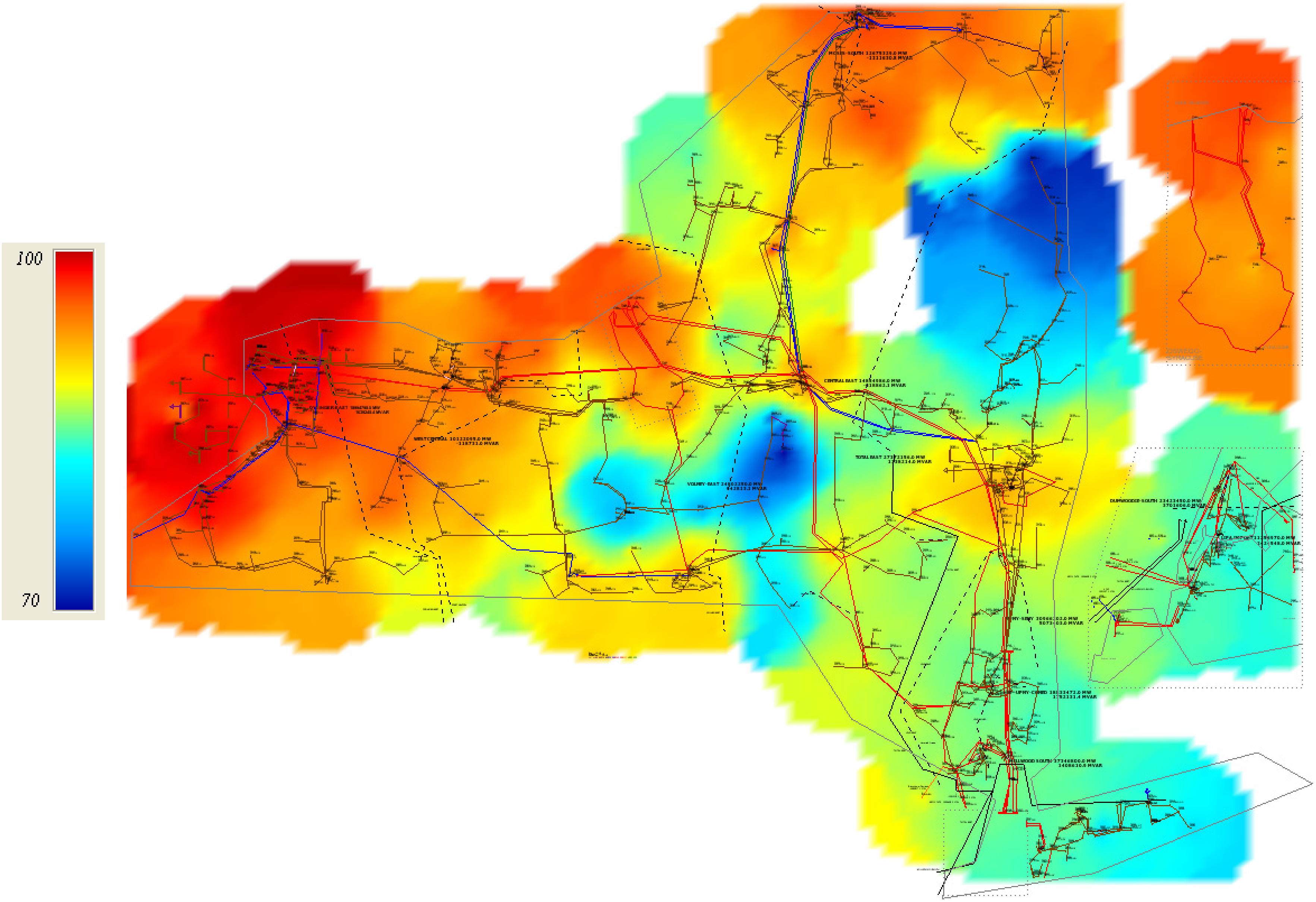


Figure 10.1 (Cont.) – LD3 Case

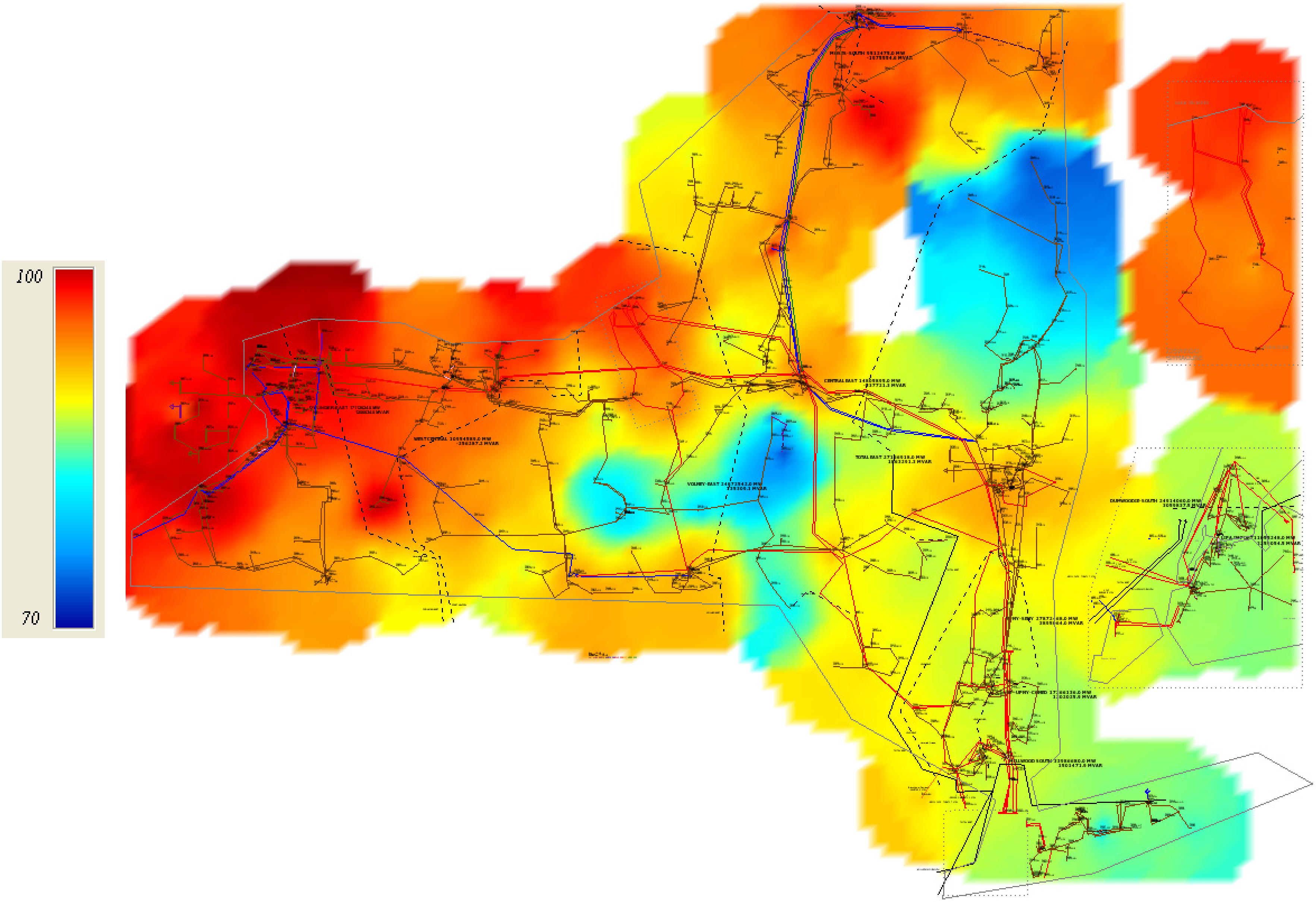


Figure 10.1 (Cont.) – LD4 Case

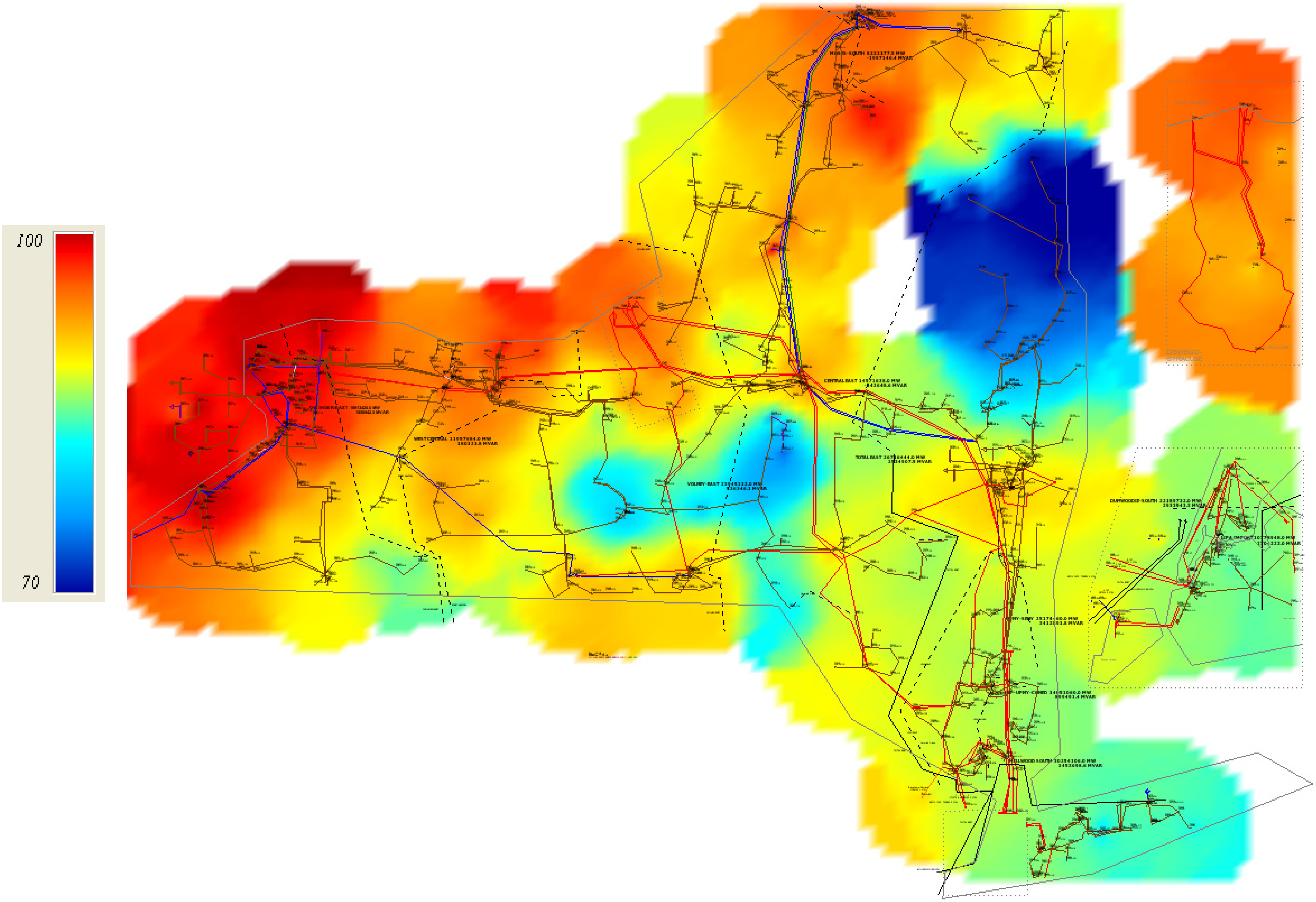


Figure 10.1 (Cont.) – LD5 Case

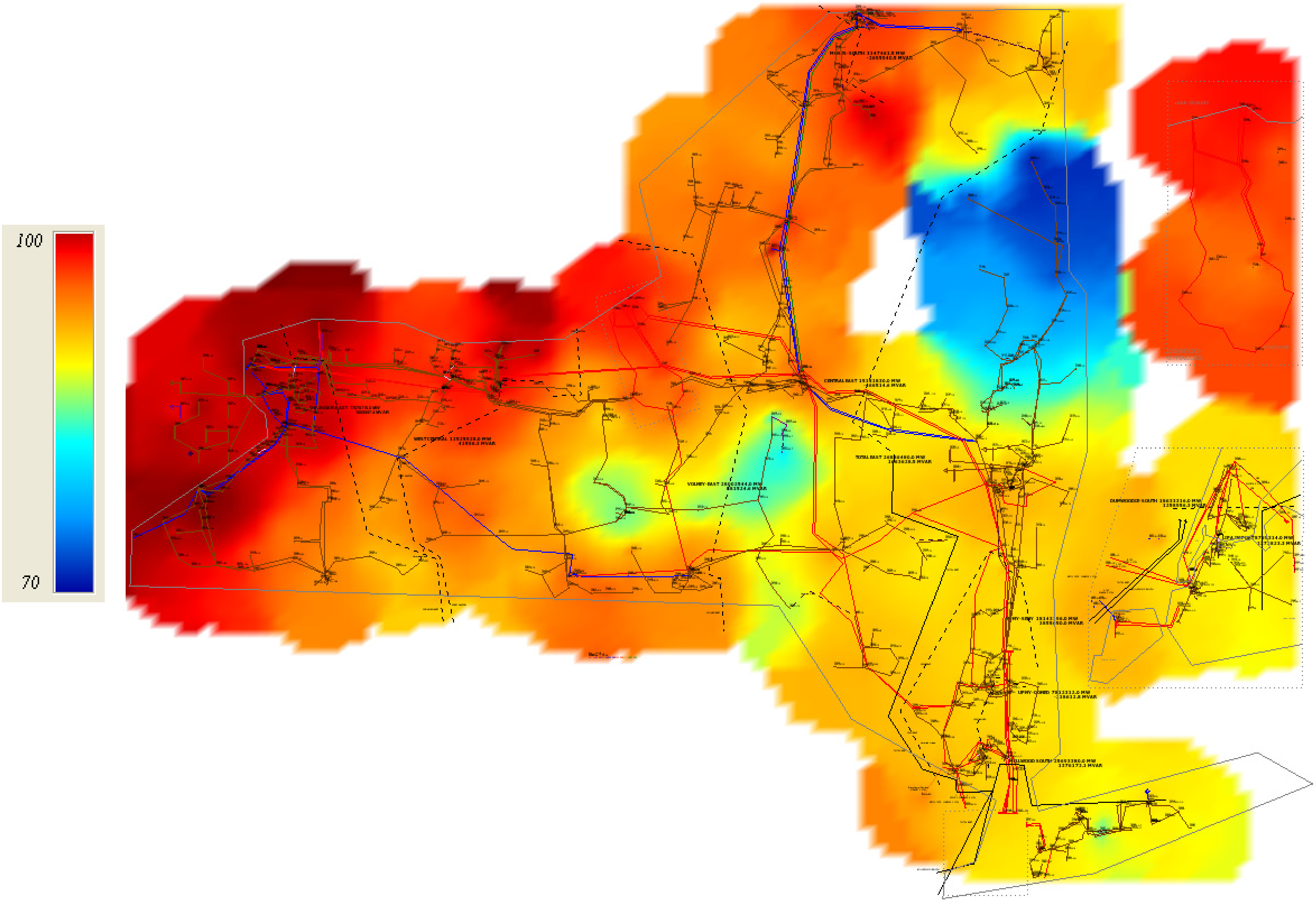


Figure 10.1 (Cont.) – LD6 Case