DRAFT
Proposal for ICAP Load Forecasting Process Improvements

The Load Forecasting Task Force met on April 9th to review the results of the 2003 ICAP Load Forecast and explore ways the process followed to produce it can be improved. This document summarizes those discussions and explains the remedies the LFTF developed. The ICAPWG is hereby requested to give these remedies its consideration and recommend to the approach it feels is best.

The 2003 ICAP Load Forecast

Final TD ICAP requirements were posted as follows:

2003 ICAP Requirements (May - April)

Transmission District	2003 Peak Load (M	TD Share	1) ICAP uirement (	Effective ICAP %	2) UCAP Requirement (MW)	Effective UCAP %
Central Hudson	1,134.0	0.037	1,356.5	119.62%	1,291.3	113.87%
Con Edison	12,650.0	0.408	15,132.1	119.62%	14,404.3	113.87%
LIPA	4,848.6	0.156	5,800.0	119.62%	5,521.0	113.87%
NMPC	6,468.6	0.209	7,737.9	119.62%	7,365.7	113.87%
NYPA	659.3	0.021	788.7	119.62%	750.7	113.87%
NYSEG	2,658.6	0.086	3,180.3	119.62%	3,027.3	113.87%
Orange and Rockland	1,000.0	0.032	1,196.2	119.62%	1,138.7	113.87%
RGE	1,584.8	0.051	1,895.8	119.62%	1,804.6	113.87%
Total	31,003.9	1.000	37,087.4		35,303.5	

Statewide requirements

NYCA ICAP Requirement set at 118% of 2003 forecast peak				
NYCA ICAP Requ	=	1.18 x	**31,430**	MW
	=	**37,087.4**	MW	
[1] Reduced by 435 MW to account for Rockland Electric Company load moving to PJ				
UCAP Calculation = 30,475 * 118% * (1-NYCA EFOR)				
NYCA EFOR	=	4.81%		
1-NYCA EFOR	=	95.19%		
NYCA UCAP Req	=	**112.32%**	**31,430.0**	MW
	=	**35,303.5**	MW	
ROS UCAP Deficiency Price		**267.89**	**/per year**	
ROS UCAP Deficiency Price		**22.32**	**/per month**	

Locational requirements

NYC ICAP requirement is 80% of peak load	
NYC UCAP requirement is the NYC peak load * (80% * (1- NYC EFOR))	
NYC EFOR =	5.21%
1 - NYC EFOR =	94.79%
NYC Peak Load =	11,020.0
NYC UCAP =	**8,356.7**
NYC UCAP Deficiency Price f	**503.22**
NYC UCAP Deficiency Price f	**41.93**

LI ICAP requirement is 93% of peak load	
LI UCAP requirement is the LI peak load * (95% * (1- LI EFOR))	
LI EFOR =	4.13%
1 - LI EFOR =	95.87%
LI Peak Load =	4,848.6
LI UCAP =	**4,415.9**
LI UCAP Deficiency Price	**434.96**
LI UCAP Deficiency Price	**36.25**

Market participants were disturbed that the Effective ICAP%, 119.62%, was greater than the Installed Reserve Margin set by the NYSRC, 118% of the forecasted peak. NYISO presented the reasons for this at the April 9 LFTF meeting. A summary table is presented below:

Reconciliation of TD Forecasts To NYCA Forecast		
NYCA Peak Forecast	31,430	MW
Sum of TD Forecasts	31,010	MW
Total Difference	420	MW
Weather Normalization	220	MW
Losses in NYCA, not TDs	570	MW
	790	MW
Unexplained Difference	**(370)**	MW

Staff's investigation revealed that the difference between the sum of the TD peak forecasts and the NYCA peak forecast, 420 MW, was explained by weather normalization practices (220 MW) and transmission loss reporting (570 MW) and if these two could be made to conform to a consistent reporting and accounting procedure, diversity of approximately 370 MW would be observed.

Proposed Remedies

The LFTF discussed several alternatives. One alternative consists of simple procedural changes. Another was offered in the form of a strawman and involved significant changes to the current process, but is still based on it. The third alternative is scrapping the current process entirely and replacing it with, for lack of a better term, a PJM-based model.

The features of each of these will be discussed in turn.

Alternative 1: Procedural Changes

This alternative involves relatively minor (when compared to the other two alternatives) changes to the process as it currently functions.

All TOs and MESs will report their hourly loads every quarter to ISO staff. Each TO will **report Native Load**, or total load net of transmission losses (or ISO staff will calculate Native Load by applying transmission loss factors to the total load). These loads will be **compared to TO loads ISO staff develops from its billing system** and any significant discrepancies identified. Transmission losses will be accumulated and reported as a separate category.

Currently TOs report hourly load once per year, transmission losses are not consistently handled, and the reported loads are not reconciled to those of the billing system.

Appendix A in the Load Forecasting Manual will address weather normalization only:

Appendix A

Load Forecast Reporting Timeline

Weather Normalization: NYCA and TO AAPLs	**2003 - 2004 Schedule**
NYISO releases preliminary date and level of 2003 NYCA Annual Adjust Peak Load (AAPL)	1-Oct
NYISO releases final EDRP and SCR Total Load MW to TOs	16-Oct
NYISO releases final date and level of 2003 NYCA AAPL	20-Oct
TOs provide AAPLs to NYISO Staff	23-Oct
TOs provide weather nomalization methodologies	23-Oct
MESs provide load at time of TO AAPLs to NYISO Staff	28-Oct
NYISO and TOs give presentations on weather normalizations at LFTF meeting	31-Oct
NYISO releases preliminary TD 2003 weather normalized peaks	5-Nov
Weather normalization comment period begins	6-Nov
Weather normalization comment period ends	7-Nov
Weather normaliztion dispute resolution period begins	10-Nov
Weather normaliztion dispute resolution period ends	10-Dec
NYISO releases final TD 2003 weather normalized peaks	12-Dec
TOs release LSE load coincident with AAPL to LSEs	30-Dec

This gives the determination of weather normalized peaks the same level of visibility that exists for that of the TO regional load growth factors (RLGFs). The presentation of weather normalization methodologies to all MPs by the TOs and NYISO staff and the ability of MPs to dispute them will expose and resolve any disagreements early in the ICAP load forecasting process. Separating this from the dispute resolution process available for RLGFs will delineate the separate role each of these play in determining TD and NYCA ICAP requirements and, it is hoped, remove the end results oriented questions that frequently arise now. (The current Appendix A will become Appendix B and is little changed.)

The separation of transmission losses from native load means that these will have to be accounted for explicitly in the ICAP load forecast. How this will be accomplished is shown in the following table.

Alternative 1
Hypothetical 2004 Example

	Actual Peak Load [1]	Date Of Occurrence	Hour (Beginning) Of Occurrence	Actual Adjusted Peak Load [2]	Allocated Transmission Losses	Final Adjusted Peak Load [3]
TO 1	13,700	15-Jul	16	13,930	212	14,142
TO 2	8,530	14-Jul	18	8,640	131	8,771
TO 3	4,470	5-Aug	14	4,420	67	4,487
TO 4	3,650	28-Jul	15	3,660	56	3,716
MES 1 (in TO 3 TD	180	5-Aug	14	183	3	186
MES 2 (in TO 4 TD)	90	28-Jul	15	87	1	88
Subtotal	30,620			30,920	470	31,390
Total Transmission Losses not Included	470	-	-	470	-	-
	31,090			31,390	470	31,390
NYISO	31,050	14-Jul	15	31,330	-	31,330

1 Highest actual TO hourly load experienced, including all losses except Transmission losses.

2 Highest actual TO hourly load experienced, including all losses except Transmission losses, after adjustment for the following:
(i) Load relief measures such as voltage reduction and Load Shedding
(ii) reduction provided by Interruptible Load Resources
(iii) reduction provided by NYISO Emergency Demand Response Program and Special Case Resources
(iv) Station Power that is not being self-supplied
(v) Normalized design weather conditions

3 Final Adjusted Peak Load - AAPL plus the allocated portion of Transmission Losses

The Actual Peak Loads excluded a total of 470 MW of transmission losses. This is carried over to the Actual Adjusted Peak Load column. Transmission losses are allocated to TOs and MESs based on each ones share of the sum of the non-coincident AAPLs (30,920 MW). Thus, all requirements that incur ICAP are accounted for.

The purposes of the Alternative 1 are to make the weather normalization process more transparent and to ensure that transmission losses are fully and consistently accounted for. TOs still work with non-coincident AAPLs. These form the basis for the Final Adjusted Peak Loads, which will be the figures to which the RLGFs will apply. However, because TOs' AAPL will likely occur on different days, and the probability that some will reflect conditions more extreme than design ones and others will reflect less extreme ones, the possibility that weather normalization will introduce "negative diversity" cannot be excluded. As seen this year, about 220 MW of diversity was "lost" because of this situation.

Alternative 2: Shares of NYCA AAPL Strawman

The concepts behind Alternative 2 are illustrated in the following table:

Share of NYCA AAPL Strawman
Hypothetical 2004 Example

NYCA Peak Day:	17-Jul		Actual		Final	
NYCA Peak Hour:	HB 4:00:00 PM		Adjusted		Adjusted	
	Native Load [1]	Shares	Native Load [2]	Shares	Native Load [3]	Shares
TO 1	13,700	44.07%	13,930	44.29%	14,169	45.05%
TO 2	8,530	27.44%	8,640	27.47%	8,788	27.94%
TO 3	4,470	14.38%	4,420	14.05%	4,496	14.29%
TO 4	3,650	11.74%	3,660	11.64%	3,723	11.84%
MES 1	180	0.58%	183	0.58%	186	0.59%
MES 2	90	0.29%	87	0.28%	88	0.28%
Transmission Losses	400	1.29%	400	1.27%	-	0.00%
Unaccounted Load	70	0.23%	130	0.41%	-	0.00%
NYCA Peak	31,090	100.00%	31,450	100.00%	31,450	100.00%

1 Native Load - TO or MES actual integrated hourly load including all losses except Transmission losses.

2 Actual Adjusted Native Load - Total Load adjusted to reflect:
(i) Load relief measures such as voltage reduction and Load Shedding
(ii) reduction provided by Interruptible Load Resources
(iii) reduction provided by NYISO Emergency Demand Response Program and Special Case Resources
(iv) Station Power that is not being self-supplied
(v) Normalized design weather conditions

3 Final Adjusted Native Load - AANL plus the allocated portion of Unaccounted Load and the allocated portion of Transmission Losses

The difference between Alternatives 1 and 2 is that the latter, instead of basing TO weather normalization on non-coincident peaks, bases it on each TOs and MESs load at the time or the NYCA Peak. TO hourly loads are still collected quarterly and reconciled to billing load, and transmission losses are still accounted for separately.

In this example, another category of load is present: Unaccounted for load. This is the difference between the sum of the TO and MES load and transmission losses on the one hand and the NYCA load on the other. Above, the NYCA load is 70 MW greater than what is accounted for by TO and MES load and Transmission Losses.

TOs again do their own weather normalizations as does the NYISO. The result is the Actual Adjusted Native Load column. Unaccounted Load has grown to 130 MW, the result of the NYCA load being adjusted up 360 MW and the TO and MES load being adjusted up only 300 MW, and additional 60 MW difference.

The Final Adjusted Total Load shows each TO and MES absorbing Transmission Losses and Unaccounted Load in proportion to its contribution to the sum of TO and MES loads.

Like Alternative 1, Alternative 2 explicitly accounts for Transmission Losses. In addition, because all entities are performing their weather normalizations on a load that occurs at the same time, it is much less likely that some will be adjusting upward while other are adjusting downward. Also, the Unaccounted Load will absorb any net divergence in adjustment, allocate them back to the TO and MES loads, and ensure that the ICAP obligation for it is accounted for.

Because each TO and MES Final Adjusted Total Load will probably be less that its actual peak load, applying an IRM to the NYCA forecasted peak will translate into effective IRMs that are less than that for NYCA in total.

Alternative 3: PJM-Based Methodology

The PJM methodology is similar to Alternative 2 in that it is based on TO load at the time of the control area peak. There are significant differences, however. The PJM methodology is outlined below.

1. PJM staff forecasts the RTO peak based on a projection of overall economic growth in the RTO
2. TOs shares of the historical RTO peak are actually the average of their shares of the year's five highest daily peaks (after adding back in the effect of load reduction programs)
3. Shares of forecasted peak are calculated as follows:
    a. Find the 5 year average of the TO shares as calculated in 2. (e.g., average for 1998 – 2002)
    b. Find the trend extrapolation of the five year series used to calculate the average in 3.a.
    c. The average of 3.a. and 3.b. is each TOs share of the forecasted PJM peak
4. Apply the shares calculated in 3.to the PJM forecasted peak to forecast each TOs load at the time of the projected RTO peak
5. Multiply the contribution of each TO to the forecast PJM peak as calculated in 4. by (1+required IRM) to determine each TO ICAP requirement

The LFTF suggested possible modifications to this approach:

1. Instead of forecasting the control area peak in total, forecast it for each TD
2. Base shares of the last actual peak on individual TD weather normalizations instead of sharing proportionately in the normalization of the control area peak

Either or both of these is possible and would not change the important features that distinguish the PJM methodology from the NYISO's:

1. The forecast is done by ISO staff instead of TO staff
2. It is based on TO contributions to the control area peak instead of TO non-coincident peaks.

The PJM Load Analysis Subcommittee oversees the ICAP forecasting process, but final determination of the assumptions and forecast is vested in PJM staff.

Further Action

ICAPWG approval is needed for changes to the ICAP load forecasting process, except for the relatively minor ones. The LFTF has identified those and will implement them. More significant changes, such as the those presented in alternatives 2 and 3, require ICAPWG approval to proceed further. Both of those alternatives have support on the LFTF.

The LFTF requests the ICAPWG to consider those alternatives and modifications to them that appear desirable and would appreciate the opportunity to answer related questions at an upcoming ICAPWG meeting.