TRANSMISSION & DISTRIBUTION PLANNING CRITERIA & GUIDELINES

Long Island Power Authority

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I. Introduction

This document provides a description of the Long Island Power Authority's (LIPA) Transmission and Distribution (T&D) systems and describes the planning criteria and guidelines followed in the development of the LIPA T&D system. The material contained in this document is consistent with prevalent utility practice, and reflects the best-in-class practices exhibited throughout North America. As a load serving entity and transmission owner within the State of New York and the member of the New York Independent System Operator (NYISO), New England Independent System Operator (ISO-NE), and PJM, LIPA adheres as a minimum to the standards and criteria of the North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council (NPCC), the New York State Reliability Council (NYSRC), the NYISO, ISO-NE, and PJM.

II. Document Review and Update Process

This document will be reviewed and revised as often as required to reflect any major standard and/or criteria changes made by NERC, NPCC, NYSRC, NYISO, ISO-NE, PJM or LIPA. A thorough review of the document is conducted every odd year beginning in September 2009 with completion and issuance of the revised document to LIPA targeted by the end of the following February.

A. *Major Revision History*

Revision Number	Summary of Modifications	Date Approved by LIPA
0	Initial Release	May 2004
1	Reflect Updated Criteria, Standards and Information	March 11,2008
2	Update Power Factor Criteria	December 15, 2009
3	Reflect Updated Criteria	September 20, 2010

B. Review Process - Responsible Organizations

The following LIPA organizations will participate in the document review process:

1. *T&D Manager's Network Asset Planning* (NAP) initiates the review and coordinates the review and update process. *Electric System Planning* will also analyze the electric system reliability impact and coordinate economic analysis of the proposed changes.
2. *T&D Manager's Network System Engineering* (NSE) will conduct a technical analysis of proposed changes to ensure that prevalent utility engineering practices are being followed.
3. *T&D Manager's System Operations* (SO) will assess impact of proposed changes on customer service and on the operation of the electric system.
4. *LIPA's T & D Operations and Power Markets Staff* will conduct an independent assessment of the proposed changes and jointly with *Electric System Planning* will coordinate the document approval process.

C. Approval Process

Upon completion of the review by the organizations listed in Section II.2 above, the revised document will be circulated for approval by the following organizations:

1. T&D Planning Coordinating Committee (TDPCC)
2. Senior Management in the Electric T&D Manager's organization

Final modifications to the document shall be completed during the last week of the following February for approval by the following LIPA organizations:

3. Senior Management - LIPA T&D Operations
4. Senior Management - LIPA Power Markets

D. DISTRIBUTION OF THE UPDATED DOCUMENT

Once the approval process is complete, the updated document is published on the LIPA Web site and copies issued to the NYISO, ISO-NE, PJM and FERC in accordance with the 715 Filing requirements. The latest changes will be clearly marked on each page at the margin. The date of each revision will be noted on the cover page of the document for historical reference.

III. Description of the LIPA Transmission and Distribution System

The electric transmission system is designed to provide adequate capacity between generation sources and load centers at reasonable cost with minimum impact on the environment.

LIPA's transmission and sub-transmission lines deliver power to its electric system for. 1.1 million customers in Nassau and Suffolk counties and the Rockaway Peninsula in Queens County. As defined by the New York Independent System Operator (NYISO)[1], "bulk" transmission includes LIPA's 345 kV and 138 kV systems: and, LIPA's sub-transmission includes the 69 kV, 33 kV and 23 kV systems. A geographic one-line is included in Exhibit 1. Each system has circuits constructed overhead, underground and underwater. In addition, LIPA electric system has five standard alternating current (AC) and two High Voltage Direct Current (HVDC) interconnections to neighboring electric systems, shown in Table 1

A. Internal Transmission Interfaces

The Long Island load center is defined as the Eastern Nassau and Western Suffolk area bounded by the Newbridge and Holbrook interfaces, where close to 50% of the LIPA system load is located. Noteworthy in this definition is the substation loads along the Route 110 corridor, in the Brentwood and in the Hauppauge Industrial Park area. Interface exports and imports are defined relative to the flow of energy to and from the load center (interface export is the flow into the load center; interface import is a flow out of the load center). The primary path for bulk power deliveries to LIPA's load center is across three internal bulk transmission interfaces: Newbridge Road, Northport and Holbrook (Exhibit 2). These paths are used to deliver power from LIPA interconnections

[1] NYISO Transmission and Dispatching Operations Manual Attachment A.1 and A.2 (Rev2.1, 9/4/08)

(off-Island sources) and major generating facilities at Northport, Barrett, Far Rockaway, Glenwood, Port Jefferson, Holtsville, Caithness, and Shoreham/Wading River to the LIPA load center.

These interfaces are important for analytical purposes in determining the ability to deliver generating capacity across the LIPA system. All generation on Long Island meets LIPA's deliverability standard[2] and currently there are no capacity constraints across any of these interfaces.

1. Newbridge Interface

The Newbridge interface is defined by an imaginary north-south line running just west of the Syosset, Newbridge Road and Bellmore substations. It is used to define the amount of power from western Long Island generators and imports over the Consolidated Edison Company of New York (Con Edison) ties that can be delivered to the LIPA load center in the Eastern Nassau/ Western Suffolk region.

The Newbridge interface is defined by five (5) 138 kV circuits.

- East Garden City - Newbridge Road (138–462)
- East Garden City - Newbridge Road (138-463)
- East Garden City - Newbridge Road (138-465)
- Freeport - Newbridge Road (138-461)
- East Garden City - Newbridge Road (138-467)

Besides these five 138 kV circuits, the following 69 kV and 33 kV circuits are also included in this interface:

[2] See Section V-J Generation Deliverability Criteria

- Mitchell Gardens – Newbridge Road (69-475);
- Meadowbrook – Newbridge Road (69-466);
- Oyster Bay – Syosset (69-533);
- Jericho – Newbridge (69-474);
- Baldwin – Bellmore (69-459);
- Roosevelt – Bellmore (33-421);
- Meadowbrook – Bellmore (33-432 & 33-433); and
- Merrick – Bellmore (33-417).

2. Northport Interface

The Northport interface is used to define the amount of power from the Northport Power Station and imports over the interconnection to New England (Northeast Utilities) that can be delivered to the LIPA system in Suffolk County. Five 138 kV underground circuits limit the transfer across this interface, two going to the Elwood substation and three going to the Pilgrim substation. Included in this interface are the following transmission circuits:

- Northport – Pilgrim (138-677 A&B);
- Northport – Pilgrim (138-679 A&B);
- Northport – Pilgrim (138-672);
- Northport – Elwood (138-678 A&B); and
- Northport – Elwood (138-681 A&B).

The dielectric filled Northport to Norwalk Harbor 1385 cable was replaced in 2008 by new solid dielectric cables 601, 602, 603. The new set of cables, Northport Norwalk Harbor Cable (NNC) is rated at 450 MVA; however the normal rating is currently limited to the prior 1385's rating of 286 MW. System conditions in Connecticut limit the normal import capability of this cable to approximately 200 MW with actual emergency support capability varying on a daily basis. Long Island constraints will limit import to approximately 200 MW with all Northport units at maximum output even if the limiting system conditions in New England are corrected.

3. Holbrook Interface

The Holbrook interface is the other major transmission interface on Long Island. It is used to define the amount of generation that can be delivered from generating sites located in the area east of a north-south imaginary line just west of the Port Jefferson, Holbrook and MacArthur substations. This would include the generation at Shoreham, Wading River, Port Jefferson, Holtsville, the East End gas turbines, and New York Power Authority's (NYPA) Flynn plant, as well as any power imported over Cross Sound Cable (CSC) HVDC tie at Shoreham.

Included in this interface are the following transmission and sub-transmission lines:

- Holbrook – Ronkonkoma (138-875);
- Holbrook – Ruland Road (138-882);
- Holtsville GT – Pilgrim (138-881);
- Pt Jefferson – Stony Brook (69-877);
- Holbrook - Nesconset (69-673);
- Holbrook – MacArthur (69-859);
- Holtsville GT– Patchogue (69-841); and
- Holbrook –Bohemia (69-775)

Exhibit 1 Long Island Geographic One-Line

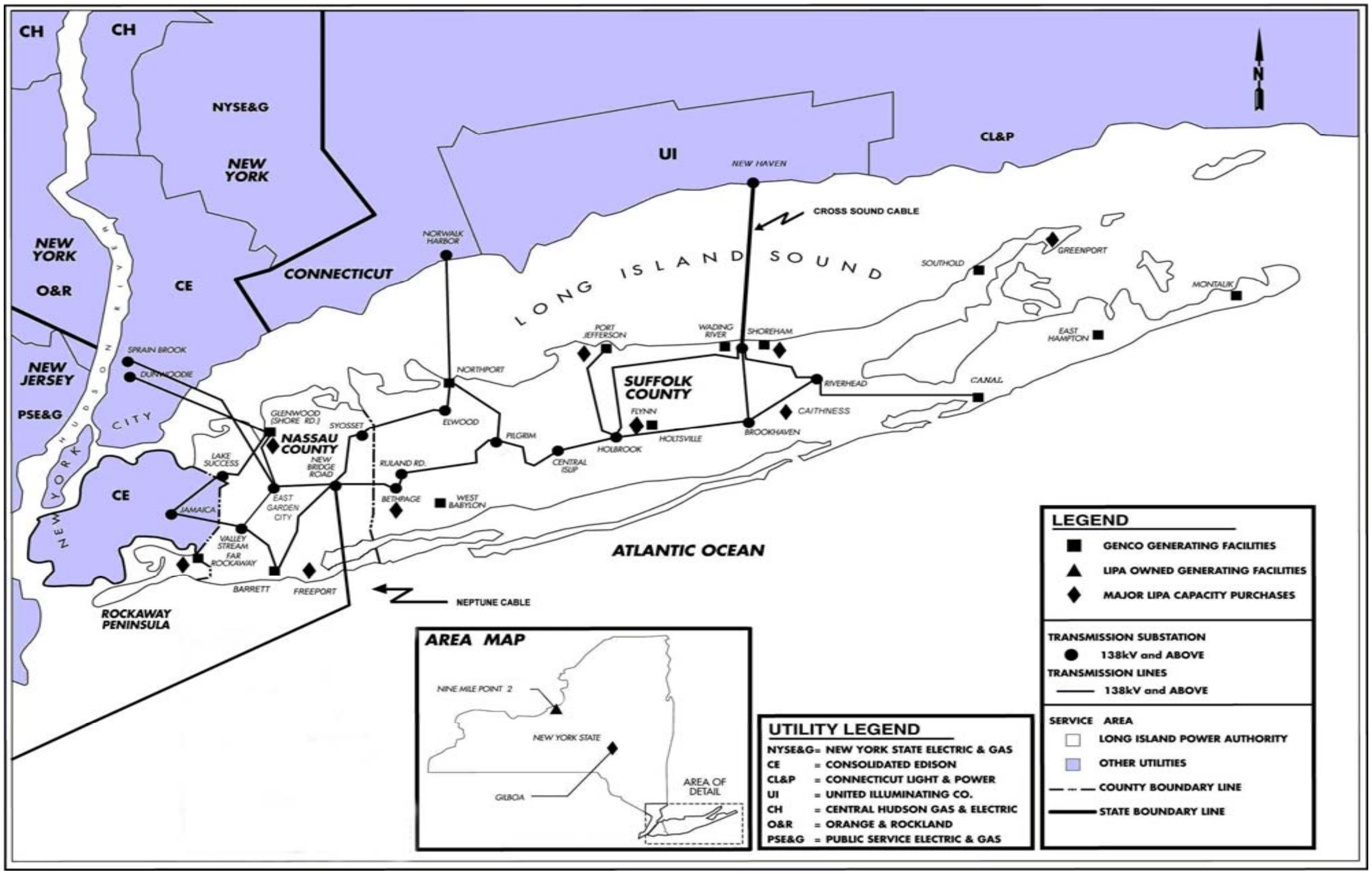
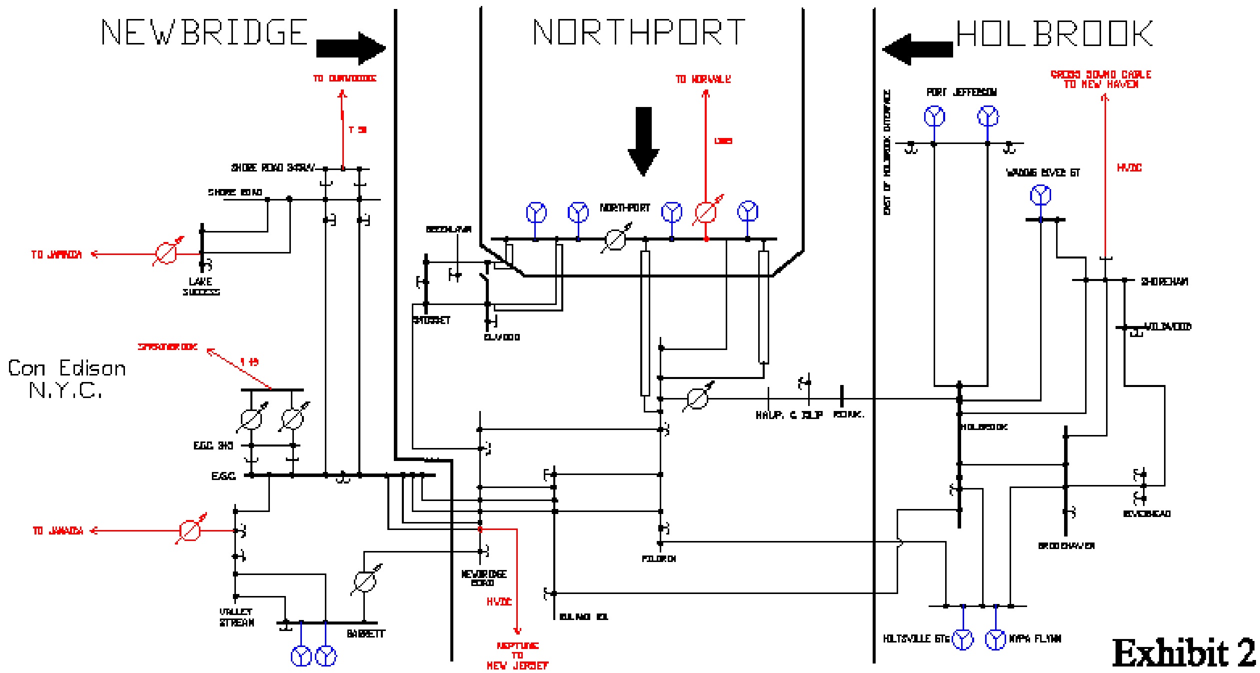


Exhibit 2 Transmission Interface



System Configuration

B. EXTERNAL TRANSMISSION INTERFACES

The LIPA electric system currently has two 345 kV and three 138 kV ac transmission interconnections and two high voltage direct current (HVDC) interconnections to neighboring systems in operation. The two 345 kV interconnections are used mainly to import power from the remainder of New York State to serve load requirements of LIPA, NYPA and Long Island municipalities. In addition, 286 MW of power is wheeled to Con Edison's Jamaica substation over the jointly owned Shore Road – Dunwoodie (Y50) interconnection.

Table 1 identifies the interconnections and their capabilities.

Table 1 Transmission Interconnections

Interconnection	To Company	Voltage (kV)	Rated Capacity (MW)
Shore Road - Dunwoodie (1) (Y50)	Con Edison	345 kV AC	653 (2)
E. Garden City – Sprainbrook (Y49)	NYPA-Con Edison	345 kV AC	637
Lake Success – Jamaica (1) (903)	Con Edison	138 kV AC	238
Valley Stream – Jamaica (1) (901)	Con Edison	138 kV AC	272
Northport Norwalk Harbor Cable (NNC: 601, 602, 603)	Northeast Utilities (NUSCO)	138 kV AC	286 (3)
Shoreham – East Shore (481)	United Illuminating	138 kV AC / 150 kV DC	330
Newbridge – Sayreville (500/ 501)	First Energy	345 kV AC / 500 kV DC	660

(1) Used to wheel 286 MW to Con Edison at Jamaica substation
(2) At 70%LF, limited to 415 MW cooling during next 12 hours
(3) NUSCO 1385 cable was replaced by NNC with a 450 MVA cable normal rated capacity value. It is currently limited to the prior cable's rating.

1. NYISO Transmission Interface

The NYISO Transmission interface is defined by the four (4) interconnections to the Con Edison system described in the above table:

- Shore Road – Dunwoodie 345 kV (Y50);
- East Garden City – Sprainbrook 345 kV (Y49);
- Lake Success – Jamaica (138-903)
- Valley Stream – Jamaica 138 kV (138-901).

2. ISO-NE – Transmission Interface

The ISO-NE interface is defined by the Northport – Norwalk Harbor Cable 138 kV cable (NNC), and the HVDC Cross Sound Cable (481) between Shoreham and East Shore in New Haven, Connecticut.

3. PJM – Transmission Interface

The PJM Interface is defined by the 660 MW high voltage direct current (HVDC) interconnection (Neptune RTS) from Raritan River, New Jersey to a converter station at Duffy Avenue, Hicksville, Long Island. From the Duffy Avenue station, the interconnection continues at 345 kV AC to Newbridge Road substation where it connects to the LIPA system. The Neptune RTS interconnection was placed into commercial operation at the end of June 2007.

4. Existing Third Party Long Term Contracts on External Interfaces

The Con Edison “wheel” contract is physically set by the LIPA System Operator in accordance with the terms of the Y50 contract. The NYPA contracts were converted to Transmission Congestion Contracts (TCCs) under the NYISO agreement and are managed by the NYISO.

5. Phase Angle Regulators for Power Flow Control

Phase angle regulators (PARs), also known as phase shifters, are used by LIPA to control the power flow on all but one of its external AC interconnections. Two 345 kV PARs control the power flow on circuit Y49. Similarly, two 138 kV PARs control the flow on circuits 901 and 903 to Con Edison’s Jamaica substation and a third PAR controls the flow on NNC circuits 601, 602, 603 to Norwalk Harbor (NUSCO). The Cross Sound Cable interconnection to New Haven, circuit 481, uses a voltage source inverter to control its flow. Neptune RTS uses insulated-gate bipolar transistors to control its flow. With all PARs in operation, Y50 carries the power difference between Long Island generation plus imports and the actual Long Island load.

In addition to external phase angle regulators, there are three PARs regulating internal power flow. Phase angle regulator at Barrett controls flow on the Barrett – Freeport – Newbridge Road 138 kV corridor. It is used to maximize exit capability out of Barrett power plant. The second internal phase angle regulator is a bus-tie PAR device located at Northport. It is utilized to maximize exit capability of the Northport power plant. The third phase angle regulator is located at Pilgrim. It is primarily used to optimize east to west and west to east power flows across the Holbrook interface.

C. Bulk Transmission Definitions

The definition of bulk transmission is a controversial issue with multiple definitions, e.g., Bulk Power System (BPS) and Bulk Electric System (BES), by various agencies. In general, it reflects larger (e.g., higher capacity, voltages) transmission and generation facilities that have transmit power across regions. The following paragraphs describe the various definitions used in the industry and how they relate to LIPA.

1. NPCC

The NPCC, which the NYISO is in, defines the Bulk Power System (BPS) as:

> "The interconnected electrical systems within north-eastern North America comprising generation and transmission facilities on which faults or disturbances can have a significant adverse impact outside of the local area. In this context, local areas are determined by Council members."

Presently, the NPCC determines BPS facilities based on the NPCC's Document A-10 "Classification of Bulk Power System Elements". This criterion is based on a functional test for significant adverse impact.

Based on that criteria there are two circuits in LIPA area that are designated as BPS facilities for the NYISO:

- Shore Road – Dunwoodie 345 kV (Y50): Joint ownership with Con Ed, and
- East Garden City – Sprainbrook 345 kV (Y49): Owned by NYPA

The NYISO and NPCC, have submitted the BPS facilities to NERC for designation as BES facilities as discussed in the following section. For those facilities designated as BPS, the NPCC applies more stringent criteria including additional control and protections above current NERC requirements for BES facilities, given the facilities importance to the region.

In addition to the BPS facilities, the NYISO also monitors certain 345 and 138 kV facilities on the LIPA system as part of its security constrained dispatch.

2. NERC

NERC's definition of the Bulk Electrical System (BES) is as follows: As defined by the *Regional Reliability Organization (e.g., NPCC),* the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition. The NPCC (and NYISO) designates its BPS list of facilities as BES facilities for NERC purposes.

In 2008, FERC expressed concerned about inconsistency of identified "bulk" facilities within NPCC (U.S.) region. It was noted that other NERC Regional Entities utilize bright line "BES" definition that is simply based on including 100kV and above facilitates, "bright line" determination, irrespective of their functional value. In response to the FERC December 18, 2008 Order on the issue, NPCC assessed the financial and reliability impacts of adopting the bright line method and supported the use of the more stringent regional NPCC BPS design & operation criteria for the NPCC region.

3. LIPA

For LIPA's own analyses, LIPA segregates its transmission system into "bulk transmission" (BTS) and sub-transmission systems. LIPA's bulk transmission is defined by LIPA as it's interconnections with its neighboring systems and on-Long Island 345 kV and 138 kV transmission circuits. On Long Island, all 345 kV circuits and, with very few exceptions, the 138 kV circuits are utilized strictly to transfer power across the LIPA system.[3]

D. *The LIPA Sub transmission System*

The LIPA sub-transmission system provides service to distribution substations. It consists of those parts of the system that are neither bulk transmission nor distribution, typically including voltages 69 kV and below.[4] In general, the sub-transmission system transfers power from the bulk transmission system to the various distribution substations. It also provides connection points to local 69 kV generation resources. Its design provides a highly reliable source of supply for these substations which typically serve approximately 10,000 customers per station.

In general, the sub-transmission system is designed in a closed loop arrangement originating from transmission substations that supply one or more distribution substations. Supervisory controlled circuit breakers and air break switches isolate faulted lines and restore service within a matter of seconds. The breakers at each end of a line may be line breakers, bus tie breakers, or part of ring bus, or breaker and half substation bus configurations.

E. *The LIPA Distribution System*

Distribution circuits originate at circuit breakers connected to the distribution substations in the system. The circuits are made up of main line conductors connected in an open loop arrangement to one or more adjacent circuits and branch line conductors that are connected to the main lines through fuses.

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[3] NYISO, NPCC, and NERC are presently reviewing definition of bulk transmission system.
[4] NYISO, NPCC, and NERC are presently reviewing definition of bulk transmission system.

The circuit mains have various sectionalizing devices to isolate faulted conductors and to facilitate the transfer of customers to adjacent circuits. These devices include, automatic sectionalizing units, automatic circuit reclosers, ground operated load break switches and stick operated load break disconnects. The primary circuit mains are generally designed to operate as part of a radial system but in specific instances, where a higher degree of reliability is desired; they are designed for automatic throw-over or network operation. Primary lines that branch off the mains are equipped with fuses at the point of connection to keep the mains in operation when branch line faults occur.

LIPA has two types of low voltage secondary network service. Area networks are supplied from two or more dedicated primary circuits with no other distribution load connected. Spot networks are normally supplied from two or more primary circuits that also supply other distribution load. Reference DA-56010 (Design of Secondary Networks) and OI-30002 (Operation of Secondary Networks).

F. TRANSMISSION AND DISTRIBUTION SUBSTATIONS

1. Transmission Substations

Predominantly, the electric substations in the LIPA system are distribution substations. With very few exceptions, the other substations in the system function as both transmission and distribution substations with distribution transformers connected to the 138 kV and 69 kV buses.

In general, LIPA's transmission substations receive power from the power system and step it down to lower voltages for further transmission to distribution substations through the sub-transmission system. The 345 kV and 138 kV circuits feed step-down transformers at these substations that in turn will feed 69 kV and 33 kV sub-transmission lines emanating from those substations.

The "I" bus design at these transmission substations (Exhibit 3) may be changed to either "ring" bus design (Exhibit 4) or "breaker-and-a-half" design (Exhibit 5) depending on the result of a reliability assessment[5] and physical property constraints. The 138 kV busses at the most critical substations in the bulk power system have already been converted to a ring bus, modified ring bus, or breaker-and-a-half designs. East Garden City presently has a ring bus design and plans are under considerations to modify the ring bus design into a figure eight, double ring bus design. Pilgrim currently is a figure eight, double ring bus design. Ruland Road and Newbridge Road have already been converted into a breaker-and-half bus design. The standard LIPA step-down transformer sizes are as follows:

Table 2 Step-down Transformers

VOLTAGE	CAPACITY	PHASING
345/138 kV (2)	450 MVA	Auto (Y GRND -Y GRND)
138/69 kV (1)	224 MVA or 110 MVA	Y GRND-Δ & Δ- Y GRND
138/33 kV	56 MVA	Δ-Y GRND
69/33 kV (2)	50 MVA or 25 MVA	Auto (Y GRND -Y GRND)

(1) There are two 50 MVA 138/69 kV transformers at Holbrook substation.
(2) East Garden City 345/138 kV & all 69/33 kV auto transformers have delta tertiary.

[5] See Section VI - Substation Design Criteria for further discussion

Exhibit 3 LIPA Bulk Transmission Substation Design "I" Bus Design Example of Three (3) Element System

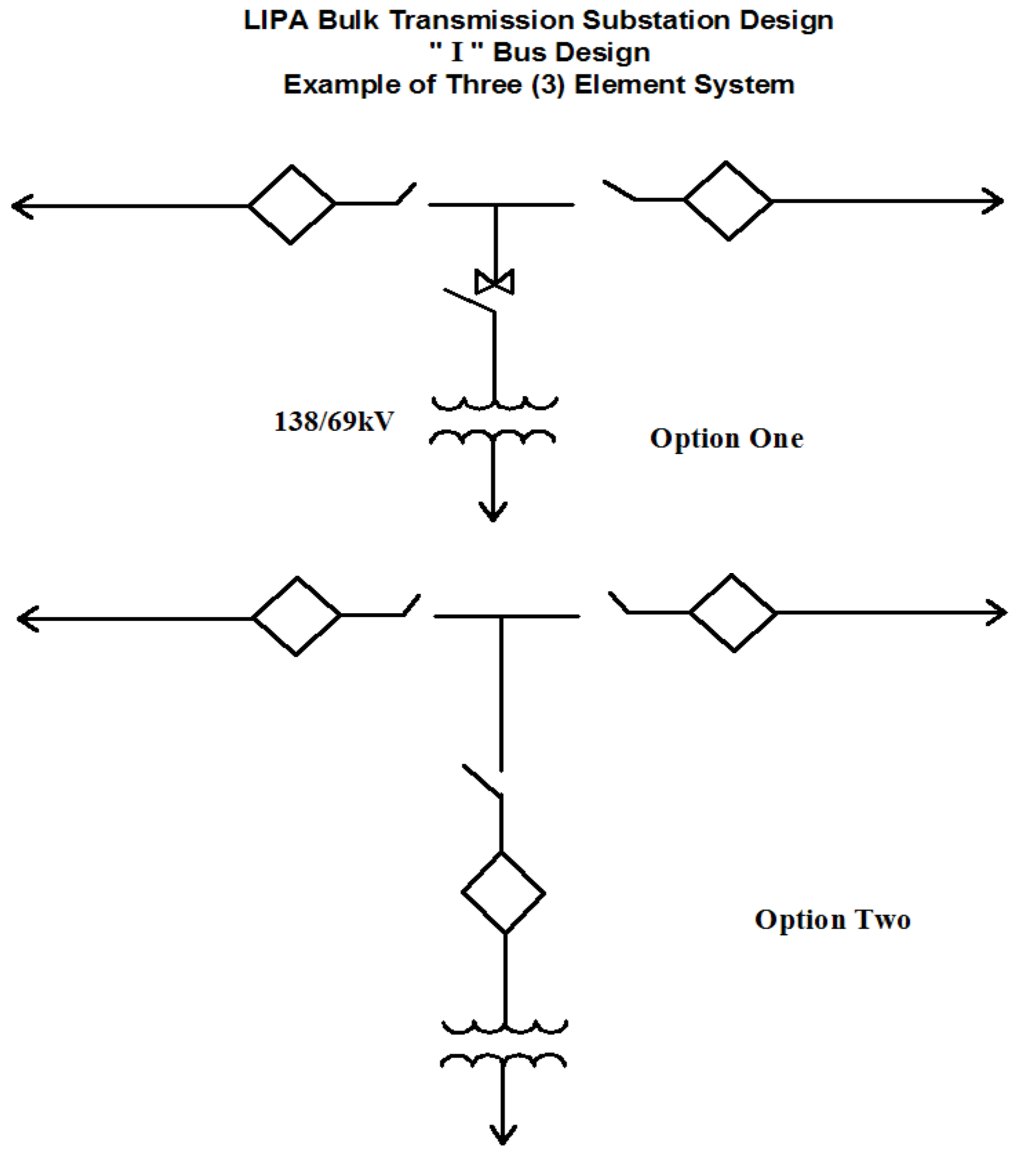
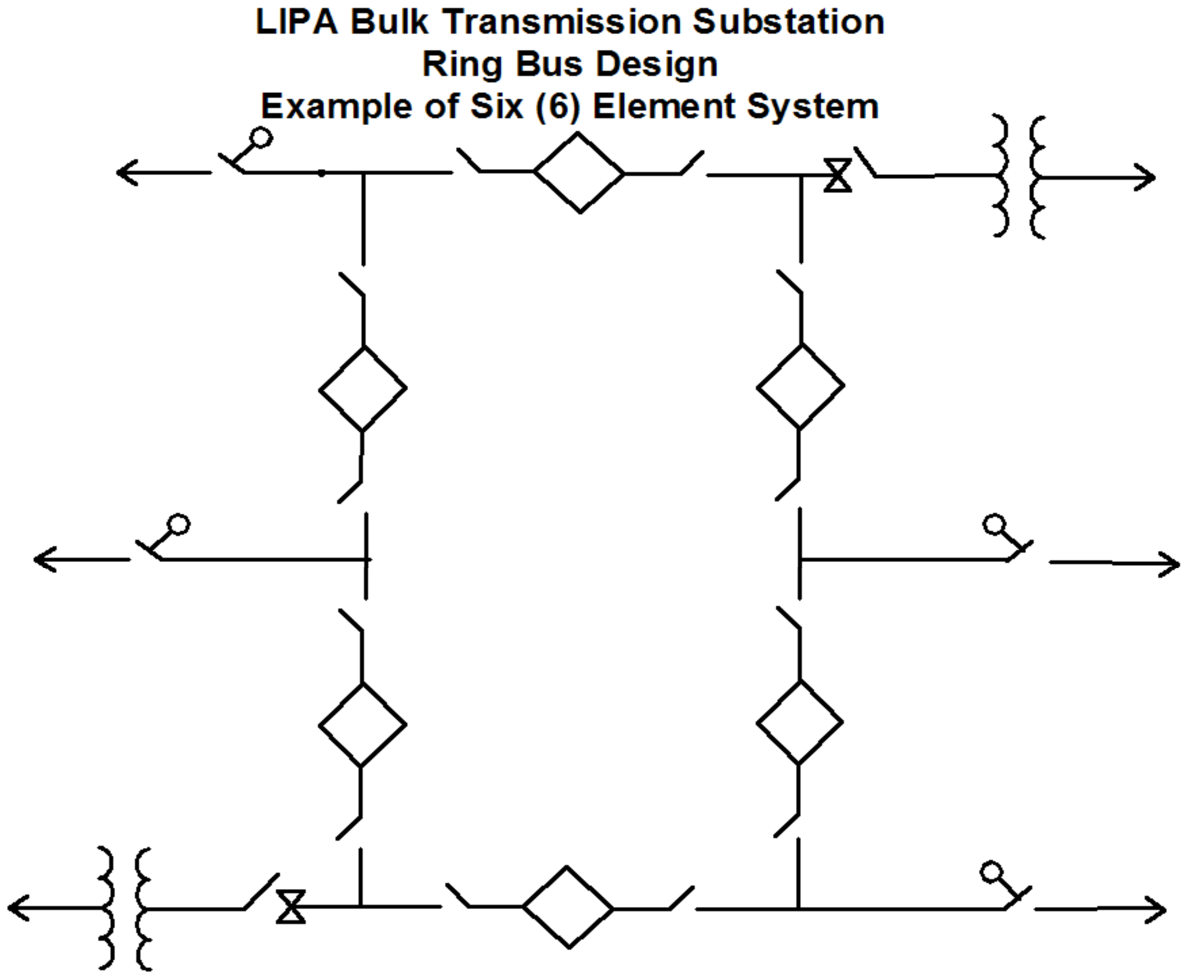
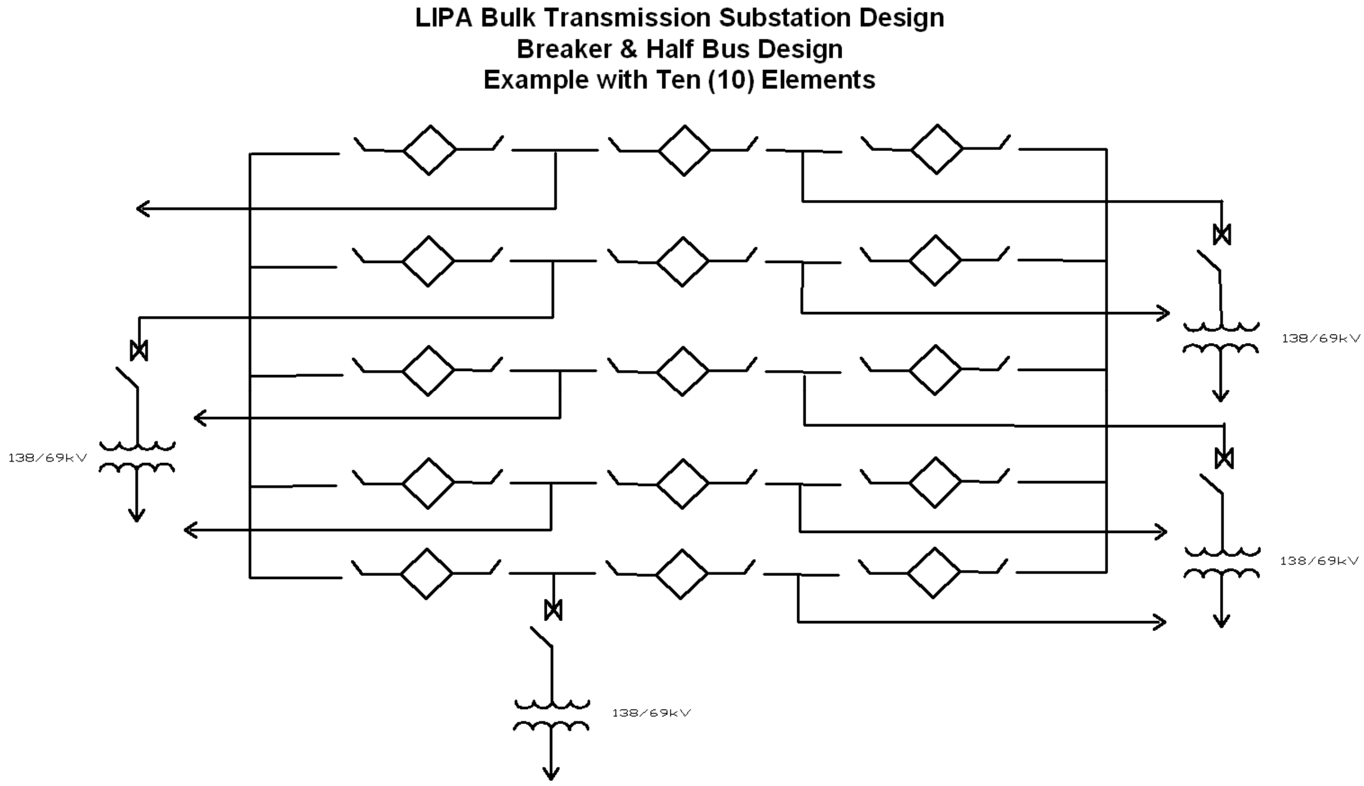


Exhibit 4 LIPA Bulk Transmission Substation Ring Bus Design Example of Six (6) Element System



Note: Separate "Like - Type" infrastructure.
(No two (2) banks or lines from or going to the same substation next to each other.)

Exhibit 5 LIPA Bulk Transmission Substation Breaker & Half Bus Design Example with Ten (10) Elements



2. Distribution Substations

Most distribution substations are connected in a closed loop arrangement originating from transmission substations that supply one or more distribution substations in the loop. This closed loop two transformer design was the standard supply to LIPA distribution substations. In general, a bus tie breaker design was used at distribution substations where two equally sized transformers share the load. In the event of a transmission line outage, the high-side breaker trip takes one transformer out of service temporarily until supervisory controlled switching can isolate the faulted line. Supervisory controlled circuit breakers and air break switches are used to isolate faulted transmission lines. The intent has been to convert these stations to a ring bus design in conjunction with overall system reinforcement projects; space permitting and when reliability can be improved.

Some radial substations have automatic or supervisory controlled throw-over schemes to an alternate supply in the event of the loss of the main supply. Circuit breakers at each end of a line may be line breakers or bus tie breakers.

G. Electric System Planning Criteria and Methodology

1. Modeling Guidelines

The planning process for designing the T&D System begins with the load forecast. The load forecast at the system level is based on econometric models, and is developed on both a weather-normalized and weather-probabilistic basis. Load forecasts are also developed for specific load areas using system load data acquired by the Energy Management System (EMS) and other systems in T&D Manager's T&D Operations. Specific major known or planned load additions are also factored into the load forecast.

The resultant load forecasts are utilized in three types of planning studies which assess the ability of the T&D system to meet future customer load requirements. These are:

- Long-range transmission studies are completed for the 35 to 40 year forecast time frame to determine the underlying build out architecture and address the bulk transmission system (BTS) and the underlying sub-transmission system, which supplies substations. Individual transmission and distribution investment decisions are made on a shorter 5 to 20 year timeframe.
- Area studies are generally for a 3 to 10 year forecast time frame and address specific load areas, including the area transmission system, substations and distribution feeders.
- Interconnection studies are designed to determine the required interconnection facilities and system reinforcements required for specific generation and transmission projects to enable them to be effective over the life of the project.

In these studies, the LIPA T&D system is modeled for a "peak hour" load level that has a 50% probability of occurrence (used for thermal assessment) and a 5% probability of occurrence (used for voltage assessment). Substation MW and MVAR "coincident peak" load levels are forecasted at the high side of the substation distribution transformer Generation schedule is based on economic dispatch and Independent Power Producer (IPP) resources available. Interconnection imports and power wheel to Con Ed are based on capacity or wheeling agreements.

Load flow analyses studies are used to determine expected circuit overloads and to evaluate alternatives for system reinforcements based on the results of the load flows. These studies are discussed in more detail in Section V of this document. These studies enable the T&D Manager to recommend the most appropriate, cost effective projects to meet system needs. Section XI details all computer modeling tools used in these studies.

Substation 345 kV, 138 kV, 69 kV, 33 kV and 23 kV circuit breakers are modeled using their rated interrupting capability in the ASPEN™ short circuit analysis computer program. Any breaker that meets or exceeds its rated interrupting capability is flagged for replacement. Section *V.G – Fault Current Calculations* gives a detailed explanation of the methodology used in the analysis.

2. Local Reliability Rules

Guideline for Running Northport Units on Gas

NYSRC IR-5[6] governs the loss of gas supply which is considered a single contingency that impacts the LIPA electric system. One or more Northport units may be required to utilize oil as the primary fuel such that the unit(s) will not trip on a loss of gas. Actual number of units burning oil will be dependent on the load level and voltage support devices in service. As such, system planning studies evaluate the limitations related to the use of gas at Northport.

H ELECTRIC RESOURCE PLAN

LIPA's Electric Resource Plan incorporates recommendations from several interdependent plans including: the Environmental Plan which addresses environmental issues that drive a significant part of the resource plan strategy; the Efficiency Plan which postpones the need for generation resources; the Transmission and Distribution Plan which supports system reliability and increases system efficiency; the Fuel

[6] NYSRC Reliability Rules For Planning and Operating the New York State Power System, http://nysrc.org

Management Plan which ensures a reliable supply of fuel; and, the overall Electric Resource Plan which combines the elements from all of the plans, in addition to the Power Supply Plan, into the final plan for meeting customer needs. The Electric Resource Plan recognizes and internalizes the importance of the environment within each and every strategic decision.

There are five key LIPA strategic objectives: supporting a healthy environment, cost, supply reliability, service reliability, and flexibility which drive the component plans that make up the Electric Resource Plan and support the development of recommended actions. These four strategies (energy efficiency, renewable resources, upgrade the existing fleet, and improve interconnections and reliability) were developed to support the organization's objectives and as such drive the recommended actions in the Electric Resource Plan, of which the T&D Plan is an element. In the T&D plan, recommendations are developed, which include continued investment in efficiency as a means to postpone the need for new generation, mitigate environmental issues and mitigate long term supply risk. These plans are developed using probabilistic models and ranked accordingly.

Programs are also advanced ahead of need to capture additional loss savings; and evaluations of transformer purchases, both substation and distribution banks, are evaluated on a total cost of ownership basis that includes lifetime benefits for efficiency by minimizing the load, no-load and fan losses with the purchase price.

1. Losses

In performing system reinforcements, system losses shall be taken into consideration. Where appropriate, projects can be modified (e.g., advanced installation date, additional feeders, increase in wire size, etc.) where cost justified. Reductions in losses may also be credited towards LIPA's energy efficiency goals.

IV. Load Forecast Criteria

The planning process for the T&D System begins with the load forecast. The load forecast at the system level is based on econometric models and is developed on both a weather-normalized and weather-probabilistic basis as described below. Load forecasts are also developed for specific load areas using system load data acquired by the Energy Management System (EMS) and other systems in LIPA's T&D Operations. Specific techniques have been developed to weather normalize system load data on an area specific basis. Major known or planned load additions are also factored into the area load forecast, so that the total load growth in an area is the sum of major new load additions and the underlying load growth rate.

A. PEAK LOAD FORECAST

The peak load forecast is used for short and long-term capacity planning evaluations, the evaluation of specific projects and alternatives for the resource mix, transmission planning and distribution planning. In addition, the peak-load forecasts are necessary for LIPA to comply with regulatory requirements, including *New York State's Section 6-106 Energy Planning Process and EIA Form A-411*. Forecasts are also provided to the NYISO for Installed Capacity and planning purposes.

Econometric regression models are developed to establish the relationships between the historic values of monthly or annual electricity consumption and the variables that are considered to drive consumption, including weather, number of customers, employment, income, gross metro product and the price of electricity, among others.

Predicted values of econometric and demographic variables and normal weather variables are used in the models to produce the forecasted customer consumption of electricity. The system sales forecast is developed from four residential and twelve commercial/industrial models predicting monthly sales and annual use per customer, along with simple trending for several of the smaller rate classes and categories. The individual models used to develop the reference and alternative load forecasts are described in greater detail as follows:

1. Peak Normalization Model

Normalization of system peak demand uses normal weather defined as the average of the actual peak producing weather conditions experienced over the past thirty years. Normalization is achieved from a peak demand use per customer regression model developed to establish the historical relationship between the LIPA peak demand and the key weather variables such as temperature and humidity. The model is used to adjust the actual peak demand occurring at experienced weather conditions to normal demand at normal weather.

2. Summer Peak Demand Forecasts

The Summer Peak Load forecast is developed using the *Hourly Electric Load Model (HELM™) developed by the Electric Power Research Institute (EPRI)*. HELM™ is used to "share down" forecast annual sales into monthly, daily and hourly sales and therefore provides a realistic, bottom-up approach to peak demand forecasting by capturing the changing relationships among the residential, commercial and industrial components used to model LIPA System Sales. The energy forecast is disaggregated into the 13 residential, commercial, industrial, street lighting and rail road rate classes represented in HELM™, and the resulting HELM™ peak demand forecast is calibrated to the normalized system peak demand described above prior to predicting future peaks.

In order to better position LIPA to respond to the changing conditions that define the load forecasts a probabilistic approach is taken to develop the reference and alternative forecast scenarios.

3. Spring/Fall and Winter Peak Demand Forecasts

The methodology described above is also used to forecast the Spring/Fall and Winter Peak demand.

4. Probabilistic Summer Peak Demand Forecast

Due to uncertainty of future peak load weather, a range of forecasts are developed based on a normalized distribution of historic weather conditions. The actual peak load producing weather experienced during the past thirty years is used to develop energy and peak-load probability tables. These tables show the probability for any of the peak load producing weather conditions experienced over the past thirty years to reoccur and the peak load expected under that weather. Using this information, peaks can be predicted for a cool summer season, normal summer season, hot summer season and extreme heat summer season. The LIPA peak load forecasts are usually reported for normal (50%) weather conditions. Where additional reliability requirements are essential, forecasts for hotter than normal temperatures may be used for planning, design and rating. The use of alternative weather forecast requirements are noted in the planning standard.

B. Light Load (or Minimum Load) Forecast Criteria

The minimum system load usually occurs in the shoulder periods of April - May or November, with negligible weather sensitivity. The first estimate for the growth in the minimum load is to analyze the minimum loads for the previous seven years to determine the typical annual experienced growth. The second estimate uses HELM™ (described previously) to simulate future growth. Then the average of the two estimates for growth are added to the minimum load experienced during the previous year, to develop forecasted minimum loads. For Long Island Control Area during 2009, the actual minimum load was 1,507 MW that occurred on November 1st. For 2010, an estimated range of values from 1,518 MW to 1,565 MW was developed, best represented as 1,542 MW.

C. Area Load Pocket Forecasting

The Area Load Pocket load forecast is based on the previous summer or winter experienced peak load. The area load forecast procedure distributes the projected system peak load increase into each area, coincident with the system peak and predicting each area's own peak. Individual substation load is forecasted for the next ten (10) years based on historical trends for the individual substation/circuit service area plus known major load additions planned for future years.

V. Transmission System Planning

The ability of the bulk transmission system to withstand representative and extreme contingencies is determined by simulation testing of the system as prescribed by the NYSRC Rules. LIPA, as transmission owner, pursuant to contractual arrangements consistent with applicable NYISO guidelines, determines thermal ratings and voltage limits for facilities to be included in transmission planning assessments. These ratings and limits are used for all studies conducted by the NYISO and Transmission Owners and in the operation of the bulk transmission system.

When performing transmission system analyses various transmission alternatives may be considered for solving a particular need. Representative transmission alternatives include:

1. Expansion of sub-transmission system
2. Expansion of 345 kV and 138 kV bulk transmission system
3. HVDC
4. Superconducting cable
5. Flexible AC transmission (FACTS)
6. Dynamic ratings
7. Dynamic reactive control devices (D-VAR, SVC, etc.)

When considering alternatives 1 through 5, right-of-way optimization through use of existing corridors or railroad right-of-way is performed.

When a system study scope is developed, a list of technologies to be evaluated will be included. That list may be modified during the conduct of the study. Depending on the technology and potential impacts, the following active transmission control device issues may need to be analyzed:

a. Harmonics
b. Voltage Ride Through
c. IT (Telephone Interference)
d. SSTI (Sub Synchronous Torsional Interaction)

Reviews of electrical performance characteristic models are done by LIPA for all significant Long Island facilities including, but not limited to, power plants, merchant transmission lines, FACTs devices and non-LIPA loads. All such facilities are required to provide modeling information to LIPA and advise LIPA in advance of any planned changes to electrical plant characteristics.

A. TRANSMISSION PLANNING CRITERIA AND STANDARDS

The set of rules and standards that determine the manner in which an electrical system is planned and operated are collectively referred to as the planning criteria. These criteria ensure that alternative solutions are compared on an equal basis and that the system is planned and built to maintain a consistent level of reliability.

LIPA follows the planning criteria and standards established by NERC, NPCC and the NYSRC for its bulk transmission system. The NYISO tariff (OATT or MST) provides the NYISO with responsibility to lead the study and assessment process for transmission expansion (at or above 100 kV) and generator interconnections (larger than 20 MW) to the NYISO system. The NERC reliability standards and the NPCC reliability criteria and directories are followed by the NYISO in conducting studies and assessments associated with transmission expansion and interconnection. The LIPA sub-transmission system is designed to comply with the transmission design criteria when applicable as noted below. The criteria and standards are prescribed in the following documents:

- NERC *Planning Standards* (See Appendix 1)
- NPCC Directory 1 -- *Design and Operation of the Bulk Power System* (See Appendix 3)
- NYSRC *Reliability Rules for Planning and Operating the New York Bulk Power System*. (See Appendix 2)

The above documents describe the performance standards and analyses requirements to be used in the planning and design of the BPS as have been established by NERC, NPCC and NYSRC, respectively.

1. Contingency Criteria

The LIPA *Bulk Transmission System* is planned with sufficient transmission capability to withstand specific contingencies at projected customer demand levels and anticipated power transfer levels. These representative contingencies are listed in Exhibit 6 below. Analysis of these contingencies includes thermal, voltage, and stability assessments as defined by system design “Rules”. These Rules apply after the contingency outage of any critical generator, AC or HVDC transmission circuit, transformer, or series or shunt compensating device, and after generation and power flows are adjusted between outages by the use of *ten minute reserve* and, where available, phase angle regulator control and HVDC control.

The contingency design criteria described in Exhibit 6 is also used in the design of the sub transmission system. LIPA has implemented an exclusion of item b) as a single contingency when an outage is primarily driven by weather[7] provided that the circuit is on a steel structure, has been designated as part of a special high maintenance program, and the following effects are not associated with the outage:

- Voltage collapse
- Angular instability
- Cascading effect on areas outside of immediate local area

Operations will, when possible, treat weather impacted double circuit lines as a single contingency when the weather conditions are present. This exclusion will continue to be evaluated considering actual operating experience.

[7] Double circuit structures on highways or streets not protected by guard rails will not be excluded since traffic related outages are weather independent.

Exhibit 6 Design Criteria Contingencies

a)	A permanent three-phase fault on any generator, transmission circuit, transformer or bus section, with normal fault clearing.
b)	Simultaneous permanent phase-to-ground faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with normal fault clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is not applicable.
c)	A permanent phase-to-ground fault on any generator, transmission circuit, transformer or bus section, with delayed fault clearing.
d)	Loss of any element without a fault.
e)	A permanent phase-to-ground fault on a circuit breaker, with normal fault clearing. (Normal fault clearing time for this condition may not always be high speed.)
f)	Simultaneous permanent loss of both poles of a direct current bipolar High Voltage Direct Current (HVDC) facility without an AC fault.
g)	The failure of a circuit breaker associated with a Special Protection System (SPS) to operate when required following: loss of any element without a fault; or a permanent phase-to-ground fault, with normal fault clearing, on any transmission circuit, transformer or bus section.

Source: NYSRC Reliability Rules for Planning and Operating the New York State Power System - Table A

In general, the design of LIPA's transmission systems adheres to the following principles:

- The bulk transmission system shall be planned with sufficient emergency transfer capacity to accommodate the established generation reliability criteria of one disconnect incident in ten years using peak load forecast uncertainty.
- The transmission system shall be planned with normal transfer capacity sufficient to keep significant load and generation pockets to a minimum as specified in sections B through H below.

- The bulk transmission system shall be designed to comply with all applicable NERC, NPCC, NYSRC and all other applicable LIPA planning and design standards (See Appendices 1, 2, 3 and 7).
- The sub-transmission system is designed to comply with the LIPA planning design standards contained herein.
- During normal[8] and extreme[9] weather conditions, the transmission system will meet New York Control Area (NYCA) voltage design standards after the loss of the two largest reactive sources.
- Fault duty studies will be conducted periodically under planned system reinforcement scenarios to determine if there are any three phase, line-to-line-to-ground, or line-to-ground fault circuit breaker overstress conditions. These studies will be conducted following the *NYISO Guidelines for Fault Current Assessment* (See Appendix 5).

Major transmission projects, voltages at 100 kV or higher, involving interconnections and the reinforcement of the transmission system are based on New York State Reliability Council planning, design, and operating standards. This maintains a consistency of standards among all market participants in New York State, thereby permitting uniform operating procedures in the interchange of power.

2. Dynamic Ratings

All thermal overloads on overhead sub transmission lines are identified via analyses performed using planning analytical tools, and all overloads of 10% and above are addressed through capital improvement projects. For overhead sub transmission line overloads less than 10%, LIPA is exploring the possibility of re-rating these circuits on a circuit-by-circuit basis. Subsequently, LIPA has installed monitoring equipment on

[8] 50% probability predicted peak will exceed experienced peak
[9] 5% probability predicted peak will exceed experienced peak

several overhead sub transmission lines experiencing contingency overloads with the expectation that some overhead lines will be re-rated and that the system will identify line ratings based upon actual weather and field conditions.

3. *Line Re-Ratings*

As a result of a detailed study, LIPA identified line re-rating opportunities based on wind speeds/directions and sheltering[10] impacts to be deployed when a facility is approaching its rated limits. Based on the analysis, each LIPA transmission line would be placed into one of three categories: heavily sheltered, moderately sheltered, and lightly sheltered (see table below).

Table 3 Sheltering Classification

	Lightly Sheltered	Moderately Sheltered	Heavily Sheltered
Tree or Building height less than 60 ft horizontally away from line	< 2/3 H	< 1.0 H	> 1.0 H
Tree or Building height 60-200 ft horizontally away from line	< 1.0 H	< 1.5 H	> 1.5 H
	Both criteria must be met to qualify	Both criteria must be met to qualify	Either criteria must be met to qualify
H = line height = lowest point on the line between poles			

Any transmission line classified as heavily or moderately sheltered is assumed to retain its static rating. A transmission line classified as lightly sheltered would typically experience an off-peak rating increase of 8% and an on-peak rating increase of 10% based upon a 95% confidence level.

[10] Wind sheltering is caused by tall objects blocking the wind and reducing airflow across nearby transmission lines

Alternatives for moving a transmission line to the lightly sheltered category may include: reframe/ reconfigure transmission structures to increase height, trim / top trees which are obstructing wind flow across lines, and remove / relocate any under built facilities to effectively increase height of lowest point between structures.

4. HVDC Supply Backup Design

For power sources supplying HVDC stations LIPA adheres to the Northeast Power Coordinating Council (NPCC) requirement for station service AC supply[11]. This requirement states:

> "On bulk power system facilities, there shall be two sources of station AC supply, each capable of carrying at least all the critical loads associated with protection systems".

The two power sources shall not be subjected to a single contingency or to a common mode failure.

B. THERMAL ASSESSMENT CRITERIA[12]

1. Pre-Contingency Thermal Criteria

1. For *normal transfers*, no transmission facility shall be loaded beyond its *normal rating*, or exceed its applicable emergency rating on the event of a contingency.
2. For *emergency transfers*, no transmission facility shall be loaded beyond its *normal rating*. However, a facility may be loaded to the Long-Term Emergency (LTE) rating

[11] NPCC Document A-5 - Bulk Power System Protection Criteria, Section 3.6
[12] NYSRC Reliability Rules B-R1

pre-contingency, if the Short-Term Emergency (STE) rating is reduced accordingly[13] and post-contingent flows do not exceed the revised STE rating.

2. Post-Contingency Thermal Criteria

a. For *normal transfers*, no facility shall be loaded beyond its *LTE rating* following the most severe of design criteria contingencies "a" through "g" specified in Exhibit 6 above.

An ***underground cable*** circuit may be loaded to its *STE rating* following:

- *Loss of Generation* - provided ten (10) minute operating reserve and/or phase angle regulation is available to reduce the loading to its *LTE rating* within 15 minutes and not cause any other facility to be loaded beyond its *LTE rating*.

- *Loss of Transmission Facilities* - provided a controllable flow device such as a phase angle regulator is available to reduce the loading to its *LTE rating* within 15 minutes and not cause any other facility to be loaded beyond its *LTE rating*.

For design criteria contingencies "b", "c", "e", "f", and "g" in Exhibit 6 that are not confined to the loss of a single element, *transmission owners* may request permission from the NYISO to design the system so that post-contingency flows up to the *STE ratings* on the remaining facilities can occur. This is permissible provided operating measures are available to reduce the loading to its *LTE rating* within 15 minutes and not cause any other facility to be loaded beyond its *LTE rating*. Design exceptions should be well documented,

[13] See Equipment Rating Criteria Sections VIII-A and VIII-B

including NYISO comments, and must be approved by the NYSRC. To date, LIPA has not filed for any exceptions to the NYSRC criteria.

b. For *emergency transfers*, no facility shall be loaded beyond its STE rating following the more severe of design criteria contingencies “a” or “d” listed in Exhibit 6. The *STE rating* is based on an assumed pre-loading equal to the *normal rating*. Therefore, if the limiting facility is loaded above its *normal rating* pre-contingency, the *STE rating* must be reduced accordingly.

C. VOLTAGE ASSESSMENT CRITERIA[14]

Reactive power shall be maintained within the LIPA *bulk transmission system (BTS)* in order to maintain voltages within applicable pre-disturbance and post-disturbance limits for both normal and emergency transfers, consistent with the NYSRC Reliability Rules and all applicable guidelines and procedures. The LIPA power system is designed to accommodate the voltage criteria under extreme weather conditions[15].

1. Pre-Contingency Voltage Criteria

For both *normal and emergency transfers*, no bus voltage shall be below its pre-contingency low voltage limit nor be above its pre-contingency high voltage limit. *Pre-contingency* v*oltages shall be maintained at no less than 95% or more than 105% of the base system voltage.*

2. Post-Contingency Voltage Criteria

[14] NYSRC Reliability Rules B-R2
[15] 5 % probability that predicted peak will exceed experienced peak.

No bus voltage shall fall below its post-contingency low voltage limit nor rise above its post-contingency high voltage limit. For *normal transfers*, design criteria contingencies "a" through "g" specified in Exhibit 6 are applicable. For *emergency transfers*, design criteria contingencies "a" and "d" specified in Exhibit 6 are applicable. *Post-contingency voltages shall be maintained at no less than 95% or more than 105% of the base system voltage*[16]*.*

Voltage analysis will be performed for both peak and light load conditions as part of system reliability impact studies.

When a switching element is energized or de-energized, the fundamental system voltage increases or decreases, "Delta-V," depending upon the switching element and system conditions. Bus voltage affected by the switched element shall not change by more than +/- 2.5% as a result of the switching. Analyses of the Delta-V impacts shall be assessed for different LIPA system conditions, including load level and generation dispatch.

3. Transient Voltage Recovery

Transient voltage recovery analysis will be performed for both peak and light load conditions as part of the "Other Studies" under the NYISO Large Facilities Interconnection Process according to current LIPA methodology. Siemens Power Technologies' PSS™/E program is used for this evaluation. Complex load models are utilized as appropriate for specific system conditions. LIPA has adopted the following transient voltage recovery criteria:

- Voltages on all LIPA 138 kV and 69 kV buses shall recover to at least 0.90 P.U. of the nominal voltage within one second of the clearing of the simulated

[16] Post-Contingency, sub-transmission system voltages below 69 kV shall be maintained at no

fault, and remain continuously above 0.90 P.U. of the nominal voltage, excluding the reoccurrence of a fault within this one second period.

These criteria have been developed based on the existing transient voltage criteria from the following entities:

- WECC (Western Electric Coordinating Council)
- MAPP (Mid-Atlantic Area Power Pool)
- AESO (Alberta Electric System Operator), Canada
- IESO (Independent Electricity System Operator), Canada
- ISO – NE

Currently, there are two areas that require dispatch of generating units in order to comply with this requirement. The areas are the East End and East of Holbrook. Information on generation dispatch is posted by LIPA on its OASIS.

4. NYISO VAR Study

LIPA is participating in the NYISO Reactive Power Working Group (RPWG) which is addressing the issues and concerns associated with the accurate determination of transmission voltage constraints of NYCA interfaces. This effort addresses the following objectives:

- Review of the reactive load representation in operating and planning studies and the comparison of forecasted reactive load to experienced real time system loads.

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less than 90% or more than 110% of base system voltage.

- Review of *NYISO Transmission Planning Guideline #2*, and the assessment of the need to recommend additional reliability measures to maintain the reliability of the New York transmission system.
- Following closely the activities of NERC and NPCC related to reactive power criteria and compliance.

The RPWG will present recommendations to the NYISO Operating Committee, and if approved, LIPA will incorporate the recommendations into the LIPA criteria.

D. NEW AND ALTERNATIVE TECHNOLOGY CRITERIA

1. High Voltage Direct Current (HVDC)

HVDC transmission (conventional HVDC or “DC-Lite”/ Voltage Source Converter technology) can be used to supply system capacity requirements. Each HVDC project is unique, and the technical challenges can be quite different for each application. In order to attain the full benefit of HVDC for a given application, to identify DC/AC system performance requirements and component ratings, to ensure conformance with performance requirements and to ensure a reliable interconnection to the AC system, it is necessary to perform comprehensive engineering studies during the planning, specification and design stages of the project.

Prior to design of the HVDC project, a Technical Design Specification, Performance Requirements and Operating Standards document must be drafted, and reviewed and approved by all parties. This document will specify performance requirements which must be satisfied by the HVDC system, along with requirements of the AC system to ensure reliable operation. It will also specify major studies which the HVDC project developer will be responsible for completing.

The following performance requirements and technical studies must be addressed. Such study efforts would be required in addition to the formal requirements of the NYISO Interconnection process (Attachment X and S requirements). Depending upon specific project requirements, additional studies may be needed.

a. *Main Circuit Design Study*

This study contains the design calculations in order to define the main HVDC circuit equipment parameters and the steady state operating characteristics of the HVDC project. Ratings of all equipment shall be specified.

b. *AC System Reactive Power Requirements Study*

The purpose of this study is to determine the amount of reactive power support required to maintain AC system bus voltages within criteria, over the full range of HVDC import/export capability.

c. *Reactive Power Study*

The purpose of this study is to dimension the reactive power supply and absorption equipment at the converter station, and to establish a reactive power compensation concept to satisfy the AC system requirements.

d. *AC System Equivalent Study*

The purpose of this study is to define an equivalent representation of the remaining AC system (not including the explicit representation of the HVDC project and adjacent substations) for use in dynamic performance studies

e. *Dynamic Performance Study*

The purpose of this study is to verify that the response to disturbances does not cause instability in the integrated HVDC/AC system, and to verify the proper dynamic and steady state performance of the overall HVDC system with all controls and important equipment modeled together.

f. *Real Time Digital Simulation Study*

The purpose of the study is to verify the dynamic behavior of the LIPA system in real time using a digital simulator and actual converter station control hardware. The study shall apply various dynamic events to the LIPA system and analyze the behavior of the HVDC controls.

g. *Functional Performance Study*

The purpose of this study is to functionally test Control and Protection (C&P) equipment and to verify proper operation of the individual C&P cubicles and correct interaction and functionality of the interfaces between the cubicles.

h. *Load Flow and Stability Model Study*

The purpose of this study is to design and provide modeling information that can be used to represent the HVDC system and all associated equipment in load flow, short circuit and stability databases / studies.

i. AC System Impedance for Harmonics Study

The purpose of this study is to develop impedance sectors for the HVDC terminal, and to define the AC system impedance seen at the interconnecting substation for various harmonic frequencies. This data will be utilized to design converter station AC harmonic filters.

j. AC Filter Performance and Rating Study

The purpose of this study is to design an AC filtering scheme which will satisfy harmonic performance requirements, and at the same time satisfy reactive compensation requirements. Demonstration of filter performance (harmonic voltage distortion, IT product, etc...) and verification of filter ratings are required.

k. Telephone Interference Study

Based on AC harmonic performance results, a detailed telephone circuit interference study may be required to assess the potential for phone circuit noise.

l. Sub synchronous Torsional Interaction (SSTI) Study

Torsional interaction between an HVDC system and a turbine generator is a phenomenon whereby the DC control system influences the damping of rotor torsional modes of oscillation of nearby turbine generators. The purpose of this study is to assess the level of potential SSTI and to design mitigation schemes, if needed.

m. AC Protection System Study

The purpose of this study is to develop an overall protection strategy for the HVDC system and interconnecting AC system facilities.

n. *Interconnection Facility Circuit Breaker Requirements Study*

The purpose of this study is to define specific technical requirements for AC circuit breakers installed at the HVDC converter station, and to determine the specific switching requirements of the Interconnection Facility circuit breakers.

o. *Insulation Coordination Study*

The purpose of this study is to develop and specify insulation and over voltage protection requirements for the HVDC system and interconnecting AC system facilities, and to demonstrate adequate levels of insulation coordination.

p. *Temporary Over voltage (TOV) Study*

The purpose of this study is to evaluate potential for over voltages and to develop and describe over voltage control strategies for different fault scenarios and system conditions for rectifier and inverter operation with or without recovery of the HVDC.

q. *Power Line Carrier (PLC) Performance Verification Study*

Conducted electromagnetic noise on the power lines interconnected to the HVDC converter station could potentially interfere with PLC communication systems. The purpose of this study is to describe the levels of electromagnetic interference associated with the operation of the HVDC converter station. The study shall detail the basic source of interference noise, the propagation mechanism of the interference noise, the levels of interference noise at points of interest as well as suitable measures which may be required in order to reduce the interference noise to tolerable levels (i.e. design of filters).

r. Electrical Interference Study

The purpose of this study is to give a quantitative description of the levels of high frequency electromagnetic interference associated with the operation of the HVDC converter station, and to verify conformance with related technical performance requirements.

s. Remote Operator Control Study

The purpose of this study is to develop a functional layout for the remote operator control system. Control block diagrams, SCADA data summaries, remote AC voltage control schemes, remote reactive power control schemes, remote DC power control schemes, etc… will be developed.

t. Efficiency / Loss Evaluation Study

The purpose of this study is to calculate HVDC system losses.

u. Converter Station Service Supply System Study

The purpose of this study is to define HVDC converter station AC power supply requirements, summarize the design and interconnection of independent station service AC supplies from the LIPA system and verify that the supplies shall not be subjected to a single contingency or to a common mode failure.

v. Bulk Power System (BPS) Criteria Study

The purpose of this study is to determine whether the HVDC system and associated interconnecting facilities should be classified as part of the NPCC Bulk Power

System (BPS) and to document compliance of newly identified BPS facilities with NPCC BPS design criteria.

w. *Control System Interaction Study*

The purpose of this study is to determine if any adverse control system interactions will exist with nearby HVDC or power electronic system facilities, and to identify remedial design measures.

x. *LIPA System Generation Displacement Study*

The purpose of this study is to identify any adverse system impacts due to possible displacement of local generation, and its reserve requirement, by a HVDC project. Transient voltage recovery, dynamic reactive power, minimum short circuit levels for reliable HVDC operation and the impact on LIPA system protective relay systems shall be assessed.

y. *System Restoration Study*

The purpose of this study is to determine the impact of the HVDC project and associated blackstart capabilities (if any) on System Operation restoration procedures.

2. Superconductor Cable

a. Recent advances in new ceramic superconducting compounds have enabled the development of high temperature superconductivity. LIPA is in the process of installing a 2,000 feet superconducting cable that will be connected in series with an existing 138 kV overhead transmission line. The cable will use liquid nitrogen as the coolant and nitrogen cooling equipment will be installed at one end of the cable. Future use of this technology is being considered because it offers the following potential benefits:

- *Increase power transmission capabilities in existing rights-of-way*
  - Superconducting cables (SCC) can move 2 – 5 times more power than a conventional cable of the same size.

- *Reduce or eliminate environmental impacts in new and existing rights-of-way*
  - SCC contains no oil, eliminating containment issues associated with conventional oil-filled cables. The shielded construction of superconducting cables also eliminates external electromagnetic fields common to overhead and underground transmission technologies.
- *Minimize permitting by reusing rights-of-way*
  - SCC eliminates the need to increase system voltages to increase system capacity, allowing capacity increases in existing permitted rights-of-way.

- *Greater control of AC power flow within the grid*
  - The reduced resistance of superconducting cables means that they can be strategically placed in the electric grid to draw flow away from overtaxed conventional cables or overhead lines, thereby relieving network congestion

b. Special Design Considerations

- *Remote Fault Clearing*

  Special consideration has to be given to impacts of remote faults on the superconductor cable installations. Remote fault evaluation has to be conducted in the context of specific installation in order to assess conditions when the superconductor cable is to be removed from service as a result of the cooling system inability to withstand multiple exposures to high fault currents within a pre-defined time period.

3. Smart Grid

The Authority is pursuing a high-tech approach for managing the electric system by developing projects to enhance its smart grid technology: (1) a $49.6 million Dynamic Reactive Support System Project (DRSS-II) and, (2) a $69.5 million Smart Grid Communications Backbone. The DRSS-II is a state-of-the-art voltage management system on the transmission system that will reduce the possibility of blackouts and cut costs and emissions by eliminating some of the mandatory use of oil and gas fired generators. The Smart Grid Communication Backbone is a fiber optic and radio communications network that will connect all LIPA substations enabling LIPA to take the next step in implementing a smart grid on Long Island.

LIPA is also participating in a NYISO statewide transmission system Phasor Measurement Network (PMN) that was selected by the Department of Energy (DOE) as part of the smart Grid Investment Grant Program. The PMN includes installation of Phasor Measurement Units (PMU) across the state as well as development of tools to analyze and present the data. This project promises to enhance transmission system reliability throughout the region. These applications are consistent with the Governor's 45x15 initiatives and reinforce our commitment to move ahead with these important smart grid projects which will modernize our electric system, reduce energy costs and stimulate the local economy with the creation of new clean energy jobs.

LIPA also filed an application with the DOE for Smart Grid Stimulus Demonstration Funding and has been awarded 50% of the cost ($25 million) for the development of a Smart Grid Corridor Project. This project, located along Route 110 business corridor and involving 800 customers, is a partnership comprised of LIPA, Stony Brook University and Farmingdale State College. It will assist residential, commercial and industrial LIPA customers in monitoring and reducing energy usage, increase reliability, encourage energy efficiency by facilitating smarter technologies, and create clean energy jobs through the new smart grid businesses and new educational curriculums. It would also create New York State's first Smart Campus that would directly tie smart grid systems with energy conservation and renewable technologies.

These projects will continue LIPA's leadership role as it was the first utility in New York to deploy smart meters in March of 2009 when the Authority announced a pilot program in Hauppauge and Bethpage to provide information on how smart meters will help customers receive real-time information about their energy usage, help them to use energy more efficiently and save on their electricity bills.

E. DYNAMIC STABILITY ASSESSMENT CRITERIA[17]

1. System Stability

1.1 For *normal transfers*, stability of the LIPA *bulk transmission system* (BTS) and the sub transmission system shall be maintained during and after the most severe of design criteria contingencies "a" through "g" specified in Exhibit 6. The *BTS* must also be stable if the faulted element is re-energized by delayed reclosing before any manual system adjustment, unless specified alternate procedures are documented.

1.2 For *emergency transfers*, stability of the LIPA *BTS* and sub transmission system shall be maintained during and after the more severe of design

[17] NYSRC Reliability Rules B-R3

criteria contingencies “a” or “d” specified in Exhibit 6. The *BTS* must also be stable if the faulted element is re-energized by delayed reclosing before any manual system adjustment. Emergency transfer levels may require generation adjustment before manually reclosing faulted elements not equipped with automatic reclosing or whose automatic reclosing capability has been rendered inoperative.

2. Generator Unit Stability - Transmission Considerations

With all transmission facilities in service, generator unit stability shall be maintained on those facilities not directly involved in clearing the fault for:

2.1 A permanent phase-to-ground fault on any generator, transmission circuit, transformer or bus section, with normal fault clearing and with due regard to reclosing.

2.2 A permanent three-phase fault on any generator, transmission circuit, transformer or bus section, with Normal Fault clearing and with due regard to reclosing.

The LIPA system stability is reviewed periodically when significant system changes occur such as the addition of new generation facilities and/or modifications to the transmission system. This analysis will be performed for both peak and light load conditions as part of system reliability impact studies for targeted areas of LIPA system.

F. ASSESSMENT CRITERIA- EXTREME CONTINGENCY CONDITIONS

Assessment of extreme contingencies is also needed to recognize that the bulk power system may be subjected to events that exceed in severity the representative contingencies in Exhibit 6. These assessments measure the robustness of the transmission system and should be evaluated for risks and consequences. One of the objectives of extreme contingency assessment is to determine, through planning studies, the effects of extreme contingencies on system performance. Extreme contingency assessments provide an indication of system strength, or determine the extent of a widespread system disturbance even though extreme contingencies do have low probabilities of occurrence. Extreme contingency assessments examine several specific contingencies listed in the Rules[18]. They are intended to serve as a means of identifying those particular situations that may result in a widespread bulk power system shutdown.

Analytical studies shall be performed to determine the effect of the extreme contingencies outlined in Exhibit 7 below. Assessment of the extreme contingencies shall examine post-contingency steady state conditions as well as stability, overload cascading and voltage collapse. Pre-contingency load flows chosen for analysis should reflect reasonable power transfer conditions. The testing shall be conducted at megawatt transfers at the expected average transfer level. This may be at or near the normal transfer limit for some interfaces.

After due assessment of extreme contingencies, measures will be used where appropriate, to reduce the frequency of occurrence of such contingencies or to mitigate the consequences expected as a result of testing for such contingencies.

1. Extreme Case Contingencies - Definition

As noted in Exhibit 7 below, LIPA defines as Extreme Contingencies as the loss of all transmission circuits emanating from a generation station, switching station, HVDC

[18] NYSRC Reliability Rules B-R4

terminal or substation. This is based on one of the Extreme Contingencies defined by the NYSRC. LIPA will consider the impact of extreme contingencies as described above as a measure of system strength only.

Exhibit 7 Extreme Contingencies

a. Loss of the entire capability of a generating station.
b. Loss of all lines emanating from a generating station, switching station or substation.
c. Loss of all transmission circuits on a common right-of-way.
d. Permanent three-phase fault on any generator, transmission circuit, transformer, or bus section, with delayed fault clearing and with due regard to reclosing.
e. The sudden loss of a large load or major load center.
f. The effect of severe power swings arising from disturbances outside the BPS.
g. Failure of a Special Protection Scheme (SPS) to operate when required following the normal contingencies listed in Exhibit 6.
h. The operation or partial operation of a SPS for an event or condition for which it was not intended to operate.
i. Loss of multiple external tie-lines.

Source: NYSRC Reliability Rules for Planning and Operating the New York State Power System -Table B

G. SHORT CIRCUIT ASSESSMENT CRITERIA

Breaker fault duty studies will be conducted periodically under various planned system reinforcement scenarios to determine if there are any *three phase,* phase-to-phase-to-ground *or phase-to-ground* fault circuit breaker overstress conditions. Studies will follow the *NYISO Guidelines for Fault Current Assessment*. (See Appendix 5)

1. Circuit Breaker Replacement Criteria

Evaluations of transmission circuit breaker fault duties are conducted using the ASPEN™ Breaker Rating Module. Similar to NYISO study process, screening is performed by comparing substation bus maximum short circuit values to the lowest rated breaker associated with that substation bus. Then individual breaker analysis is performed for substations where maximum total short circuit at the bus exceeds the capability of the lowest rated breaker in that substation. The process involves entering into the ASPEN™ short circuit data file the fault interrupting characteristics of each transmission circuit breaker (23 kV through 345 kV). This data is obtained from the Substation Maintenance records or from the breaker manufacturers' data. The ASPEN™ Breaker Rating Module then accesses the short circuit data file, calculates the fault duty stress on each transmission circuit breaker and identifies those that it determines will be overstressed. This analysis will be performed for peak load conditions as part of system reliability impact studies for targeted areas of LIPA system.

To ensure service reliability, all circuit breakers stressed above rating and those expected to operate above the capacitive interrupting rating shall be recommended for potential replacement.

H. Reactive Power Reserve Criteria

Sufficient reactive resources must be located throughout the electric systems, with an appropriate balance between static and dynamic characteristics. Both static and dynamic reactive power resources are needed to supply the reactive power requirements of customer demands and the reactive power losses in the transmission and distribution systems, and provide adequate system voltage support and control. They are also necessary to avoid voltage instability and widespread system collapse in the event of certain contingencies. Synchronous generators and static VAR compensators (SVCs) provide dynamic support while transmission line charging and shunt capacitors supply static sources of reactive support.

Shunt capacitors are installed at substations and on primary distribution circuits in accordance with recommendations of the annual LIPA Reactive Resource Study report. The size, type and locations of the reactive resources are evaluated as part of this study under various assumptions such as new generation, dynamic VAR resource and transmission line reinforcements (overhead versus underground lines). LIPA makes every effort to install capacitors close to the load. However, saturation of the distribution system with capacitors requires some use of substation capacitors.

The LIPA transmission system reactive reserve design criteria will meet NERC and NYISO design standards for normal system conditions, loss of a single component and for the loss of two (largest generators) components. The system is designed to accommodate extreme weather load forecast projections.

- *Reactive Power Criteria*

  S1. Reactive power resources, with a balance between static and dynamic characteristics, shall be planned and distributed throughout the interconnected transmission systems to ensure system performance as defined in Categories A, B, and C of Table I - Transmission System Standards for Normal and Contingency Conditions in Section I-A of NERC Planning Standards.[19]

The 2003 Reactive Resource Study report (June 2003) indicates that at a minimum, 120 MVAR reactive support will be required annually for the next 10 years to meet system reactive reserve criteria. A portion of this would be dynamic reserve for maintaining system voltage performances at times of severe summer weather peaks.

[19] See Appendix 1 - NERC Planning Standards Sect. I-D. Voltage Support and Reactive Power.

I. POWER FACTOR CRITERIA

Generators/Interconnections - Should a generator desire to interconnect to LIPA's transmission or distribution system, the facility (e.g., synchronous generator, induction generators, D.C. generators with inverters, HVDC, PV, Wind or other similar technology) shall be designed to provide reactive power support to the LIPA system.

A) For synchronous generators greater than 300 kVA and non-synchronous generators (e.g., induction and inverter based) greater than 2 MVA, the units shall be designed to operate over a range of plus or minus (+/- lagging/leading) 0.90 power factor at its rated capacity value at the point of delivery. LIPA's system operators may direct the generator to adjust the power factor of the facility at the delivery point within the above stated limits on a scheduled or real-time basis at LIPA's discretion.[20] For example, for a 100 MW facility the reactive support shall be able to provide between plus or minus 48 MVAR. This reactive output capability shall be maintained over all operating levels.

B) For synchronous generators equal to or less than 300 kVA and non-synchronous generators (e.g., induction and inverter based) equal to or less than 2 MVA shall provide controllable reactive compensation equivalent to 0.90 and 1.00 p.u. lagging at the point of interconnection or alternatively the developer at its expense may request LIPA to provide reactive capacity from its system.

The method of complying with the reactive support requirements shall be reviewed and approved by LIPA prior to installation.

Any electrical interconnection, AC or DC, shall be designed with sufficient fixed, mechanically switched and/or dynamically controlled reactive power support so as to provide for satisfactory performance and contribute to maintaining voltage on the LIPA system within acceptable limits. The reactive supply must include the sum of:

1) Sufficient reactive power supply and absorption to satisfy the internal needs for reactive power (supply and absorption) of the interconnection while operating at voltages between 0.95 p.u. and 1.05 p.u., concurrently with meeting all performance requirements that may be identified as part of the studies required to be performed. (e.g., see New Technologies section)

2) Additional reactive power supply and absorption capability to compensate for any voltage changes on the LIPA system caused by the import or export of power through the interconnection.

Any necessary engineering studies for the above facilities shall be performed at generator's or interconnector's expense. This reactive output must be demonstrated on an annual basis unless LIPA has established different requirements.

- LIPA, Con Edison and Northeast Utilities agree to maintain adequate voltage on *interconnections* with each other by operating their respective systems so that the reactive power flow on each interconnection shall not exceed one-half of the line charging (net of any shunt reactors in service) of these interconnections unless otherwise mutually agreed by their System Operators for a specified interim condition.

- All LIPA Customers shall use electricity at a Power Factor of 90 percent or greater. However, if the equipment of a Non-Residential Customer, served at or above the primary voltage level, operates so that the kilovolt-amperes of lagging Reactive Power is more than 48 percent of Real Power for any 15-minute interval, in the

[20] LIPA Interconnection Guide for Independent Power Producers. See Appendix 6

hours between 7:00 a.m. and 11:00 p.m. during a 30-day period, the Customer shall agree to either purchase, install, and maintain power-factor-corrective equipment, approved by the Authority, on the low-voltage side of the Customer's facility, or pay a monthly Reactive Power charge[21].

J. GENERATION DELIVERABILITY CRITERIA

The concept of deliverability of generation capacity is essential to good utility transmission planning and is supported by the *New York State Reliability Council Reliability Rule* A-R2[22], which states:

> *"LSEs shall be required to procure sufficient resource capacity for the entire NYISO defined obligation procurement period so as to meet the statewide IRM requirement determined from [Rule] A-R1. Further, this LSE capacity obligation shall be distributed so as to meet locational ICAP requirements, considering the availability and capability of the NYS Transmission System to maintain A-R1 reliability requirements."*

Deliverability of generation is necessary when determining locational capacity requirements. Only generation that can be delivered counts toward the locational capacity requirements and *generation that can not be delivered must be energy only*. Also, under NYISO rules it is necessary to have deliverability to bid operating reserves and ancillary services into the market.

[21] LIPA Tariff for Electric Service (5/29/98) Leaf 62 Section II-D.12 (Customer Electric Usage Obligations)
[22] See NYSRC Reliability Rules for Planning and Operating the N.Y. State Power System in Appendix 2

Fundamental to the enforcement of the NYISO locational capacity rules, the transmission system on Long Island must allow delivery of all contract capacity under peak load conditions. Based on this requirement, LIPA has established the following generator deliverability requirement for all resources providing capacity to LIPA:

> *The LIPA transmission system shall be designed to allow delivery of the aggregate of LIPA's capacity resources to the aggregate of the LIPA load under peak load conditions. Delivery of resources is based on the unforced capacity or "UCAP" of each resource.*
>
> *UCAP is defined as the Dependable Maximum Net Capability (DMNC) of each generator in its system reduced by the generator's equivalent forced outage rate (EFOR) assuming normal weather.*

The implementation of LIPA's generator deliverability requirement is based, in part, on the PJM deliverability criteria and in part on NYISO and NYSRC resource adequacy criteria. The requirement is based on the ability to deliver the capacity across LIPA's internal interfaces. (See discussion on interfaces included in Section III. "Description of the LIPA Transmission and Distribution System") these interfaces include the New bridge, Northport, and Holbrook Interfaces which divides LI into eastern, western and central regions.

- Deterministic Deliverability Criteria

To test the deliverability of a new resource, a deterministic loadflow test is employed whereby the new resource will be dispatched at its maximum power output and all existing resources (e.g., generation and interconnections) in the region would be dispatched or under peak load conditions at their UCAP value to insure that there are no restrictions on their output. If there is a limit, system improvements or a reduction in capacity rating would be considered.

For example, to test a new resource located in eastern LI, all units east of Holbrook interface including tie capacity such as CSC, must be dispatched at their respective UCAP rating with any excess power above the peak load in the area transferable westward across the Holbrook interface (generation would be reduced in western Long Island). A similar test would be done for a unit located in the western region or power from Northport station. For a unit located in the central portion, the unit addition should not restrict the existing unit deliverability across all three internal interfaces.
(For example, if a unit was located on the west side of the Holbrook interface, the new unit should not reduce the westward transfer capability across the Holbrook interface, east across the Newbridge interface or limit Northport.) In testing the deliverability of a resource, PARs maybe modified within LIPA to maximize the flows across the LIPA internal interfaces.

- Probabilistic Deliverability Test to Ensure Design does not impact NYSRC or NYISO Resource Adequacy Calculations

When reviewing deliverability LIPA shall also employ a probabilistic approach utilizing the GE MARS LOLE (Loss of Load Expectation) software to ensure the design of the system does not impact NY resource adequacy requirements. This approach involves plotting the LOLE for various transfer capacities to ensure resulting design remains on the asymptotic region of the characteristic (see illustrative plot below) and will not impact NYSRC or NYISO resource adequacy calculations such as Installed Reserve Margin, Locational Capacity Requirement, or Resource Needs Assessment.

K. Load Pockets

A load area is defined as a geographic area supplied by a networked transmission delivery system, without any transmission system limitation. If a transmission limitation exists during any part of an annual load cycle period, the load area is designated as a *load pocket.*

The LIPA service territory is subdivided into the 18 load areas summarized below and shown in Exhibit 8.

1 - Entire Island (LP[23])	7 - South Farmingdale (LP)	13 - East Brookhaven (LP)
2 - Far Rockaway (LP)	8 - Babylon (LP)	14 - West Brookhaven (LP)
3 - Barrett (LP)	9 - East of Northport (LP)	15 – East End (LP)
4 - West Glenwood (LP)	10 - South West Suffolk	16 - North Fork (LP)
5 - North East Nassau (LP)	11 - Brentwood (LP)	17 - South Fork (LP)
6 - Huntington (LP)	12 - Smithtown (LP)	18 - East of Buell (LP)

L. Load Pocket Criteria

LIPA's design objective is to eliminate the transmission limitations leading to the formation of a load pocket. LIPA will evaluate various design alternatives comparing their cost to the annual cost of "must run" generation in the load pocket.

1. Load Pocket Mitigation

The transmission limitations leading to the formation of a load pocket can be mitigated by:

- reducing the load contained in the load pocket
- building new or upgrading existing transmission facilities

[23] LP means Load Pocket (designations change based on transmission system upgrades)

- adding new efficient generation in the load pocket
- dispatch of existing generators located in the load pocket

2. Load Pockets with no Existing Generation in the Pocket

Each load area on Long Island is tested annually to determine if the circuits supplying the area meet the LIPA normal and first contingency design criteria. If there is a transmission limitation at peak load levels the area is defined as a load pocket. As part of the analysis, the load in the pocket is gradually reduced to determine the load level at which the transmission constraints are eliminated. (At that point the pocket will become a load area). Using that load level, the expected annual number of hours of exposure is determined and capital projects are recommended to either add generation or to reinforce the transmission lines supplying the pocket. These analyses are also conducted using long range load projections under normal weather conditions.

3. Load Pockets with Existing Generation in the Pocket

A similar procedure is followed for load areas with existing generation. The analysis is first conducted with no generation in service to determine if the circuits supplying the area meet the LIPA normal and first contingency design criteria. If there is a transmission limitation at peak load levels the area is defined as a load pocket. Then the load is gradually reduced to determine the load level at which transmission constraints are eliminated and if the reduced load can be met by existing generation in the pocket, that load represents potential must run generation. If there is not sufficient generation in the pocket, a recommendation is made to either add more generation or to reinforce the transmission lines supplying the pocket. These analyses are also conducted using long range load projections under normal weather conditions.

4. Out of Merit Generation vs. Transmission Reinforcements

When transmission limitations exist but generation is available in a particular area of the system that can eliminate the transmission limitations, a comparison will be made of the transmission system reinforcement costs required to meet design criteria to the cost of running more expensive generation in the area to decide if the transmission reinforcements are cost justified.

Planning will also analyze hours of exposure for a particular contingency and determine risks and consequences related to technical, financial, customer satisfaction, and regulatory requirements performance.

M. Distributed Generation Criteria for T&D and Generation Project Deferral

Distributed generation is the addition of generation to a load pocket. Small generators and micro turbines, fuel cells, photovoltaic arrays, wind and other renewable energy sources are normally used to supply the load. Usually these devices are connected to the distribution system. When considering a distributed generation alternative LIPA requires that enough redundancy be provided to match the reliability of an equivalent transmission line. For T&D project deferral, the degree of coincidence of distributed generation would apply when transmission and distribution credit is calculated.

N. External Contracts on LIPA Interfaces

The LIPA transmission and sub transmission system design is also affected by the terms of contracts entered by LIPA with Con Edison and NYPA, and through NYPA with three Long Island municipalities and other entities. LIPA has agreed to wheel NYPA electricity to NYPA's customers on Long Island pursuant to two transmission agreements. One is for the municipalities of Freeport, Greenport and Rockville Centre and the other is for Brookhaven National Laboratory. While NYPA has the ability to wheel power to its Long Island customers over its own Y49 facility, it cannot require LIPA to provide such wheeling over Y50, even if this would lower costs to NYPA and/or its customers.

Use of circuit Y50, the 345 kV interconnection between Dunwoodie substation (Con Edison) and Shore Road Substation (LIPA), is governed by an agreement signed on September 19, 1988[24] which has been amended from time to time.

The following table is a summary of the transmission contracts that are in effect between LIPA and NYPA.

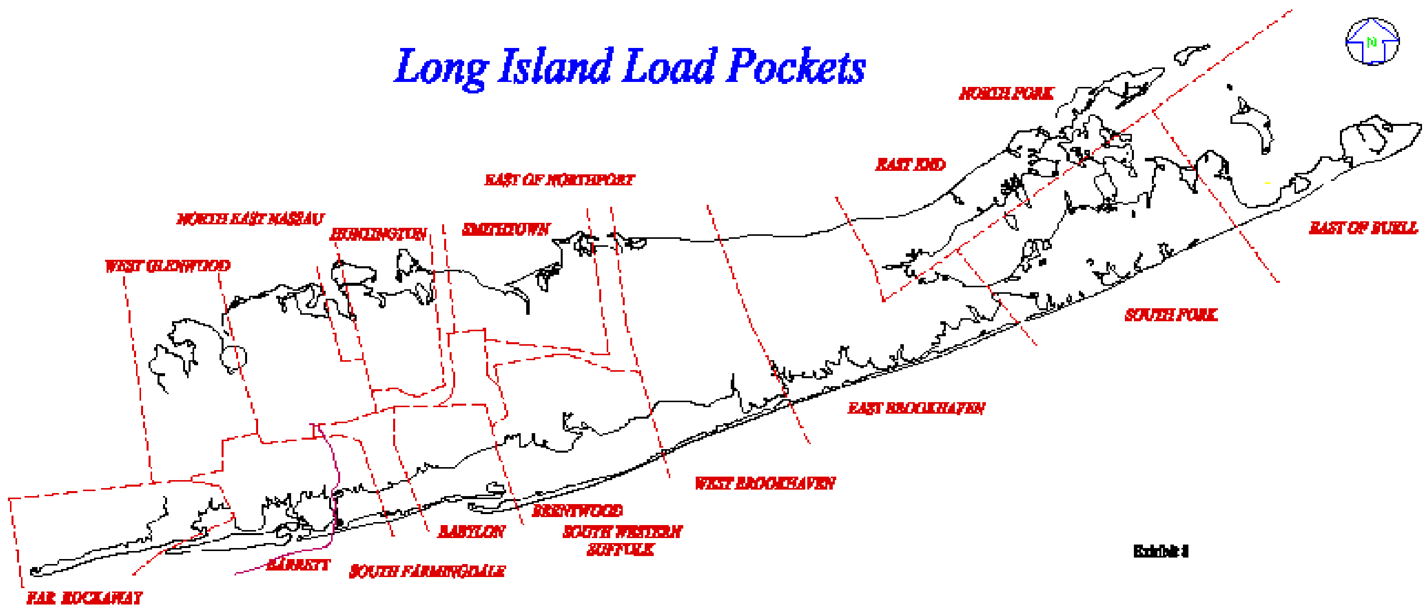
[24] This agreement superseded the original Letter of Agreement signed on April 4, 1975 and its amendments.

Table 4 LIPA -- NYPA Transmission Contracts

LIPA– NYPA Contract Title	Contract Date	Term of Contract
Municipals: Freeport, Rockville Centre and Greenport	7/1/99	10/31/13
Brookhaven National Laboratory	10/1/81	See Note 1
Economic Development Power	6/1/91	See Note 1
Blenheim-Gilboa	4/1/89	See Note 2
Sound Cable Project (Y49)	8/26/87	See Note 3

(1) Contract may be terminated by either party on 2 years' written notice
(2) Contract may be terminated upon 90 days written notice by LIPA
(3) Final retirement of NYPA obligations to finance or refinance the cable and thereafter, upon mutual agreement of the parties. The cable debt is expected to be amortized by 2020.

Exhibit 8 Long Island Load Pockets



O. System Separation Event and Restoration Design

The US – Canada Task Force created to study the causes of the August 14, 2003 blackout issued an interim technical report in November 2003. The report examined the causes and made recommendations on a wide range of actions needed to reduce the possibility of such an outage occurring in the future.

Coincident failures of generating units, transmission lines or transformers while improbable, can degrade bulk electric system reliability. Transmission planners and system operators need to regularly communicate and discuss potential actions that will preserve the reliability of the LIPA electric system.

Based on transmission system computer models prepared by NERC, LIPA transmission planners will conduct power flow and transient stability analyses to identify system conditions that might require isolation of the LIPA system from electric systems outside its service territory. Procedures to separate the system and to restore it back in the unlikely event of another blackout will result from these studies.

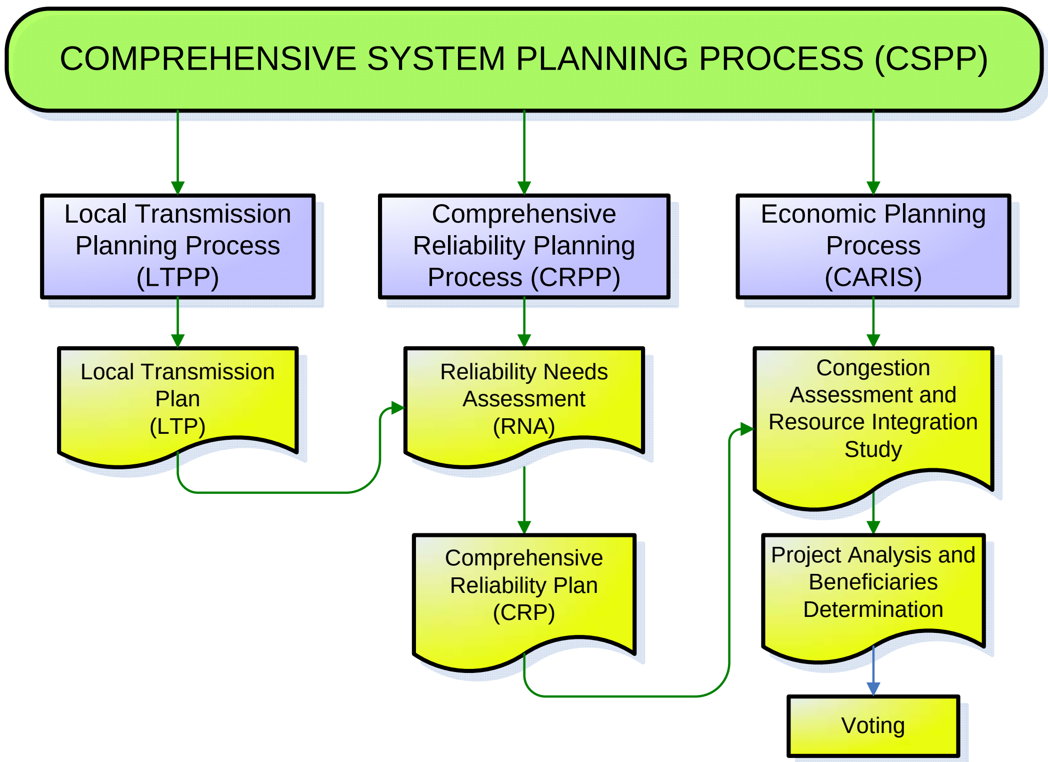
P. Integration of NYISO Comprehensive System Planning Process (CSPP)

Attachment Y of the NYISO Open Access Transmission Tariff (OATT) describes the process that the NYISO, the Transmission Owners, and Market Participants shall follow for planning to meet the reliability needs of the New York State Bulk Power Transmission Facilities ("BPTFs"). The objectives of the process are to: (1) evaluate the reliability needs of the BPTFs; (2) identify, through the development of appropriate scenarios, factors and issues that might adversely impact the reliability of the BPTFs; (3) provide a process whereby solutions to identified needs are proposed, evaluated, and implemented in a timely manner to ensure the reliability of the system; (4) provide an opportunity for the development of market-based solutions while ensuring the reliability of the BPTFs; and (5) coordinate the NYISO's reliability assessments with Neighboring Control Areas.

On October 16, 2008, in response to its Order 890 compliance filing, the Federal Energy Regulatory Commission (FERC) conditionally approved the NYISO's newly expanded planning process called the Comprehensive System Planning Process (CSPP). This process integrates the previous Comprehensive Reliability Planning Process (CRPP), as well as a new Congestion Assessment and Resource Integration Study (CARIS) CARIS, into an extended two-year planning cycle. The CRPP encompasses a ten-year planning horizon and evaluates the future reliability of the New York bulk power system. As part of the CRPP, to preserve and maintain system reliability, the NYISO, in conjunction with Market Participants, identifies the reliability needs over the planning period and issues its findings in the Reliability Needs Assessment (RNA). The Comprehensive Reliability Plan (CRP) evaluates a range of proposed solutions to address the needs identified in the RNA. The final portion of the CSPP is the Local Transmission Owners (TO) Planning Process (LTPP) where all NY State TOs provide details of their long term transmission plans including criteria, models, and local area development. LIPA submitted its Local Transmission Plan (LTP) to Market Participants[25]. See Exhibit 9 for a flow diagram of the process.

[25] LIPA's LTP is posted on its website, http://www.lipower.org/company/papers/ltpp.html

Exhibit 9 NYISO Comprehensive System Planning Processs



The NYISO offers the 2009 CRP in accordance with its tariff obligations and also to update ongoing initiatives of the New York Public Service Commission (NYSPSC), the New York State Department.

Information regarding the procedures for the implementation and administration of the CSPP and its components are included in the NYISO's manuals. They establish a schedule for the collection and submission of data and the preparation of models to be used in the required studies. The procedures are designed to allow the coordination of the NYISO's planning activities with those of NERC, NPCC, and other regional reliability organizations so as to develop consistency of the models, databases, and assumptions utilized in making reliability determinations.

As Transmission Owner, LIPA is responsible for reviewing the data used to model its existing transmission system and for submitting its transmission expansion plans to the NYISO to be included in the planning process. The NYISO reviews all Transmission Owners' plans to determine whether they meet Reliability Needs, recommends an alternate means to resolve the needs from a regional perspective, where appropriate, or indicate that it is not in agreement with a Transmission Owner's proposed additions.

The latest versions of the NYISO planning studies are available on the NYISO web site: http://www.nyiso.com. See also NYISO's Transmission Expansion and Interconnection Manual (See Appendix 4.)

Q. Blackout Lessons Learned

As a result of the August 14, 2003 Blackout and follow up investigations, several initiatives have been identified. This section addresses several of these initiatives.

1. Eastern Interconnection Phasor Project (EIPP)

DOE initiated the Eastern Interconnection Phasor Project (EIPP) after August 14, 2003 Blackout. This project supports the NERC blackout recommendations and will provide greater visibility of system conditions to system operators to allow monitoring a wider area and for keeping an eye on other systems as well.

The system will monitor the Eastern Interconnection with GPS-synchronized telemetering devices and the communication set up for various Online and Offline applications to increase Power System Reliability and Security of the Eastern Interconnection.

Expected Benefits are:

- Faster detection of outages
- Automatic responses to outages
- Improvement in grid security by introduction of rapid restoration systems
- Greater integration of information and electric technologies resulting in strengthened security.

LIPA currently has one Phasor Measurement Unit (PMU) in operation, installed at the East Garden City 138 kV substation. The real time voltage magnitude and angle can be seen via a web service program using any internet browser. LIPA is considering installing additional PMU at some of its other substations on the 138 and 69 kV systems. This will give a better overall picture of system conditions. LIPA is also participating in a NYISO statewide transmission system Phasor Measurement Network (PMN) that was selected by the Department of Energy (DOE) as part of the smart Grid Investment Grant Program. (See Smart Grid section)

As part of the EIPP, LIPA also utilizes the Real Time Dynamics Monitoring System (RTDMS) which provides phase angle and voltage data for the entire Eastern Interconnection. This data can be used for monitoring and event recreation.

2. Pump Houses

A total of 17 LIPA substations equipped with dielectric fluid pump houses are utilized on 54-pipe type cable and self-contained fluid cable systems. Pump houses are designed for various operations. Depending upon the required application, pump houses are equipped with multiple pumps and valving systems to maintain elevated pressure in the underground transmission cable system, and/or to flow the dielectric fluid through the cable system.

Based upon the design of the cable, pressurizing pumps are utilized and operated in an automatic mode to maintain elevated pressure within the cable. LIPA high-pressure cable systems achieve operating pressures of approximately 200 – 250 psig.

Some cable systems designed to circulate dielectric fluid achieve higher cable ampacity ratings and are also equipped with circulation pumps having flow rates of 10 – 20 gpm.

Pump houses are equipped with redundant pumps for back up purposes in case the primary pump fails and with special relief valving to protect against over pressure conditions.

Monitoring, annunciator, and alarm systems exist that take cable system pressures and fluid storage tank volumes and automatically transmit information to the electric system operations control room in the event of system malfunction.

Each pump house is also equipped with fluid storage tanks ranging in size from 2500 gallons to 30,000 gallons. A total of 45 fluid storage tanks exist on the LIPA system.

In order to provide supplemental electrical supply back up capability, the pump houses are also equipped with back up diesel generators and automatic throw over (ATO) switches for continued operation during power failure conditions.

Refer to LIPA's "Spill Prevention Control and Countermeasure Plan (SPCC)" for Fluid Filled Cable Systems for additional information on LIPA pump houses and fluid filled cable systems. This plan is developed to comply with Federal requirements of 40 CFR 112.3d.

R. Interconnection Procedures for Large, Small, and Intermittent Generators

1. Small Generator Interconnection

It is anticipated that technical interconnection requirements for small generators, i.e., not exceeding 20 MW, will be addressed at two levels. These levels will be 2 MW and smaller including net metered interconnections; and greater than 2 MW but not exceeding 20 MW.

Interconnection procedures for generation 2 MW or less will follow the general outline of the New York Standardized Interconnection Requirements. Procedures for generation greater than 2 MW but not exceeding 20 MW will follow the general outline of the FERC Small Generator Interconnection procedures.

2. Large Generator Interconnection

Large Generators are defined as generators exceeding a 20 MW nameplate rating. LIPA follows the Large Generator Interconnection Procedures as defined by the New York Independent System Operator (NYISO) in Attachments S and X. Generators will interconnect with LIPA’s transmission system utilizing LIPA’s Requirements for Generating Facility Interconnection to the LIPA Transmission System, Bulk Power System Facility and End User Interconnection Requirements to the LIPA Transmission System, and LIPA’s Revenue Metering Requirements for Generating Facilities Interconnecting to the LIPA Transmission System.

For power sources supplying Large Generators, LIPA requires adherence to the Northeast Power Coordinating Council (NPCC) requirement for Bulk Power System station service AC supply. This requirement states:

"On bulk power system facilities, there shall be two sources of station AC supply, each capable of carrying at least all the critical loads associated with protection systems".

The two power sources shall not be subjected to a single contingency or to a common mode failure.

a. Disturbance Ride Through

All generating units greater than 20 MW that are connected to LIPA's transmission system, 69 kV and above, shall be designed to stay connected and operate through system disturbances, *i.e., ride through*. Absent system disturbances that result in the direct disconnection of the generator due to primary clearing, or backup fault clearing in the case of primary failure, all generating units should be designed to withstand the specific design criteria contingencies that are outlined in Exhibit 6 at projected demand levels and anticipated power transfer levels. This applies to, but is not limited to, conditions such as low voltage, phase and power swings.

The ability to *ride through* an event is critical to maintaining system stability, preventing voltage collapse and eliminating thermal overloads. The tripping of a unit and / or any reduction in output (e.g., run-back) during a disturbance can result in further exacerbating the impact of a disturbance on the electric system at a time of system weakness. This is not to preclude protection of the generator equipment. However, information regarding all devices that could affect unit operation or result in the ultimate change in operation of the generator must be provided to LIPA and approved by LIPA before interconnection of the generator will be allowed. This includes all electrical and mechanical components that are outside of the normal electric relaying review process and can include other equipment related to emissions, fuel supply, etc.

3. Intermittent Generator Interconnections

As defined under Small and Large Interconnections above, LIPA will follow the Procedures and utilize the Interconnection Requirements appropriate for the total nameplate rating of the intermittent generation projects, such as wind and solar, that are being proposed. These projects are typically interconnected through DC inverters. (See Power Factor Criteria)

4. Low Voltage Ride Through

FERC Order 661-A imposes Low Voltage Ride Through (LVRT) requirements on all new wind projects. These requirements should address LIPA's interests if the wind farm does not place a heavy VAR demand on the system during recovery. Verification of the LVRT is part of the project system reliability impact study and developer's functional performance testing. Other intermittent sources shall also comply to this requirement.

S. LOSS OF LARGEST SYSTEM RESOURCE (INTERCONNECTION OR GENERATING UNIT)

LIPA designs its system to withstand the loss of the largest resource on its system to comply with NYSRC rules. Studies shall consider the impact of the contingency loss on both planning and operating needs including need for additional operating reserves and limitations to import/export of power to Long Island. The studies shall also consider any economic impacts resulting from changes to these requirements as well as possible assignment of cost responsibility.

NYISO also considers the impact of the loss of units on its statewide requirements.

T. STORM HARDENING POLICY

Severe storms pose a high risk to Long Island's electric power system. Recognizing this threat, LIPA adopted a proactive policy in 2006 to address the threat of severe storms and has launched a long-term program anticipated to cost up to $500 million over 20 years to improve the capability of the electric system on Long Island to withstand the impacts of hurricanes and other severe storms, and to shorten the time required to restore service to customers when outages occur due to storms. LIPA's policy incorporates three main thrusts: 1) improve the ability to withstand severe storms without damage (durability); 2) improve the ability to continue service despite some system damage (resilience); and 3) reduce the time necessary to recovery when service is disrupted (restoration). LIPA's policy is targeted at impacts of major hurricanes, not just routine storms.

The durability efforts may include reconfiguration or reconstruction of substations to avoid damage from flooding and wind, improve transmission line design and construction to withstand high winds, improve distribution design and construction to withstand high winds. Resilience efforts may include leveraging LIPA's distribution automation system to manage the scope of outages and employing distributed generation and microgrids. Restoration efforts may include proactively de-energizing circuits, implementation of outage management system, improvement of voice and data communication channels, implementation of a resource control system, implementation of an electronic damage inventory system, improvement of damage assessment processes, improvement of the restoration management system, improvement of restoration logistics processes, development of human resources support to ensure employee commitment to the restoration effort, and ensuring effective contractor response.

No program can assure that severe storms will not cause power outages, but LIPA believes that implementation of its policy will both reduce the degree of damage and enable faster restoration when outages do occur.

U. Transient Network Analysis (TNA)

Whenever new underground cables or FACTs are planned, a Transient Network Analysis (TNA) study confined to the area of expansion is commissioned. The TNA study will evaluate:

- short circuit currents
- load flow voltage profiles
- harmonic resonances
- changes in bus voltages
- temporary overvoltages
- transient voltages and currents

The study will also provide information to finalize substation configuration and critical decisions in the selection of transformer winding configuration, the need for grounding transformer, shunt or series reactors, type and rating of surge arrestors, circuit breakers and control and protection strategies.

V. Harmonics

Harmonics on the power system are defined as the sinusoidal voltage and currents at frequencies that are integer multiples of the fundamental frequency. The most common harmonic index, which relates to the voltage waveform, is the Total Harmonic Distortion (THD), which is defined as the root mean square (R.M.S.) of the harmonics expressed as a percentage of the fundamental component. Harmonics are injected into power systems by large power electronic transmission equipment (e.g., FACTS, HVDC, etc.), certain large industrial loads, and by the aggregate injection of the pervasive penetration of distorting consumer loads such as home entertainment, electronically-ballasted lighting, variable speed HVAC equipment, etc. Measurements taken indicate that there is a substantial level of background harmonic distortion throughout the LIPA system, most notable the fifth harmonic. LIPA uses IEEE standard 519 which establishes IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems as a guideline for establishing it criteria, LIPA requires the total voltage distortion at any point of interconnection for 69 kV and above buses on Long Island shall be less than 1% for any individual harmonic and less than 3% for the root sum-square total of all harmonics orders two to fifty (THD).

In addition, the aggregate harmonic current into a point of interconnection from devices shall be limited such that the IT product is less than 3000 as defined below

$$IT = (\Sigma_h (Th \cdot Ih)^2)^{1/2}$$

where:

Th = Telephone interference weighting factor (TIF) from IEEE Standard 519-1992 for harmonic order *h*

Ih = RMS magnitude of the harmonic current from the aggregation of all devices connected at a Point of Interconnection at harmonic *h*.

Devices contributing to harmonics that are connected to lower voltages shall also be investigated to determine if corrective actions are required.

VI. Distribution System Design Criteria

This section describes the criteria and methodology used to design the LIPA distribution system. When performing distribution system analyses, the following alternatives will be evaluated for solving the particular need:

1. Increased voltage for distribution systems (e.g., 4 kV to 13 kV)
2. Distributed generation
3. Controllable load
4. Energy storage devices

A. Distribution Substation Transformers

Distribution Substation Transformers are rated for loading according to the American National Standards Institute (ANSI) standards for maximum internal hot spot and top oil temperatures as detailed in the IEEE Guide for Loading Mineral-Oil-Immersed Power Transformers up to and including 100 MVA with 55 ^{0}C or 65 ^{0}C winding temperature rise (ANSI/IEEE C57.91 latest version). The manufacturer's factory test data and the experienced 24-hour loading curve data are used in an iterative computer program that calculates allowable loading levels. The transformer's "ratings" for the Normal (N), Long Term Emergency (LTE), and Short Term Emergency (STE) load levels are identified based upon maximum internal temperatures and selected values for the loss of the transformer's life caused by its operation at the criteria temperatures for a specified duration, and on a defined load curve.

The ratings of transformers are calculated from their thermal heat transfer characteristics and the expected electric loading experience over a 24-hour cycle. All distribution substation transformer bank ratings are evaluated seasonally for their summer and winter values.

A substation transformer will not be loaded above its Normal rating during non-contingency operating periods. The maximum load for Normal operation of the transformer is determined and set when the operation of the transformer at that level for the peak hour in the 24-hour load cycle causes a cumulative (24 hour) 0.2% loss of Transformer life, or the Top Oil Temperature exceeds 110 ^{0}C, or the Hot Spot Copper temperature exceeds 180 ^{0}C. Conditions above any of these limitations will result in a shortening of the transformer service life beyond prescribed design levels and/or physical damage to the equipment.

1. First Contingency Emergency Design Criteria

For f*irst contingency emergency* conditions involving the loss of one distribution substation transformer in an existing two-bank configuration, when the distribution bus-tie breaker is closed, the following system design criteria applies:

- In cases where a first contingency situation causes the LTE rating of a companion transformer to be exceeded, all load above the LTE rating of the companion transformer must be transferred to peripheral facilities within two hours without exceeding the LTE rating of the substation transformers or distribution circuits, receiving the load. This could be accomplished by six manual load transfers or more if supervisory switching is available. The LTE rating of a substation transformer is determined and set when the 24 hour operation of the transformer, with that additional load in each of the hours in the 24 hour load cycle curve, causes a cumulative (24 hour) 3.0% loss of transformer life or the Top Oil temperature to exceed 130 ^{0}C, or the hot spot copper temperature to exceed 180 ^{0}C. The load on all energized facilities must be brought down below their Normal ratings before the 25th hour.

- In cases where a first contingency situation will cause the STE rating of a companion transformer to be exceeded, load must be immediately reduced (dropped/shed) to a level less than STE. Within two hours (for recovery planning, a maximum of six load transfers are used), all load between the LTE and STE ratings, and any load that was initially shed to get the companion transformer below its STE rating, must be transferred to peripheral facilities without exceeding the LTE rating of the substation transformers or the distribution circuits receiving the load. The STE rating of a transformer is determined and set when the one hour operation of the transformer at that level for the peak hour in the 24 hour load cycle causes a cumulative (24 hour) 3.0% Loss of Transformer Life or a hot spot copper temperature exceeding 180 ^{0}C. However, the maximum STE rating is limited to a value equal to twice the transformer's “nameplate” rating. The load on all energized facilities must be brought down below their Normal ratings before the 25th hour.

2. Low Voltage (13 kV or 4 kV Switchgear) Bus Tie Breaker Operation

To reduce momentary interruptions to customers and to reduce available fault currents on distribution circuits at two bank substations, the low voltage side of 4 kV or 13 kV distribution bus tie breakers is operated in the normally open position. This mode of operation will minimize overhead covered wire burn downs when short circuit currents are high enough to damage the covered wire before the instantaneous relay can clear the fault.

The exceptions to these design criteria are for distribution substations that supply a secondary network system or for substations where a load unbalance will occur on the individual transformers by opening the bus tie breaker resulting in a normal overload on one of the two transformers.

B. DISTRIBUTION CIRCUIT LOADING CRITERIA

The distribution feeders from each substation are in a "looped radial" configuration with provisions for transfer of load between feeders, including feeders from adjacent substations. During normal and emergency conditions, circuit loading must not exceed the capabilities of the distribution line conductors specified in LIPA's DA-10001 - Current Carrying Capacity Tables (See Appendix 7) or exceed any other limiting equipment which will be subjected to those load conditions.

1. First Contingency Emergency Design Criteria

For *first contingency emergency* conditions on a distribution circuit, the worst of which is the loss of the circuit's exit cable or circuit breaker **all interrupted load must be restored within one hour** (for recovery planning a maximum of three load transfers are used). After transfers, all resultant components must be below the LTE ratings as defined by the appropriate loading guides.

2. Main Line Sectionalizing Capabilities

Sectionalizing devices are installed on all circuits to isolate faulted conductors and to permit the circuits to be subdivided if required by contingencies. Normally open ties are provided between adjacent circuits to permit transfer of load during contingencies. Main line switching capabilities are incorporated in the design of all circuits in accordance with LIPA's DA-51015. *(See Appendix 7)*

3. Primary Circuit Voltage Drop Criteria

Under normal operating conditions, the voltage drop between the first distribution transformer of the circuit and the last one shall not exceed 5 volts (referred to secondary level) under maximum load condition.

Under contingency conditions, the voltage drop between the first distribution transformer of the circuit and the last one shall not exceed 8 volts (referred to secondary level).

The primary voltage drop design criteria under normal and contingency loading conditions is summarized in LIPA's Design and Application Standard DA-55001 – Electric Service Voltages *(See Appendix 7)*

4. Distribution Circuit Phase Imbalance Criteria

Adding new customer loads to the distribution circuit must be done in the manner to minimize phase imbalance on the distribution system and shall be in accordance with LIPA's GO-62 (see Appendix 7). In addition, existing feeders will be reviewed as per LIPA's GO-62.

This criterion is established to limit the load imbalance among the three phases of a primary distribution circuit. Such an imbalance gives rise to return current through the neutral conductor which contributes towards additional losses. Heavily loaded phases overstress the conductors reducing their life and can also lead to their eventual burn out even at low loadings of the circuit.

These criteria call for the correction of phase imbalances of existing and new distribution circuits. Phase imbalance is defined on the basis of connected KVA (CKVA) load for that circuit as,

$$\%\text{Imbalance}^{26} = \frac{(\text{phase load} - \text{average phase load})}{\text{average phase load}} * 100$$

[26] See GO-62 Distribution Circuit Balancing

Two criteria must be met for the circuit to be considered for corrective action.

1. The three phase current average for the circuit must exceed 50% of the circuit's current carrying capability.

2. One phase current must exceed the three phase current average of the circuit by 15%.

Accordingly, a single phase imbalance below 15% can be acceptable, since the phase loadings alternate themselves somewhat during the daily load cycle, such that the average loading on the circuit will be balanced. Any circuit violating these criteria will be monitored to get actual loading data, and will be corrected if the imbalance is verified. Any new load addition to a circuit should adhere to these criteria.

For all new single phase load additions, the new installation should be connected to the phase with the least connected KVA, if it is available, to maintain a balanced circuit.

C. DISTRIBUTION CIRCUIT REINFORCEMENT CRITERIA

In order to meet design criteria to provide the capacity to serve the load growth from new customers or the load additions of existing customers, and to improve service reliability to all customers, LIPA has established five programs for the reinforcement and improvement of distribution lines. They are:

1. Conversion and Reinforcement (C&R) Program

These are distribution line projects that provide increased distribution circuit capacity, or improve transfer capability between substations and/or circuits for meeting forecasted normal and contingency load conditions on these facilities. The improvements include primarily replacing the three phase circuit main conductors beyond the substation exit cable, or installing new mainline facilities such as overhead conductors, underground cables and switches.

2. Circuit Improvement Program

The Circuit Improvement Program involves an analysis of the causes of interruptions on those circuits experiencing below average reliability levels, and selecting candidate circuits for improvement. It involves a detailed field inspection of the entire circuit which identifies for corrective action all substandard conditions that are likely to cause interruptions. The field survey enables the development of customized improvements that may not have been apparent from an office analysis of interruption data. In addition to identifying substandard conditions, other reliability improvement programs such as tree trim, installation of MOV lightning arrestors, and the replacement of armless insulators, hot line clamps, and automatic-style wire splices are applied to these circuits as appropriate to further enhance reliability. Historically, the reliability performance of circuits targeted under the Circuit Improvement Program has experienced a significant improvement over the past several years compared to the untargeted circuits.

3. Control & Sectionalizing Program (ASU Installation Program)

The Automatic Sectionalizing Unit (ASU) Program involves the installation of supervisory controlled auto-sectionalizing switches at or near the mid-point and end-point (tie-point) of distribution circuits which provide automatic sectionalizing of downstream faults and operator controlled switching to sectionalize and restore portions of faulted circuits. This limits the number of customers interrupted when a main line fault occurs. Also, on select circuits with above average numbers of connected customers, additional ASUs are installed in series, breaking up the large load centers into smaller components. This results in an increase in overall circuit reliability due to a smaller number of customers experiencing a sustained interruption during a mainline fault, and increased flexibility in operating the Electric Distribution System.

4. Underground Cable Replacement Program

The Cable Replacement Program replaces existing three phase underground mainline exit cables and mainline underground dips that have been prioritized for replacement based on their field condition and historical risk factor such as recent failure history. Late in 2004, LIPA began testing cables to better determine their field condition. In 2005, all primary underground cables having higher historical risk factors were eligible for testing. Exit cables with no known failures are now proactively being tested as to their field condition. Considering the large quantity of aging exit cables on the LIPA system, and the fact that an exit cable failure typically interrupts the entire circuit, exit cables remain a priority. The cable test results are being analyzed in conjunction with historical data to better manage LIPA's cable assets in order to reduce outages while improving cost effectiveness of the program.

5. Distribution Capacitor Program

The need to add new capacitors to the distribution system is based largely on the System Load Forecast which is produced annually. As new loads are added to the system, additional capacitors are generally required to supply the additional reactive load to maintain voltage, reduce losses, and decrease loading. Capacitor application permits the maximum increase in KW carrying capacity of the line as well as maximum reduction in energy losses. These requirements are determined through the "Reactive Resource Study" a yearly examination of the system's needs and its ability to meet the demands of annual MW and MVAR load growth.

D. DISTRIBUTION CIRCUIT UNDER GROUNDING POLICY

Over 90% of the annual number of customer interruptions on the LIPA distribution system occur on overhead construction and outage data indicates that underground construction is more reliable compared to overhead construction.

Although the fault rates for overhead primary distribution equipment including failures for transformers, taps, clamps, insulator problems, etc. and for primary underground equipment including underground cables, cable terminations, splices, transformers, etc. are similar (approximately 11 faults per 100 miles), *the real advantage of underground construction is less exposure to outages related to external factors* such as inclement weather, trees, animals and motor vehicle accidents which has the potential to significantly reduce customer interruptions. The risk of these types of outages would be avoided if overhead circuits were to be placed underground. In fact, *historical electric interruption data indicates that the frequency of outages to customers supplied by underground circuits is approximately four to five times lower than for overhead systems. However it also takes four to five times longer to repair. As a result the net CAIDI is about the same for overhead and underground distribution.*

A “worst circuit” performance approach is used to identify those circuits with the worst reliability indices that is, where their SAIFI, CAIDI, SAIDI and MAIFI significantly exceed distribution circuit averages.

LIPA proceeds as follows in determining if a distribution circuit should be under grounded:

1. Identify “worst” or “outlier performing” circuits (3 std. dev. > mean)

2. Calculate the net reduction in customer interruptions and subsequently the cost effectiveness of existing reliability programs for these circuits.

3. If traditional reliability programs are unable to drive the reliability indices down to an acceptable level calculate the projected cost effectiveness ($/ Customer Interruption Saved) and reliability index improvement if these circuits were under grounded.

4. If the circuit reliability is greatly improved (within a certain bandwidth of cost effectiveness) the circuit or a portion of the circuit would be recommended for under grounding.

5. This recommendation is then reviewed with Operations as to the electric system and customer impacts of under grounding the facilities. Negative impacts of constructing, operating and maintaining the proposed underground facilities may outweigh the potential benefits of the project.

E. POWER QUALITY / FLICKER

The term (PQ) Power Quality has recently achieved a high level of visibility due to the emergence of the digital economy. Today, there is widespread use of digitally controlled devices in all areas of LIPA's customer equipment. Many of these new devices are highly sensitive and may not operate properly in the event of voltage variations or disruptions such as voltage spikes, sags or dips.

Service Voltage levels are provided within a steady-state tolerance range as per ANSI C84.1. This specification requires that voltage be provided within +/- 5% of the nominal voltage level.

Voltage dips or spikes and brief service interruptions of varying duration and severity occur due to operating conditions on the electric system. These irregularities do not cause malfunction of lighting or motor loads but may affect computers or similar equipment. Consequences of these irregularities are discussed in the Power Quality Section of the LIPA Red Book which is available on LIPA's website.

F. DISTRIBUTION LOAD POCKET SUPPLY CRITERIA

1. Single Supply Distribution Load Area/Pocket

Single supply distribution load area represents a portion of the primary distribution circuit that does not have an alternate supply to serve customers after a fault occurs on the main supply line. Customers can only be returned to service after the faulted portion of the main supply is repaired.

When the number of customers located in a single supply load area, exceed the average number of customers supplied by LIPA's 13 kV distribution circuit of 1300 customers, the feasibility to provide a second supply will be evaluated and recommendation to eliminate the load pocket or reduce the number of customer inside the load pocket will be presented to LIPA.

2. Multiple Supply Distribution Load Area

Multiple supply distribution load area represents a portion of the primary distribution circuit located between two or more switching devices.

If the number of customers supplied by the multiple supply load area exceeds the average number of customers of LIPA's 13 kV distribution circuits, service restoration, after the faulted section of the primary distribution circuit is isolated, shall be accomplished by remote supervisory controlled switching devices.

The objective is to reduce the longer customer outage time that could result from manual switching. Recommendation plans to reduce switching times will be presented for LIPA's review, and consideration to implement.

G. DISTRIBUTION SYSTEM EFFICIENCY AND LOSSES.

The reduction of system losses is one of the major goals of the design and operation of the LIPA T&D system. LIPA combines several approaches to accomplish this on primary distribution system and one of the ways it achieves this is through balancing three phase load. LIPA established an annual program to correct phase imbalances (GO-62: "*Distribution Circuit Load Balancing Procedure*"). The program is prioritized to accomplish the greatest loss reduction and it also addresses the mitigation of individual normal and contingency phase overloads.

Reactive additions are also implemented to maintain voltage regulation and to reduce losses on the primary distribution system and are evaluated as part of the Annual Ten Year Reactive Reserve study.

VII. Substation Design Criteria

This section describes the criteria and methodology used in the design of LIPA substations. These criteria are currently being reviewed for both transmission and distribution substations by analyzing the impact on service reliability of different breaker/line/transformer arrangements at a substation using new computer assisted techniques.

The transmission and distribution systems are designed to minimize the interruption time to customers. Automatic switching, circuit switches on banks, motor operated controls, and the dispatch of multi-operators for field switching are incorporated in the LIPA design to ensure the timely restoration of service. The various bus configurations are shown for transmission substations in Section III Exhibits 3-5 and for distribution substations in Section VII.B Exhibits 10-13.

Distribution system design requires the recovery after a failure of a substation bank or distribution feeder to pick up the interrupted load through the automatic operation of field equipment, such as ASUs, and the dispatch of personnel to perform the necessary switching operations to restore service. For the loss of a distribution feeder three switching operations within one hour are permitted to allow the receiving circuit to be brought below its LTE rating and then additional transfers to reach its normal rating within eight hours. For the loss of a substation transformer, six field switches are permitted within two hours to unload the receiving transformer to its LTE rating and then within 24 hours reduced to its normal rating. Refer to Section VI.B for further distribution loading criteria. Conversion and reinforcement capital programs are initiated to solve situations that can not meet these guidelines.

The design of the transmission system with ring-bus, I-bus, or breaker-and-a-half configurations considers the restoration of the system after a fault or interruption. For example, the lines off a ring bus use motor operated air break switches (MABS) to allow the opening of a line after tripping to enable the ring to be restored. As a result of the Blackout Study critical transmission substations have been equipped with black start generators to maintain SCADA and switching capability in case of a loss of power.

For loss of a single major component (usually a substation transformer) all interrupted load, or load above the Long Term Emergency (LTE) rating of equipment remaining in service for two (2) hours, must be transferred to adjacent substations within six manual transfers without exceeding the LTE ratings of substation transformers or feeders receiving the load.

In cases where studies indicate that a first contingency situation would cause the Short Term Emergency (STE) rating of a transformer to be exceeded, area reinforcement plans shall be developed to eliminate the STE problem.

Substation capacity additions must be made to meet load growth and to meet the design criteria. Existing substations are generally expanded to the design level before establishing new substations, particularly if the purchase of property is required. New transformer requirements are sized to accommodate 10-15 year capacity requirements assuming projected growth rates based on least cost planning principles. LIPA constrains itself to the use of single winding transformers, except in the unusual circumstance where space limits require the use of dual-winding transformers. Other factors to be considered include: environmental, governmental or customer objections and economics.

The following sections discuss specifics of transmission and distribution substations.

A. TRANSMISSION SUBSTATION DESIGN CRITERIA

345 kV and 138 kV substations, including those at power generating stations, are included in this Transmission category. Step-down transformers at these substations feed 69 kV or 33 kV sub-transmission lines emanating from the substations that supply neighboring distribution substations.

The traditional *"I"* bus design at these substations would be evaluated based on the number of circuits and step-down transformers or "elements" attached to the bus to determine if, modifications to either *"ring"* bus design or *"breaker-and-a-half"* design is feasible within the available space constraints. Where feasible, the design guidelines will be as follow:

- *For three (3) or less elements use "I" bus design (See Exhibit 3)*
- *From four (4) to eight (8) elements use "ring" bus design (See Exhibit 4)*
- *For nine (9) or more elements use "breaker-and-a-half" design (See Exhibit 5)*

B. DISTRIBUTION SUBSTATION DESIGN CRITERIA

The typical LIPA distribution substation consists of two different distribution transformers supplied by two transmission or sub-transmission lines. A high voltage bus tie breaker or two line breakers and a bus tie breaker usually protect these transformers from faults on the high voltage supply system. The transformer capacity is sized relative to their ability to pickup load as forecasted under normal weather criteria. As described in the *Contingency Design* section below, the objective has been to prevent losing both distribution transformers at the same time thus avoiding a customer outage.

Some substations have more than two distribution transformers and/or more than two power supplies. In order to improve service reliability, for new substations and when space is available for expansion at existing substations, the recommended LIPA distribution substation bus arrangement is based on the result of studies performed using a reliability evaluation computer program (SUBREL™). This program computes reliability indices and outage costs for different substation bus configurations.

The following exhibits describe bus arrangements considered for various combinations of substation transformers and incoming lines. They include “ring” and “I” bus designs for substations with:

- Two Incoming Lines/Two Transformer Banks (Exhibits 10 and 10A)
- Two Incoming Lines/Three Transformer Banks (Exhibit 11 and 11A)
- Three Incoming Lines/Two Transformer Banks (Exhibit 12 and 12A)
- Three Incoming Lines/Three Transformer Banks (Exhibit 13 and 13A)

Exhibit 10 LIPA Substation Design Two Incoming Lines / Two Transformer Banks

LIPA Substation Design
Two Incoming Lines / Two Transformer Banks

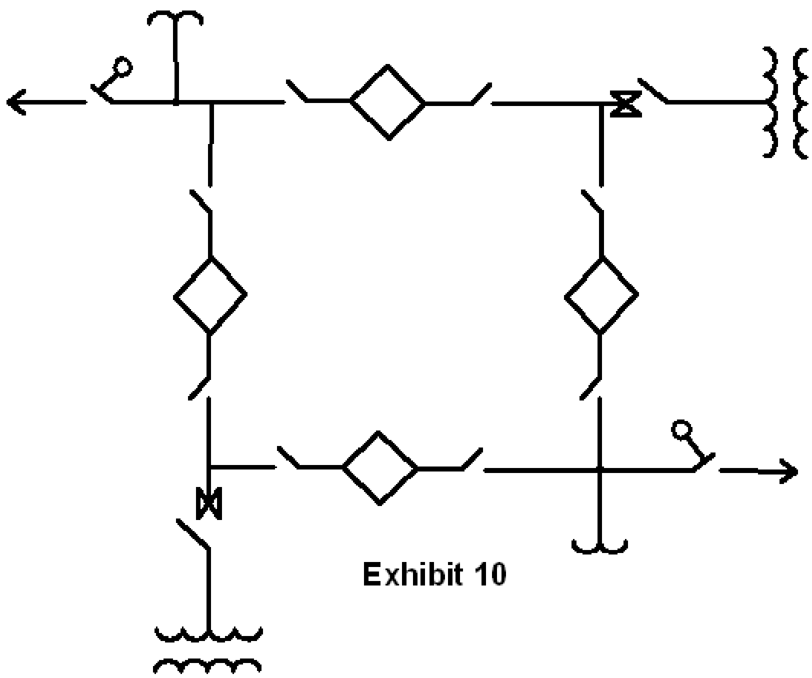


Exhibit 10

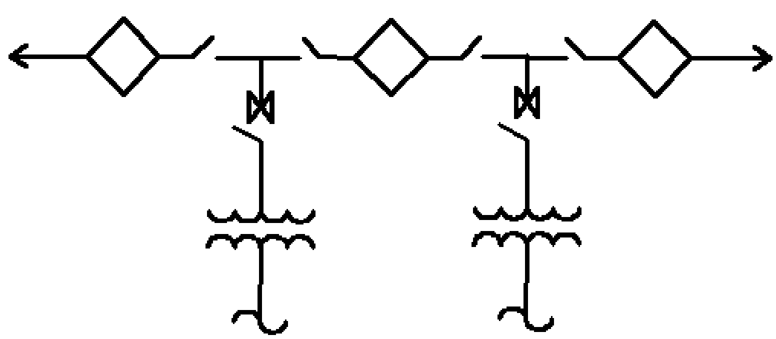


Exhibit 10A

Exhibit 11 LIPA Substation Design Two Incoming Lines / Three Transformer Banks

LIPA Substation Design
Two Incoming Lines / Three Transformer Banks

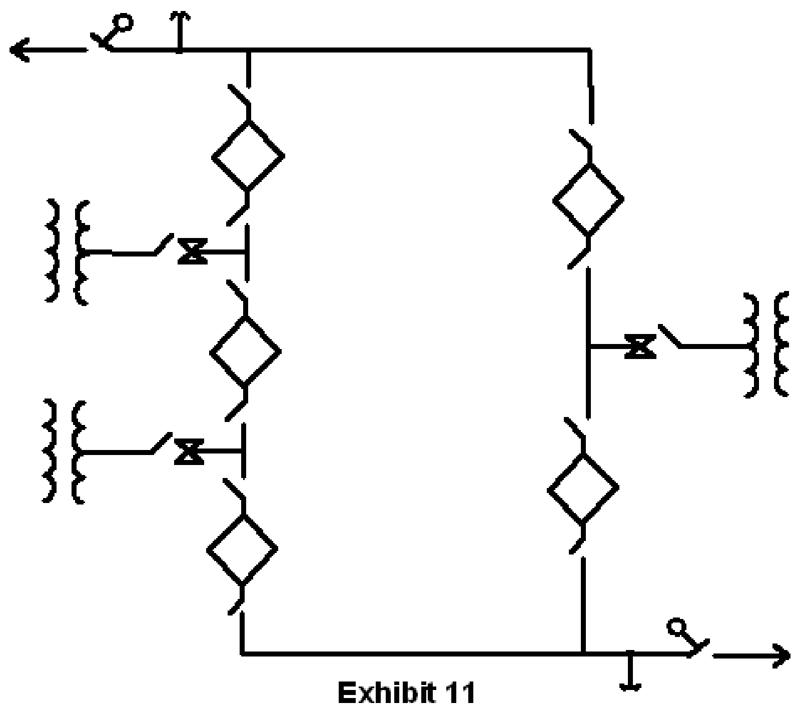


Exhibit 11

LEGEND

Existing

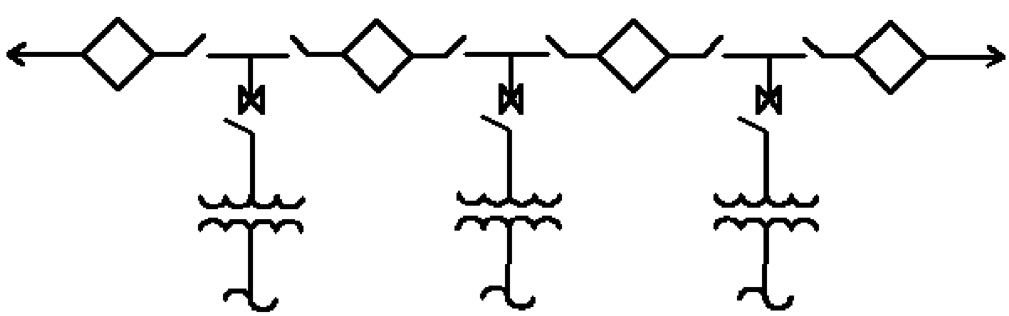


Exhibit 11A

Exhibit 12 LIPA Substation Design Three Incoming Lines / Two Transformer Banks

LIPA Substation Design
Three Incoming Lines / Two Transformer Banks

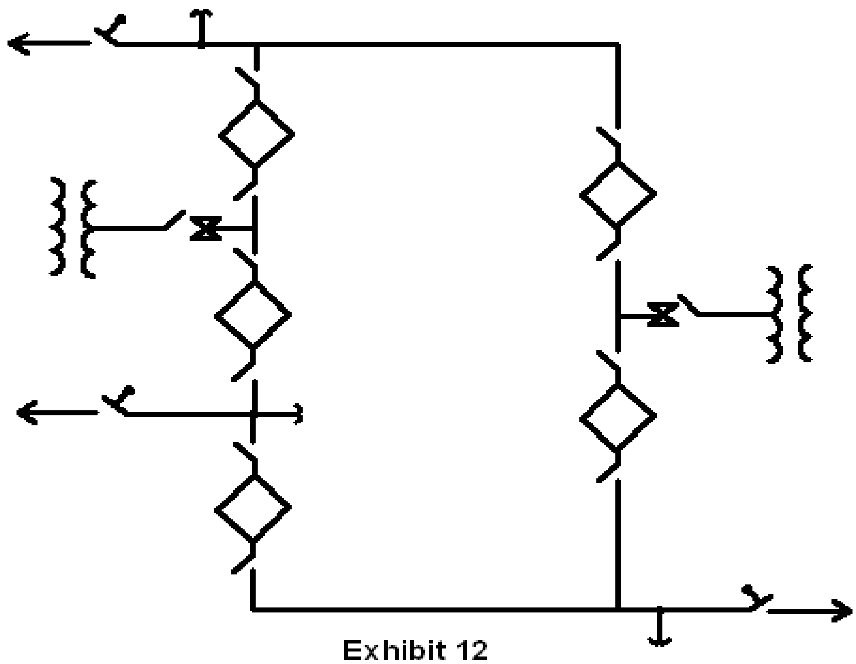


Exhibit 12

LEGEND

—— Existing

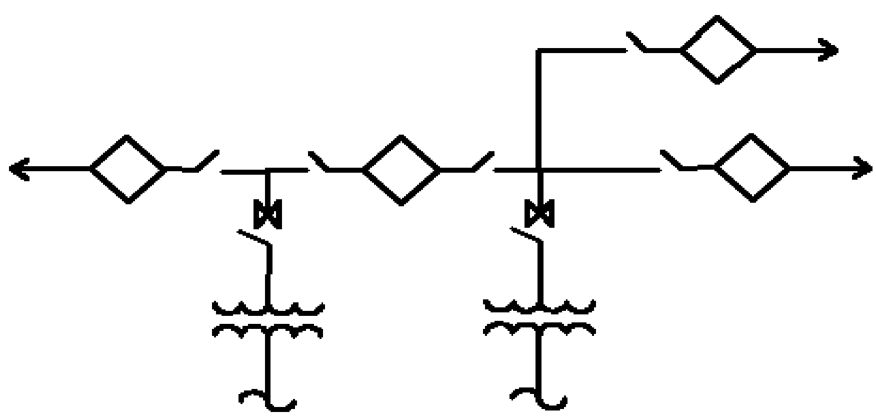
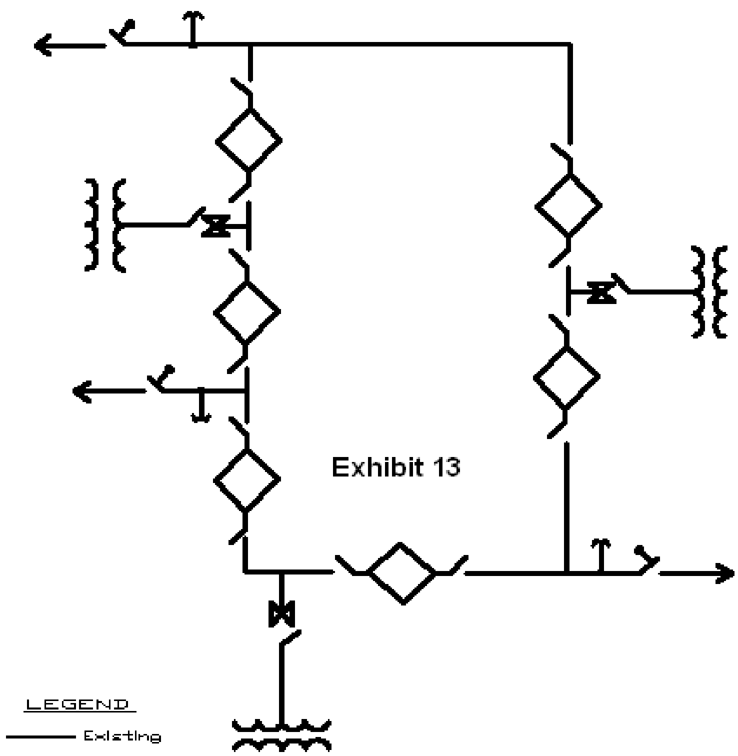


Exhibit 12A

Exhibit 13 LIPA Substation Design Three Incoming Lines / Three Transformer Banks

1.

LIPA Substation Design
Three Incoming Lines / Three Transformer Banks



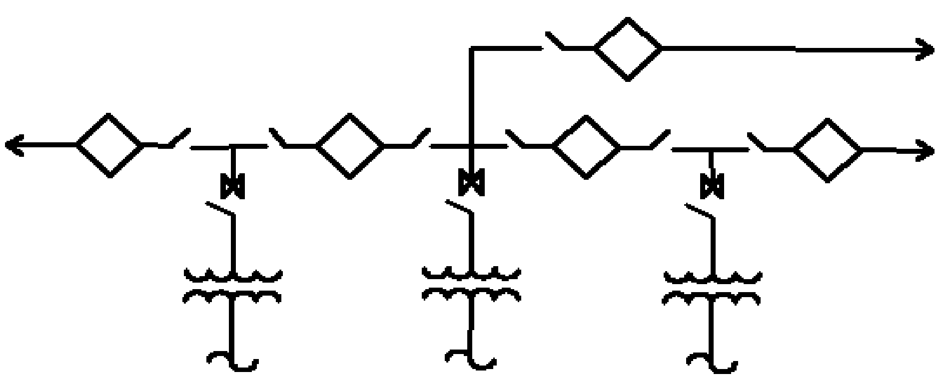


Exhibit 13A

4 kV Substations

The standard low side bus voltage for the LIPA distribution system is 13kV. Although some 4 kV substations exist, they total less than 10% of the system capacity. As 4 kV equipment condition approaches obsolescence and becomes inadequate to meet load growth, portions of the 4 kV system will be converted to 13 kV to maintain the load within the available 4 kV capacity. In general, no new installations of 4 kV equipment will be made and 4 kV will continue to remain on the system, essentially in isolated pockets, only as long as service reliability standards can be maintained and it continues to be economic to do so.

2. 13 kV Bus Design Criteria

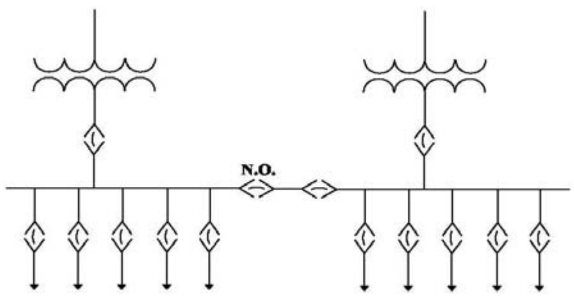
A full line-up of 13 kV switchgear, associated with a typical LIPA two-bank substation, consists of two 13 kV incoming breakers, two bus tie breakers and three to five distribution circuits on each half of the switchgear. One of the 13 kV bus tie breakers is usually operated in the normally open position in order to reduce fault current and momentary interruptions, except in those substations that supply distribution network load, or where open bus tie breakers would cause the load on one of the substation transformers to exceed the normal rating of that transformer.

At substations where a third or fourth distribution transformer will be installed, the associated switchgear for each transformer will consist of a 13 kV incoming breaker, a bus tie breaker and six 13 kV distribution circuit breakers, provided there are no space limitations within the existing substation property. The switchgear may be arranged in a ring configuration to provide higher reliability in the event of loss of one of the distribution substation transformers.

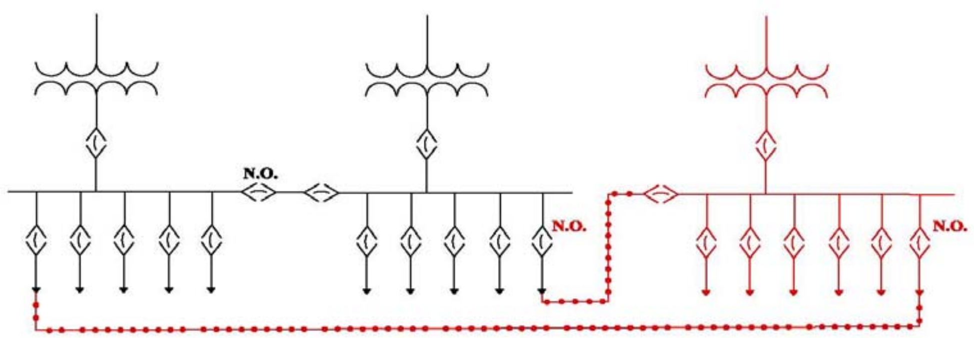
The following exhibit 14 describes 13 kV switchgear arrangements for various combinations of substation transformers.

Exhibit 14 LIPA 13kV Switchgear Arrangements

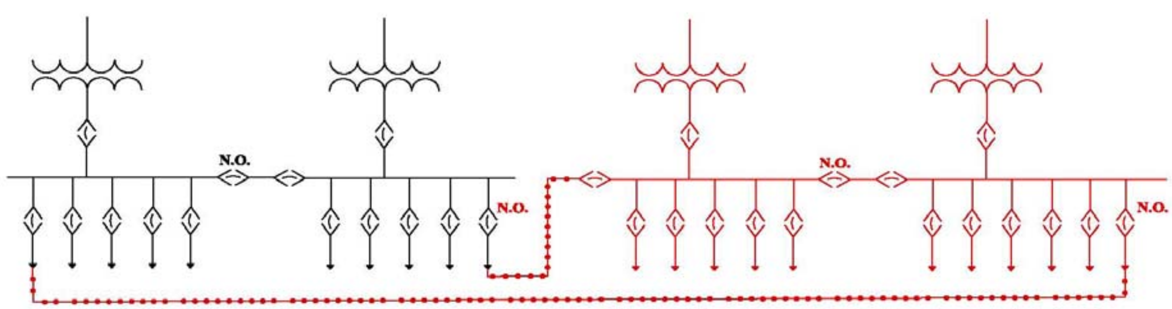
A. EXISTING 2 TRANSFORMER DISTRIBUTION SUBSTATION:



B. INSTALL THIRD DISTRIBUTION SUBSTATION TRANSFORMER:



C. INSTALL THIRD AND/OR FOURTH DISTRIBUTION SUBSTATION TRANSFORMER:



VIII. Deterministic versus Probabilistic Planning

A. Procedures when Normal Planning Standards can not be met

The design of the T&D System is intended to adhere to the NERC, NYISO and LIPA's planning criteria. However, in today's uncertain environment this may not always occur due to addition or retirement of facilities and time required to install replacements. The application of a deterministic standard may have to be abandoned for a specific event or piece of equipment if there is not enough time to make adequate system improvements to bring the system into compliance. If this is a necessary reason for not satisfying the standard, a probabilistic analysis will be utilized if possible. For example, it may be shown that the probability of a specific outage on the distribution system occurring during a critical operating period is acceptable so the system, at least for the short period of time, does not have to be designed to prevent or withstand that outage. The acceptable probability threshold might depend upon safety issues, how many customers are affected, how long they will be affected, the amount of equipment damage and how much it would cost to withstand, prevent or mitigate the outage. Alternatively, it might be shown that the probability of interrupting customer load, damaging equipment, etc. is less for a proposed design than it is for any other feasible alternative.

A special protection system (SPS) will be used judiciously and when employed, will be installed, consistent with good system design and operating policy. The decision to employ an SPS will take into account the complexity of the scheme and the consequences of correct or incorrect operation as well as its benefits.

B. Procedures In Addition to Normal Planning Standards

Consideration of events that are beyond normal planning standards shall be considered in evaluation of events. This would include analysis such as N-1-1, N-2 etc. These events although beyond criteria and may or may not be likely might have a significant impact. As such, LIPA may deem actions be taken to address these conditions. Programs such as EPRI's PRA can be used to determine these situations.

IX. Control and Protection Criteria

The main objective of the LIPA Electric System protective relaying schemes is to minimize the severity and extent of any electric system disturbance, limit potential equipment damage and meet all transient stability requirements as identified in transient stability studies. In addition, protective relaying schemes are designed to meet these requirements while experiencing a first-order contingency[27] protection system failure such as a relay failure to operate or a circuit breaker failure to trip.

This section outlines the design criteria for the protection systems associated with the LIPA electric system which is comprised of large steam turbine generator units, combustion turbine generators, substations, and transmission and sub transmission lines.

For a more detailed discussion on the topics covered in this section, refer to "Protection and Control Guidelines and Design Standards" (PTC-001-0). The following criteria are adapted pending the development of the above mentioned document.

A. DESIGN CRITERIA

The design criteria for each protective relay scheme are based on the following:

- *Reliability* – the ability of the relay to perform correctly when needed (dependability[28]) and to avoid unnecessary operations (security[29]).

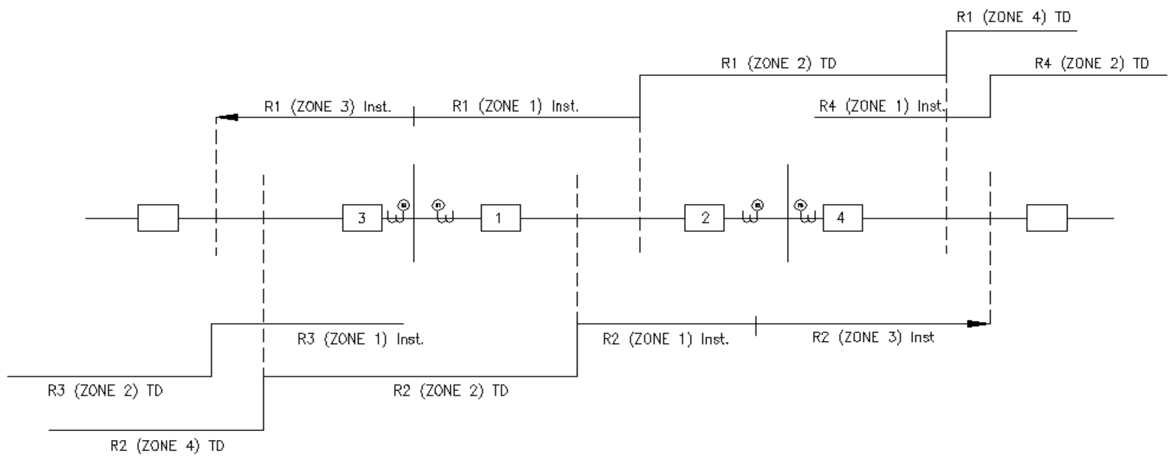
[27] First order contingency is the first event, usually involving the loss of one or more elements, which affects the power system.
[28] Dependability should be based on a single contingency, such that the failure of any one component of equipment (relay, current transformer, breaker, communication channel, etc.) will not result in failure to isolate the fault.
[29] System security should be maintained by limiting the complexity of the primary and backup relay protection schemes to avoid undue exposure to component failure.

- *Speed* – limit fault time and equipment damage.
- *Selectivity* – maximize service continuity with minimum system disconnect.
- *Sensitivity* – ability to sense minimum fault conditions without imposing limitations on circuit and equipment capabilities.
- *Economics*- required protection at minimum life-cycle cost.
- *Simplicity* – minimum equipment, circuitry and maintenance for required protection.

B. ZONES OF PROTECTION

The protection of the LIPA electric system is divided into overlapping zones of protection designed to provide high speed, selective, reliable clearing for three phase, phase to phase, phase to phase to ground, line to ground and arcing faults (Exhibit 15). Each zone consists of primary and back up relay systems designed to provide protection from the aforementioned faults, prevent common mode failure and meet all single contingency failure conditions. The protection of each zone includes relays that can provide back up for the relays protecting the adjacent equipment. The protection in each zone should overlap the adjacent zone; otherwise a protection void will exist between adjacent zones.

Exhibit 15 Zones of Protection



C. EQUIPMENT CONSIDERATIONS

In comparing protection design to the objectives and criteria set forth, consideration must be given to the type of equipment to be protected as well as the importance of this equipment to the system. While protection must not be defeated by the failure of a single component, several considerations should be weighed when judging the sophistication of the protection design:

- Type of equipment to be protected (e.g., bus, transformer, generator, lines, etc.).
- Importance of the equipment to the system (e.g., impact on transfer capability, generation, etc.).
- Replacement cost (and replacement time) of the protected equipment.
- Probability of a specific fault occurring.
- Protection design in a particular system may vary based upon judgment and experience.

D. Fault Probability

The majority of the system faults are line to ground faults and less than 10% percent are phase to phase or phase to phase to ground faults. Three phase faults hardly ever occur, however, the protection system must be able to cope with a three-phase fault.

Double circuit faults are rare when compared to the total number of faults on the system; however, they do occur and usually involve more than one phase. Direct lightning strikes can cause double circuit faults by striking a tower, circuit conductor or shield wire, which raises the ground potential at the associated towers.

E. Industry Standards

Protection of the LIPA T&D system conforms to the applicable version of the standards shown in Appendix 9.1.

F. Generation Protection Requirements

The protection requirements for generators interconnected to the LIPA system are outlined in the following LIPA Interconnection documents as included in Appendix 6:

- *Requirements for Generating Facility Interconnection to the LIPA Transmission System*
- *Bulk Power System Facility and End User Interconnection Requirements to the LIPA Transmission System*
- *Long Island Power Authority Interconnection Requirements for New Distributed Generation Greater than 300 KVA Operating in Parallel with LIPA's Radial Distribution System* (March 2003)
- *Long Island Power Authority Requirements for Interconnection of New Distributed Generation Units with Capacity of 300 KVA or Less to be Operated in Parallel with Radial Distribution Lines*

G. Transmission Line Protection

1. Faults

The protection of the LIPA electric system is designed to provide high speed, selective, reliable clearing of the following faults:

- Three phase faults
- Phase to phase faults
- Phase to phase to ground faults
- Line to ground faults
- Arcing Faults

The protection of each zone includes relays that can provide back up for the relays protecting the adjacent equipment. The protection in each zone should overlap the adjacent zone; otherwise a protection void will exist between adjacent zones (see Exhibit 15).

2. Primary Protection

The primary relaying system provides high speed clearing for all internal faults between the line circuit breakers. Simultaneous high speed clearing at each line end requires a pilot channel between the relaying systems.

Transmission line primary relaying is either solid state, microprocessor or electromechanical. Microprocessor relays also provide digital event recording, enhanced relaying functions, and remote communication capabilities.

Current differential relays over communication lines are used for primary protection where either dedicated fiber or a multiplexed channel is available at both line terminals.

Permissive overreaching transfer trip (POTT) or permissive under reaching transfer trip (PUTT) schemes using audio tones over telephone lease lines are also used for high speed relay protection. The fault sensing relays are impedance or directional overcurrent relays. Where dedicated fiber or multiplexing equipment is available, the permissive trip pilot channel will be fiber or a multiplexed pilot channel.

3. Dual Primary Protection

Dual Primary relay systems are based on two pilot channels. Dual Primary relay systems are required on bulk power inter ties and other transmission lines that require high speed clearing.

4. Backup Protection

The backup relaying is a non-pilot relaying system that is expected to operate simultaneously with the primary protection for non line end faults or with a time delay for line end faults.

Backup relaying for the current differential and the POTT and PUTT schemes are impedance phase and ground and directional ground overcurrent relays.

Independent CTs are used for backup protection when available.

5. High Impedance Fault Protection

A line to ground fault involving trees or high tower footing resistance may result in a high ground resistance. Also, a high arc resistance for line to ground or phase-to-phase faults can result in a high impedance fault.

Fault resistance is less important for pilot relay applications because the overreaching units can operate for most impedance values encountered. When the pilot channel is not available, phase and ground Zones 2 and 3 and ground time overcurrent devices provide delayed clearing for a high impedance fault. With the reduced fault magnitude, longer fault clearing times can usually be tolerated.

6. Switch-Onto-Fault Protection

Switch-onto-fault protection is also known as line pickup protection. This provides tripping in the event that the breaker is closed into a line fault, such as occurs if the grounding chains were left on the line following maintenance. In this case the directional impedance relays cannot instantly recognize the direction of the fault when the PTs are located on the line side of the breaker.

Switch-Onto-Fault Logic provides instantaneous non-directional overcurrent tripping for circuit breaker when a circuit is energized. The logic provides a programmable time window for the Switch-Onto-Fault element to trip immediately after the circuit breaker closed.

7. Out-of-Step Protection

Out-of-Step, loss of synchronism, and pole slipping are synonymous and can result from transients, dynamic instability, or loss of excitation on a generator unit. Detailed stability studies are required to determine if out-of-step protection is required, and the appropriate location for out-of-step protective devices.

Out-of-step relays are sometimes used in the following applications associated with transmission line protection:

- Block Automatic Reclosing - The use of out-of-step relays to block automatic reclosing in the event tripping is caused by instability.
- Block Tripping - The use of out-of-step relays to block tripping of phase distance relays during power swings.
- Pre-selected Permissive Tripping - The use of out-of-step relays to block tripping at selected locations and permit tripping at others during unstable conditions so that load and generation in each of the separated systems will be in balance.

These applications require detailed system studies and are coordinated between system planning, control and protection, and system operations. All use of out-of-step relays in any transmission line application are reviewed by the LIPA T&D Planning Committee.

8. Three Terminal Lines

Three terminal lines are difficult to protect, especially with one or more weak-feed terminals (limited fault current), where high speed reclosing is required, and where an electromechanical relay scheme is used. Standard backup or permissive trip protection on LIPA transmission lines use phase distance relays for phase fault protection and a combination of ground distance and directional ground overcurrent relays for ground fault protection. Relay sensitivities for line faults are affected by current distribution and bus voltage reductions. The apparent reach of the distance relay is a function of fault location, and voltage and current distribution. The zone 1 instantaneous setting of each of the three distance relays usually must be significantly reduced to prevent over tripping beyond the nearest of the two terminals. The zone 2 and 3 reaches must like wise be significantly increased to reach beyond the farthest line terminal, with increased time delays to coordinate with remote relays. A similar situation exists with the directional ground overcurrent relays. Current differential or permissive transfer trip relay schemes could be used but protection would be totally dependent on the availability and dependability of multiple pilot channels. For these reasons, new construction of three terminal lines is generally not permitted on the LIPA system. If new construction of three terminal lines is accepted, then 2nd contingency planning criteria will be applied for the lines and substations involved and redundant communications and protection equipment will be required.

9. Automatic Reclosing of Transmission Lines

On the transmission system, reclosing is not allowed when the circuit is 100% underground cable. On overhead transmission circuits, one-shot time delayed reclosing is permitted. Circuits that are both overhead and underground will be considered on a case-by-case basis. Prior to installing reclosing on breakers close to generating stations a system study is required.

H. SUBSTATION TRANSFORMER PROTECTION

1. Multiple Breaker Station

Primary protection shall consist of current differential relays and a Bucholtz relay. Back-up protection shall consist of phase overcurrent relays with time delayed and instantaneous elements. The transformer high side leads shall be protected by the high side bus current differential relays.

The circuit switcher will clear transformer and low side incoming faults if the fault current is within its interrupting capability. If not, all high side line breakers will be tripped. If there is a bus tie breaker, only the breakers on the transformer side of the bus tie breaker and the bus tie breaker will be tripped.

2. Ring Bus Configuration

In a ring bus, primary protection shall consist of current differential relays and an approved sudden pressure relay. Back-up protection shall consist of phase overcurrent relays with time delayed and instantaneous elements.

The primary zone of protection covers the transformer and transformer high and low side leads. The high side current sensing transformers are located on both breakers in the ring bus supplying the transformer and the low side current transformers are located on the 13 kV bus side of the switchgear incoming breaker.

3. Ground Switches

For 69 kV and below, when a direct trip via fiber optic channel is not available, ground switches may be used to clear transformer faults undetected by remote substation breakers when there is only one fault-interrupting device (circuit breaker/circuit switcher) between the transformer and the transmission line.

I. Other Substation Equipment Protection

1. Bus Protection

Primary current differential protection with fault detection is employed for bus protection.

2. Shunt Reactor Protection with Isolating Device

A current differential protection system and an approved sudden pressure relay will provide primary protection. An overcurrent protection system on separate current transformers will provide back-up protection. Primary and back-up relays trip the reactor breaker and initiate breaker failure.

If the reactor is on the line side of the transmission line breaker, the primary and back-up relays as well as tripping the reactor breaker will initiate breaker failure for the local line breaker, direct transfer trip the remote line breaker in the event the reactor breaker does not trip. It will also operate the reactor ground switch, which will only be effective if the local and remote breakers do not trip. If a fiber optic communication channel is available, the ground switch will not be installed.

3. Shunt Capacitor Protection

Phase and ground relays with time delay and instantaneous elements are employed. A voltage imbalance scheme to prevent imposing greater than 110% rated voltages on capacitor cans in the event of multiple blown fuses. Protection of the capacitor bank breaker is included in the substation bus current differential scheme.

4. Phase Angle Regulator Protection

A primary current differential system, which includes the series and exciting windings using dedicated current transformers, will be employed. Overcurrent relays will be installed in the neutrals of the exciter and regulating windings when they exist. An overcurrent relay system will be used to detect out-of-step tap changer positions. Bucholtz relays (one per tank) will be used to trip the unit.

In units with a series and exciting winding where the exciting winding is connected delta, a primary current differential system that includes the series and excited windings using dedicated current transformers is used.

A back-up current differential system that includes the series and exciting windings on dedicated current transformers is used. A current differential system within the exciting winding delta on dedicated current transformers is used.
Back-up overcurrent relays on each phase inside the delta of the exciting winding on dedicated current transformers are used.

5. Breaker Failure Protection

Where 9-cycle breaker failure tripping is required (on 138 kV and above), the primary and backup relays initiate a breaker failure sequence by energizing the relay, which allows 5 cycles for the faults to be cleared. If the relays get indication that the breaker has not cleared the fault within 5 cycles of the start of the fault, it assumes the breaker has failed and operates other breakers, isolating the portion of bus with the failed breaker and clearing the fault within 9 cycles of the start of the fault. Where slower breaker failure times are permissible, the breaker failure clearing times may be increased.

J. Switchgear Protection

The Switchgear protection system consists of:

- Feeder protection
- Bus protection
- Transformer protection

Each element, feeder, bus and transformer has primary and back-up protective systems.

1. Feeder

The feeder primary protection consists of a microprocessor type relay connected to CTs on the bus side of the feeder breaker. The relay has phase and ground time overcurrent, instantaneous, negative sequence, re-close, sequence of events and oscillography functions all of which are used.

The feeder back-up protection consists of a microprocessor type double element relay, each element of which is connected to its own CTs on the line side of the feeder breaker. This relay is shared by 2 feeders, one element per feeder. Each element has phase and ground time overcurrent functions. For circuit protection outside the substation, reference DA-55-204 is followed.

2. 13 kV Bus

The 13 kV bus primary protection consists of a full bus differential relay, which is connected to the Switchgear incoming breaker CTs on the transformer side of the breaker, to the bus tie breaker CTs on the 2nd bus side and to CTs on the line side of each of the feeder breakers.

The 13 kV bus back-up protection consists of a semi bus differential relay, which is set to coordinate with the feeder relays. It backs up the feeder relays as well as the full bus differential. This relay is connected to the same CTs as the full bus differential relay.

3. Two 13 kV Bus-Tie Breakers

Where there are two 13 kV bus tie breakers, an overcurrent relay is used as a bus differential relay. The relay is connected to the breaker CTs on the bus 1 and 2 sides of the breakers. This will trip both breakers for a fault within its zone of protection and start breaker failure for a failure of either bus tie breaker.

4. Step-down Transformer

The transformer primary protection consists of a transformer differential relay with harmonic restraint. The transformer Bucholtz relay is also considered primary relaying and operates the same lockout relay as the differential relay. The differential relay is connected to CTs on the high side of the transformer and to CTs on the bus side of the Switchgear incoming breaker. If the transformer has a high side breaker, the differential relay is connected to the breaker CTs. The breaker is then included in the transformer primary zone of protection.

The transformer back-up protection consists of three phase time and instantaneous overcurrent relays, which are connected to CTs on the high side of the transformer. In most cases they are connected to the same set of CTs as the differential relay. These relays are set to coordinate with the 13 kV semi bus differential relay. Another time overcurrent relay is connected to the transformer secondary winding neutral CT. This relay acts as a back up to the transformer relaying and also backs up the semi bus differential relays. It is especially useful for fast clearing of ground faults between the incoming breaker and the Switchgear bus.

In a ring bus station, the transformer differential and backup relays are connected to the transformer high side CTs. Additional bus differential relays will overlap on the transformer high side CTs and connect to each of the ring bus breaker CTs. This separate differential relay system will differentiate between a ring bus fault and a transformer fault and allow rapid restoration of the ring bus via supervisory when the transformer is faulted.

K. REDUNDANCY CRITERIA

Current transformers and potential transformers do not normally require redundancy, as failures of these devices are rare and the loss of one CT or PT will not prevent the detection of phase-to-phase or 3 phase faults.

The 125 volt D.C. battery system used for control, tripping, and auxiliary relay operation usually does not require a second back-up battery as the battery voltage itself is constantly monitored and will alarm well before any circuit breaker or major component becomes inoperable. Where a second D.C. supply is required to assure fast clearing back-up protection for various faults to maintain system stability, a back-up battery and charger (operated in parallel with the main battery) are installed.

Where end zone fault clearing times are required to be less than 15 cycles to maintain stability, dual primary relaying is used. The two independent primary relaying systems have separate current transformers. With dual primary relaying on 138 kV or 345 kV circuits, four-cycle clearing for three-phase or line to ground faults on 100% of the circuit is maintained for all faults.

L. Communication Channels

Dedicated fiber is the preferred communication channel for relaying. Most fiber cable on the LIPA system is under built on the transmission and distribution systems. Fibers associated with the multiplexed system are also under-built on the transmission and distribution systems with various levels of redundancy depending on the configuration. Fibers built on the distribution system have routing completely independent of the transmission system. Broken transmission conductors are not common but if a conductor breaks it could disable the pilot channel. In the case of a broken fiber on the multiplex system a redundant path is available.

A fiber optic pilot channel is always preferable to copper wire as it is not susceptible to ground potential rise (GPR) during fault conditions. Copper pilot channels are susceptible to GPR and frequently malfunction during fault conditions when it is essential to operation of the primary relay system.
Use of microwave communication channels is limited mainly because of capital and high maintenance costs.

Power line carrier is sometimes used as an additional communication channel when redundant relaying with an alternate communication path is needed.

The predominant communication channels on the LIPA system are leased telephone lines. These are mostly four-wire audio grade and some single pair lines with limited series loop resistance and total shunt capacitance (wire-to-wire capacitance). The Telephone Company is phasing out the latter type. Telephone lease lines are susceptible to GPR and do not always function when required which is why dedicated fiber and fiber multiplexing is used wherever possible.

X. Equipment Rating Criteria

This section describes the criteria used in rating overhead and underground conductors, substation bus sections, power transformers, circuit breakers, disconnect switches, current transformers and wave traps.

A. OVERHEAD LINE CONDUCTORS

The prime consideration in thermal rating determination is that the conductor does not sustain more loss of strength due to annealing over its useful life. Allowable conductor temperatures for each operating condition are determined on the basis of the loss-of-strength criteria[30] and the assumed number of hours of operation at each condition.

Overhead conductor ratings are determined based on recommended conductor operating temperatures as they relate to loss of strength, annealing and clearances by calculations based on the conductor temperatures and other parameters with the most important ones being AC resistance, wind speed, wind direction, and ambient air temperature. Rating calculation methods for steady state conditions (normal and LTE) and transient thermal ratings are contained in *IEEE Standard 738 (latest version) for Calculating Current-Temperature Relationship of Bare Overhead Conductors and the 1995 Final Report on Tie-Line Ratings from the New York Power Pool (NYPP) Tie-Line Task Force*. LIPA ratings are calculated in accordance with these documents which are also followed by NYISO.

In general, overhead conductors are temperature rated as follows:

Table 5 Overhead Conductors -- Temperature Ratings

	SUMMER RATING (AMBIENT 35°C) WINTER RATING (AMBIENT 10°C)		
CONDUCTOR TYPE	**CONDUCTOR MAXIMUM TEMPERATURE**		
	NORMAL	**LTE**	**STE**
COPPER	80 °C	105 °C	105 °C
ALUMINUM	85 °C	95 °C	105 °C
ACSR	95 °C	115 °C	125 °C
ACAR	95 °C	110 °C	120 °C
SSAC	200 °C	200 °C	200 °C

Overhead conductors operating at 138 kV are typically installed within open right-of-ways and are rated at a wind speed of three (3) feet per second in accordance with the standards referenced above. Overhead conductors operating at voltages less than 138 kV are typically installed along "franchised" routes and are rated at a wind speed of two (2) feet per second. These criteria are based upon variables such as the:

- Line route and line spans
- Pole heights and municipal pole height restrictions
- Obstructions that minimize wind effects
- Wind direction

The ampacities for two (2) feet per second operation are summarized in LIPA's Design and Applications Standard DA-10001 – "Current Carrying Capacity Tables".

[30] Usually 10%. Refer to NYPP Final Report on Tie-Line Ratings - 1995

Through the design process, overhead conductors will meet or exceed the clearance requirements of ANSI C2 –“National Electrical Safety Code” and are not sag limited when operated in conjunction with the temperature ratings described above.

A study of LIPA system wide weather conditions (wind speeds, direction, solar radiation, and temperature) affecting overhead transmission lines has been completed and is currently under review for integration into LIPA’s overhead transmission ratings methodology.

B. UNDERGROUND CABLES

Underground transmission cable ratings are based upon a series of parameters that are unique to the planned cable installation. Such parameters are:

- Cable type (solid dielectric, gas filled, fluid filled, etc.)
- Thermal resistivity of the soil surrounding the cable
- Depth of burial and layout of cable in the trench
- Allowable normal and emergency cable operating temperatures
- Duct or ductless installation
- Loss factor and load factor

Each type of cable has varying operating temperatures. Rating calculations consider all of the above parameters to develop ampacity values for the cable using analytical techniques by Neher-McGrath: "*The Calculation of the Temperature Rise and Load Capability of Cable Systems*", industry standards such as

- *IEC 60-287: "Calculation of Continuous Current Rating of Cables"*
- *IEC 60-853: "Calculation of the Cyclic and Emergency Current Rating of Cables*".

and the following computer based software programs to calculate ampacity ratings based on specific project information such as cable type, soil, depth of installation, etc.

- CYMECAP^{TM} a product of CYME International
- USAMP Plus^{TM} a product of Underground Systems Incorporated

Selection of cable types is primarily based upon electrical requirements such as ampacity, impedance, short circuit capability, and charging current as well as environmental considerations.

The LIPA transmission system has solid dielectric, gas filled and fluid filled (pipe type and self contained) underground cables. Various techniques are utilized to reduce “hot spots” in fluid filled cables such as fluid shuttling, circulation and rapid circulation. Circuit ratings are influenced by each of these techniques.

Solid dielectric cable is being utilized by LIPA in most new installations because of its low maintenance cost and environmentally friendly operation when compared to the traditional fluid or gas filled cables.

C. AERIAL CABLES

The LIPA transmission system also has cables that are installed above ground on poles called “aerial” cables. Aerial cable ratings are based on the following parameters:

- Line route
- Cable type (solid dielectric, gas filled)
- Allowable normal and emergency cable operating temperatures
- Ambient weather conditions
- Loss factor and load factor

Aerial cable ratings are obtained utilizing the software packages mentioned in Section B above

D. SUBSTATION BUS SECTIONS

Substation bus sections are either rigid bus or wire type bus called "strain" bus. The ampacity requirements for bus conductors are usually determined by the full-load ratings of the attached equipment or transmission lines. Temperature limitation of the connected equipment may be a factor in determining conductor loading limits when operation of conductors at excessive temperatures may cause damage to the connected equipment by heat transfer.

The predominant size of aluminum rigid bus on the LIPA system is four (4) inches in diameter. Smaller sizes are used where increased future capacity requirements are not envisioned resulting in considerable construction cost savings. Strain bus can utilize a variety of wire types and sizes to suit the necessary power flow requirements.

Bus conductor ampacity limits are affected by conductor size, material, wind velocity, ambient temperature, convective heat loss, radiation heat loss and solar heat gain. Ampacity rating factors for rigid bus conductors are based on information given in the latest version of the "*IEEE Guide for Design of Rigid Bus Structures Std. 605" (latest version).* Ampacity rating factors for bare wire bus conductors are evaluated for maximum loadings for steady state and contingency conditions using the rating factors used for transmission line conductors, except that for substation bus conductor ampacity calculations, a wind velocity to two feet per second (fps) is utilized.

E. POWER TRANSFORMERS

1. Step-down Transformers

a. Transformers rated 100 MVA and higher

Normal Loading Criteria – Step-down banks normal loading shall not exceed the ratings based on ANSI Standards for hot spot and top oil temperatures as detailed in the latest version of the *"IEEE Guide for Loading Mineral Oil Immersed Transformers C57.91"*.. Manufacturers test data shall be used in conjunction with an assumed 24 hour flat load cycle preloading of 90 percent of nameplate for all similar transformers on the system [31]. The summer and winter Normal (N), Long Term Emergency (LTE), and Short Term Emergency (STE) ratings are to be calculated through use of the EPRI PTLOAD (or similar) computer program. Each transformer shall be evaluated on a case by case basis, taking into account specific nameplate data and system location. Maximum loading shall not exceed 150% of nameplate rating.

A transformer's ratings shall also reflect selected values for the loss of the transformer's life which will be caused by its operation at the criteria temperatures, for a specified duration.

1. *Normal rating* based on 0.0133% loss of life.
2. *Long Term Emergency (LTE) and Short Term Emergency (STE)* ratings based on 0.25% loss of life.

Contingency Loading Criteria - For loss of a step-down bank, the remaining step-down banks shall supply the system load within normal loading and voltage ratings without

[31] Exceptions to the 90% preloading level may be necessary depending upon the specific transformer application (i.e. HVDC tie line transformer, PAR). Prudent engineering judgment shall be used.

exceeding the remaining bank's long term emergency (LTE) rating. The relatively conservative ratings of step-down banks (flat load cycle) assures that the remaining step-downs can carry the load for the extended period required to replace the failed unit.

Power transformers that are specified for use on the LIPA system are equipped with bushings and load tap changers having continuous thermal ratings greater than or equal to that of the transformer at nameplate rating. As a result, the transformer bushings or the load tap changers are not thermal limiting elements.

b. Transformers rated less than100 MVA

Normal Loading Criteria – Step-down banks normal loading shall not exceed the ratings based on ANSI Standards for hot spot and top oil temperatures as detailed in the latest version of *"IEEE Guide for Loading Mineral Oil Immersed Transformers C57.91"*. Manufacturers test data shall be used in conjunction with a 24 hour load cycle based on actual loading experience during peak load periods. The summer and winter Normal (N), Long Term Emergency (LTE), and Short Term Emergency (STE) ratings are to be calculated through use of the EPRI PTLOAD (or similar) computer program. Each transformer shall be evaluated on a case by case basis, taking into account specific nameplate data and system location. Maximum loading shall not exceed 150% of nameplate rating.

A transformer's ratings shall also reflect selected values for the loss of the transformer's life which will be caused by its operation at the criteria temperatures, for a specified duration.

1. *Normal rating* based on 0.0133% loss of life.
2. *Long Term Emergency (LTE) and Short Term Emergency (STE)* ratings based on 0.25% loss of life.

Contingency Loading Criteria - For loss of a step-down, the remaining step-downs shall supply the system load within normal loading and voltage ratings without exceeding the remaining banks' long term emergency (LTE) rating.

Power transformers that are specified for use on the LIPA system are equipped with bushings and load tap changers having continuous thermal ratings greater than that of the transformer at nameplate rating. As a result, the transformer bushings or the load tap changers are not thermal limiting elements.

2. Distribution Substation Transformers

Distribution Substation Transformers are rated by a computer program that uses the basic equations from the American Standards National Institute (ANSI) standards for maximum internal hot spot and top oil temperatures as detailed in the latest version of the *IEEE Guide for Loading Mineral-Oil-Immersed Transformers (IEEE C57.91- latest version) and "The New York Power Pool Task Force on Tie Line Ratings Report" - Final Report 1995".* The manufacturer's factory test data and the experienced 24-hour loading curve data are utilized in an iterative computer program that calculates allowable loading levels. The transformer's ratings for *the Normal (N), Long Term Emergency (LTE)*, and *Short Term Emergency (STE)* load levels are identified based upon maximum internal temperatures and selected values for the loss of the transformer's life which will be caused by its operation at the criteria temperatures, for a specified duration, on a defined load curve.

1 *Normal rating* based on 0.20% loss of life per year.

2 *Long Term Emergency (LTE) rating* (more than one hour), associated with 3.0% loss of life or Top Oil temperature not to exceed 130°C or Hot Spot

conductor temperature not to exceed 180°C. These temperature limits are for 65°C rise transformers. For 55°C rise transformers the values are 100°C Top Oil and 150°C Hot Spot.

3 *Short Time Emergency (STE) rating (less than one hour).* Associated with 3% loss of life, or hot spot conductor temperature not to exceed 180°C for 65°C-rise transformer (150°C for 55°C-rise transformer).

4 *Maximum load* for ½ hour or more is 200% of nameplate value.

F. CIRCUIT BREAKERS

The rating factors for circuit breakers are based on the latest versions of ANSI standard C37.06-2000 'AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis - Preferred Ratings and Related Capabilities' and *ANSI standard C37.010 'Application Guide for AC High Voltage Circuit Breakers Rated on a Symmetrical Current Basis',* which respectively cover the preferred ratings for circuit breakers and the continuous, LTE and STE conditions. Continuous-current temperature limits of breaker components are not exceeded during normal loading. During LTE and STE loading, breaker component temperatures up to 15°C above the continuous-current limits are allowed. Some loss of life may result.

Circuit breaker bushings specified for use on the LIPA system are typically rated for continuous operation to match the nameplate rating of the breaker. As a result the bushings are not the thermally limiting element of the circuit breaker.

1. Rating Factors for LTE Conditions

Rating factors for LTE conditions are based on ANSI C37.010 as well. Emergency load-carrying ability is achieved in the application guide by increasing the allowable total temperature and temperature rise of breaker components above the values allowed for continuous operation. The guide states that this may reduce operating life of the breaker. Conditions for using the LTE emergency rating factors are found in section 5.4.4 "Emergency load current carrying capability" of ANSI C37.010 and include the following:

1. Application is to outdoor breakers only (metal-clad switchgear will have its own application guide).
2. The circuit breaker shall have been maintained in essentially new condition.
3. For a minimum of 2 hours following the emergency period, load current shall be limited to 95% of the rated continuous current for the selected ambient temperature (normal rating).
4. Mandatory inspection and maintenance procedures found within the ANSI Standard and recommendations by manufacturers are required to be followed after emergency operation.
5. During and after emergency operation and prior to maintenance, the circuit breaker shall be capable of one operation at its rated short-circuit current.

The guide provides rating factors for four-hour and eight-hour periods of emergency operation. The factors are based on increased operating temperatures of 15°C for four hours and 10°C for eight hours, above the temperature limits for continuous operation. The four-hour and eight-hour periods must be separate. Inspection and maintenance efforts are required when the duration of separate periods of emergency operation totals 16 hours.

2. Rating Factors for STE Conditions

The same 15°C increase is allowed in the total temperature of circuit breaker components as for the four-hour emergency rating. Conditions for using the STE emergency rating factors are found in section 5.4.4 "Emergency load current carrying capability" of ANSI C37.010 and are the following:

1. Initial current shall not be greater than the normal rating at actual ambient temperature.
2. Following application of a short-time emergency current, current must be reduced to a level not exceeding the four-hour emergency current (LTE rating) for the remainder of the four-hour period, or to not more than 95% of the rated continuous current (Normal rating) for a minimum of two hours.
3. Regarding inspection and maintenance requirements, each isolated short-time emergency event shall be considered equal to one four-hour emergency period unless it is part of a four-hour emergency period.

The duration of the short time emergency load current shall be limited to a time that will not result in a breaker component exceeding the limits of total temperature specified in the latest version of IEEE Standard/ANSI C37.04 – "IEEE Standard Rating Structure for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis" by more than 15°C.

In summary, the following rating factors should be used for circuit breakers:

Table 6 Circuit Breakers -- Rating Factors

CIRCUIT BREAKERS	SUMMER			WINTER		
	NORMAL	LTE	STE	NORMAL	LTE	STE
	104%	116%	133%	122%	134%	149%

Note: Percentages are based upon nameplate rating (100% = nameplate)

G. Disconnect Switches

The standard requirements for high voltage air-disconnect switches are covered in the latest versions of *IEEE/ANSI Standards C37.30 to C37.37* related to high voltage switches. These standards specify, in addition to other requirements, the rated current, the conditions under which the rated current is determined and the maximum allowable temperature rise limitations of the various components in the switch. For example, the maximum temperature rise for silver-to-silver contact in air is 53°C. A formula is provided in the latest version of *IEEE/ANSI Standard C37.30 "IEEE Standard Requirements for High Voltage Switches"* for the calculation of the allowable continuous current at ambient temperature at which the switch can operate without exceeding its temperature rise limitation.

Prior to 1971, IEEE/ANSI Standards allowed a 30°C temperature rise over a maximum ambient of 40°C, for a maximum overall temperature of 70°C. Switches manufactured in accordance with the 30°C temperature rise limit have a higher loading capability than switches manufactured in accordance with standards published in 1971 and later.

Table 7 Disconnect Switches -- Ratings

AIR DISCONNECT SWITCHES	SUMMER			WINTER		
	NORMAL	LTE	STE	NORMAL	LTE	STE
30° C Temperature Rise - Pre 1971	108%	153%	200%	141%	178%	200%
53° C Temperature Rise - 1971 and later	105%	127%	160%	125%	144%	174%

Note: Percentages are based upon nameplate rating (100% = nameplate)

Two switch ratings are listed in the above table. The ratings listed under 30°C rise apply to those switches designed in accordance with the 30°C rise limitation (prior to 1971). The ratings listed under 53 ° C rises apply to those switches with silver-to-silver contacts designed in accordance with standards published in 1971 and later. LIPA follows the above table and rates switches accordingly depending on the year of manufacture.

H. Current Transformers

Thermal ratings of current transformers will require a review of each application and the manufacturer's practice. *A single set of rating factors can not be expected to cover the variety of installations that are possible*. Thermal overload of devices in the secondary circuit must be considered. A careful review of the application is mandatory for any current transformer that is the limiting component in rating a transmission facility

The methods of rating current transformers are based on the latest versions of ANSI/IEEE Standards, including *ANSI/IEEE C57.13, ANSI Standards C57.91 and C57.92)*.

1. Free Standing Current Transformers

Table 8 Free Standing Current Transformers -- Rating Factors

CURRENT TRANSFORMERS	SUMMER			WINTER		
	NORMAL	LTE	STE	NORMAL	LTE	STE
Free Standing Types	100%	128%	150%	122%	148%	150%

Note: Percentages are based upon nameplate rating (100% = nameplate)

The LTE and STE rating factors in the above table are for oil filled units installed separately from other equipment. Since these units are similar in construction to power transformers, the equations for transient heating that are found in *Section 6.7 of Standard C57.92* were used to develop LTE and STE ratings.

For new construction, free standing current transformers are typically sized to coincide with the substation bus ampacity requirements.

Parameter value and the calculations are the same as for power transformers in this report, assuming at 55°C average winding rise in accordance with the limit given in C57.13 for instrument transformers. With no requirements stated in C57.13, current and power transformers were assumed to have the same parameter values for hottest-spot temperature related to loss of life and ratio of load to no-load loss. Thermal time constant was assumed equal to that of a forced air coiled power transformer.

2. Bushing-Type Current Transformers

The LTE and STE ratings of bushing-type current transformers will normally be at least as great as the rating of the circuit breaker or power transformer in which the CTs are installed. The manufacturer of the major equipment can provide CTs with thermal performance that is adequate, taking into account the ambient temperature at which they will operate in or on the equipment and other factors. Confirmation of the LTE and STE ratings should be sought from the equipment manufacturer.

I. POTENTIAL TRANSFORMERS

Potential transformers for protective relaying are rated in accordance with the latest version of *ANSI/IEEE Standard C57.13 "Standard Requirements for Instrument Transformers"*. The ratings are expressed in terms of primary voltage, frequency, accuracy class, thermal burden and basic impulse insulation level required by the system on which they are being applied. Two nominal secondary voltages (115 and 120V) are allowed. Most protective relays have standard voltage ratings of 120 or 69 volts depending on whether they are to be connected line– to–line or line–to-ground. ANSI accuracy class 0.3 (See C57.13, Table 6) and thermal burden ZZ (See C57.13, Table 15) is specified for the LIPA system.

J. WAVE TRAPS

Wave or Line traps consist of a parallel tuned resonant circuit that presents high impedance to the operating carrier frequency but negligible impedance at system frequency. A line trap usually consists of an air-core inductance coil in series with a power line conductor and tuned to parallel resonance by means of a tuning pack. In 1981 ANSI published a new standard for line traps to replace an old NEMA Standard. This ANSI Standard has titled *"Requirement for Power Line Carrier Line Traps" ANSI C93.3-1981*. The following statement is extracted from the 1981 Standard:

> "*Line traps are designed within temperature rise limitations to ensure normal life expectancy. Any value of current in excess of the rated current in this standard may cause the designed temperature rise to be exceeded and may shorten the life expectancy of the line trap. Table A-1, however, shows percentages of rated continuous current that have been selected to minimize the reduction in operating life and should be applied with great care".*

(During the 1994 review of the *"Final Report New York Power Pool Task Force on Tie Line Ratings, June, 1982'*", it was discovered that the proposed standards for line traps had been withdrawn and consequently there was no formal standard for this piece of equipment. However, since a letter from Trench Electric (date unknown), confirms some Table A-1 entries of the 1982 NYPP Report and refutes none, the 1995 New York Power Pool Task Force on Tie Line Ratings recommended using the ratings developed by the 1982 Task Force on Tie Line Ratings)[1]. They are:

[1] Excerpt form Page 81 of the "Final Report New York Power Pool Task force on Tie Line Ratings –1995"

Table 9 Wavetraps -- Rating Factors

WAVETRAPS	SUMMER			WINTER		
	NORMAL	LTE	STE	NORMAL	LTE	STE
	101%	111%	141%	107%	118%	150%

Note: Percentages are based upon nameplate rating (100% = nameplate)

K. Series Reactors

Series reactors are occasionally used on the transmission system to either limit short circuit current, or to reduce the thermal loading on transmission lines. The standard covering the use of series reactors is ANSI C57.99-1965, Guide for Loading Dry-Type and Oil-Immersed Current-Limiting Reactors. The guide provides general recommendations for loading both Dry-Type and Oil-Immersed current limiting reactors. The following rating guide indicates the "Daily Peak Loads Above Name Plate Rating to Give Normal Life Expectancy in 30 C Average Ambient for Dry-Type 55^{o}C or 80^{o}C Rise Self-Cooled":

Table 10 Dry-Type 55^{o}C or 80^{o}C Rise Self-Cooled Series Reactors

Peak Load Time in Hours	Time Rated Amperes Dry-Type 55^{o}C or 80^{o}C Rise Self-Cooled(AA) Following and Followed by a Constant Load of		
	90 Percent	70 Percent	50 Percent
½	1.21	1.51	1.70
4	1.00	1.01	1.03

The Final Report of the New York Power Pool Task Force On Tie Line Ratings, November 1995 extended the above ratings to be applied to summer and winter Normal, LTE & STE ratings as follows:

Table 11 Dry-Type 55^{0}C or 80^{o}C Rise Self -cooled Series Reactors

Season	SUMMER				WINTER			
Operating Conditions	Ambient	Normal	LTE 4 hours	STE 30 min.	Ambient	Normal	LTE 4 hours	STE 30 min.
55^{o}C Rise Dry-Type self-cooled * Following and Followed by a Constant Load of 90 percent	35^{o}C	96%	96%	116%	10^{o}C	114%	114%	140%
	30^{o}C	100%	100%	121%	5^{o}C	118%	118%	142%
	25^{o}C	104%	104%	125%	0^{o}C	121%	121%	146%
80^{o}C Rise Dry-Type self-cooled * Following and Followed by a Constant Load of 90 percent	35^{o}C	98%	98%	118%	10^{o}C	109%	109%	132%
	30^{o}C	100%	100%	121%	5^{o}C	111%	111%	136%
	25^{o}C	102%	102%	124%	0^{o}C	114%	114%	137%

Note 1: The shaded area numbers are taken from the ANSI guide. Other numbers are calculated.
Note 2: The following factors from the ANSI guide are used for the calculations:
For 55^{o}C Rise Dry-Type: 0.85% decrease for each degree C temperature above 30^{o}C
0.70% increase for each degree C temperature below 30^{o}C
For 80^{o}C Rise Dry-Type: 0.50% decrease for each degree C temperature above 30^{o}C
0.45% increase for each degree C temperature below 30^{o}C

XI. COMPUTER MODELING TOOLS

A series of computer modeling programs are utilized in the electric system planning process. General Electric's MAPS™ and MARS™ are utilized among others for generation planning while Siemens Power Technologies' PSS/E™ and General Electric's PSLF™ are used in planning the transmission system. The ASPEN™ modeling program is utilized for short circuit analysis on the transmission system and CYMDIST™ is used to help analyze radial feeders and networks on the distribution system.

EPRI model PTLOAD™ is used to evaluate ratings for transformers less than 100MVA.

SUBREL™ is utilized to evaluate substation reliability and EPRI's PRA software is used to analyze risk on the transmission system be measuring the probability and impact a system event can cause.

Since these programs are widely used throughout the industry it becomes relatively simple to exchange technical data with other utilities when there is a need to model other electric systems in LIPA's internal studies.

The following table summarizes the major models used to support and enhance the planning effort.

Table 12 Major Planning Tools / Models

MODEL	DESCRIPTION	PURPOSE
MAPS™	General Electric's Multi-Area Production Simulation™ (MAPS™); transmission constrained generation dispatch model	Energy costs/pricing
MARS™	General Electric's Multi-Area Reliability Simulation™ (MARS™); probabilistic assessment of area power system reliability	Loss of Load Expectation (LOLE)
Strategist™	New Energy Associates' Strategist™ generation dispatch model and supply side optimization of resource choices.	Resource optimization; energy cost/revenue/dispatch
PSS™/E	Siemens Power Technologies International's Power System Simulator™/Electric System; transmission system load flow model	Transmission system load flow; thermal, voltage, and dynamic fault analyses under normal and contingency conditions
PSLF™	General Electric's Power System Load Flow™ (PSLF™); Transmission system load flow model	Transmission system load flow; thermal, voltage, and dynamic fault analyses under normal and contingency conditions
ASPEN™	Advanced Systems for Power Engineering, Inc Short circuit analysis program	Breaker fault duty analyses on the Transmission system.
CYMDIST™	Cognicase-Cyme Inc., CYMDIST™ Distribution Primary Analysis; analysis of radial and network distribution systems	Thermal, voltage, and contingency analyses of distribution feeders and networks.
PRA™	EPRI's Probabilistic Risk Assessment (PRA™) program to analyze risk of the power system.	Used in conjunction with load flow program (PSS/E™), determines likelihood and severity of system events occurring and compiles results into deterministic and probabilistic indices.
PTLOAD™	EPRI program to evaluate transformer loading	Computes rrating for transformers less than 100MVA
SUBREL™	General Reliability's computer program for substation reliability evaluation	Computes reliability indices for different substation bus configurations

XII. Major Electric System Studies

The following is a list of the main transmission and distribution planning studies performed to ensure that the LIPA T&D system continues to adhere to the planning criteria discussed in this document. A nominal schedule for performing these studies is also shown, but it should be noted that the indicated study may be performed at a different frequency if system changes dictate. It is recognized that additional targeted studies are routinely performed to review the adequacy of the system which may supplant this study listing.

In addition, when a significant event occurs, LIPA will perform a Significant System Event Investigation (SSEI) and issue a report on its findings. A guideline, GO-10423 outlines the process.

Table 13 Recurring Planning Studies

STUDY TITLE	OBJECTIVE	NOMINAL FREQUENCY
Summer Peak Load Forecast (20 Years)	Develop peak load forecast for NYISO installed capacity requirements, other regulatory filings and Resource Planning Coordinating Committee	Annually, Fall
Forecasted Load Duration Curves under Normal and Extreme Weather (3 years)	Develop for Summer Operating study	Annually, Spring
NYISO Operating Study	Identify power transfer limits expected in the NYCA during upcoming peak summer season	Annual. Spring
NYISO Winter Operating Study	Identify power transfer limits expected in the NYCA during upcoming winter peak season	Annual. Fall
Summer Operating Study (minus extreme contingency and voltage assessment analysis)	Identify transmission and distribution system limitations and power import limits expected during upcoming summer peak season	Annual. Spring
Winter Operating Study	Identify transmission and distribution system limitations and power import limits expected during upcoming winter peak season	Evaluate need to conduct study every Fall. Perform study if required.
Extreme Contingency Conditions Analysis (part of summer operating studies)	Analyze transmission system performance during extreme contingencies	Annual. Spring
Long Term Plan (LTP)	Transmission owners provide details of their long term transmission plans including criteria, models, and local area development	Annual, Fall
Short Range (Up to 5 Years) Transmission System Studies	Identify transmission system limitations and recommend reinforcements for an area of the system within a 5 years time frame. Results in development of major Transmission capital projects	When generation additions are identified and/or when load growth demand substation reinforcements in an area of the system
Long Range (5 to 40 Years) Transmission System Study	Identify transmission system architecture in the 35 to 40 year range and identify transmission system limitations and recommend reinforcements that will be required in 5 to 20 years to meet load growth and new generation injections.	Every five years or when generation additions are identified and/or when load growth demand substation reinforcements in an area of the system

STUDY TITLE	OBJECTIVE	NOMINAL FREQUENCY
System Reliability Impact Studies	Determine impact on the LIPA transmission system of proposed new generation or interconnections and recommend reinforcements to the system as required. Could result in development of major Transmission Capital Projects.	As required for new generation or interconnection additions
Short Circuit Study Transmission Breakers	Ensure that there are no overstressed circuit breakers	Every 3-5 years and when studying generation additions and/or major modifications to the transmission system.
Angular Stability Study	Ensure that electric system will meet system stability design criteria.	Every 5 years and when studying generation additions and/or major modifications to the transmission system.
Voltage Recovery Evaluation - impact of load type changes	Verify validity of complex motor modeling	Every 2 years
System Voltage Study	Ensure system voltage design criteria is met	Substation voltages will be analyzed as part of each transmission system study
NYPA Customer Deliverability Study	Assess deliverability of capacity to NYPA customers on Long Island	Annual. Every March (Per contract)
LIPA Electric System Loss Study	Determine the LIPA system energy (MW-HR) and demand (MW) losses by operating season for T&D delivery components	Annual update and periodic major update on need basis
System Reactive Reserves Evaluation	Provide 10 Year system reactive load forecast and evaluate reactive reserve needs on T&D system	Annual
Summer Load Forecast Distribution Substations and Circuits	Develop three (3) Year Summer Peak Load Forecasts for all LIPA and other major customer-owned distribution substations and circuits.	Annual - Spring
Winter Load Forecast Distribution Substations and Circuits	Develop 3 Year Winter Peak Load Forecasts for all LIPA and other major customer-owned distribution substations and circuits.	Annual - Fall
Distribution Load Transfers	Develop distribution load transfers for seasonal operation of distribution system and for the rearrangement of the distribution system based upon planned distribution line projects.	Semi-Annual - Spring and Fall

STUDY TITLE	OBJECTIVE	NOMINAL FREQUENCY
Substation LTE/STE Overload Analysis	Develop contingency load shed plans for substations where forecasted load will exceed emergency ratings of remaining energized substation transformers.	Annual - Spring
Seasonal Bus -Tie Operation Studies	Analysis of whether distribution bus-tie breakers should be operated in Normally Open or Normally Closed position during Summer and Winter load periods.	Semi-Annual - Spring and Fall
First Contingency Study of Substations / Circuits	Study of contingency capability of all distribution substations and circuits to provide assistance / instructions to Operating Depts. during emergency operation of the distribution system for peak summer load periods.	Annual - Spring
Distribution System Area Studies	Study of a Service Area to identify distribution system (substation/circuit) reinforcements required to supply forecasted load growth. Results in the development of major substation capital projects and distribution line projects.	Annual
Distribution Line Programs: 1. Conversion & Reinforcement (C&R) 2. New Substation Exit Cable 3. Capacitors 4. Automatic Sectionalizing Units (ASU) 5. Short Circuit Distribution Breaker Assessment	Develop projects to ensure adequacy of the distribution system to normally supply forecasted load on circuits and substations, to provide capacity during emergency conditions, to provide operational flexibility to transfer load, and to provide a high degree of service reliability to the customer	Annual - Early Spring through Late Winter
Voltage Control Analysis	Review forecasted Summer and Winter distribution circuit conditions and determine maximum allowable voltage reduction permitted on each circuit during Peak Load periods or during system emergencies	Semi-Annual – Spring and Fall
Studies to Support T&D Operating Departments	Analyze and recommend reinforcements for: a. Distribution line projects to supply new or expanding major customers. b. Investigation of high / low voltage complaints. c. Distribution line fault calculations d. Calculate contact making voltage (CMV) resistance and reactance settings for substation transformers.	Annual (As Requested)

STUDY TITLE	OBJECTIVE	NOMINAL FREQUENCY
FERC 715 Submission	Annual requirement for submitting transmission system data and planning criteria to NYISO and FERC	Annual April submission to FERC
IR-3 Gas Burn Local Reliability Rule	Determine limitation on Northport gas burn requirement	Review annually to determine need to update
NYSRC Initiatives (e.g. IRM study)	Support to NYISO	Annual
RNA Study	Support to NYISO	Annual
NYISO Annual Transmission Baseline Assessment (ATBA)	Create a baseline transmission system for meeting reliability needs of transmission district. This configuration is used for cost allocation purposes of generation and merchant transmission interconnection per NYISO OATT Attachment S procedures.	Annual - February
Review and Update of LIPA T&D Criteria Document	Ensure the document reflects the latest changes	Every two years

XIII. APPENDICES

A. APPENDIX 1 – NERC PLANNING STANDARDS

(http://www.nerc.com/page.php?cid=2|20)

B. APPENDIX 2 – NYSRC RELIABILITY RULES FOR PLANNING AND OPERATING THE NEW YORK STATE POWER SYSTEM

(http://www.nysrc.org/NYSRCReliabilityRulesCompianceMonitoring.asp)

C. APPENDIX 3 – NORTHEAST POWER COORDINATING COUNCIL (NPCC) - REGIONAL RELIABILITY REFERENCE DIRECTORIES AND NPCC DOCUMENTS

(http://www.npcc.org/documents/regStandards/Criteria.aspx)

1. *NPCC Document A-1 Criteria for Review and Approval of Documents*
2. *Directory #1 Design and Operation of the Bulk Power System (Replaced NPCC Document A-2 Basic Criteria for Design and Operation of Interconnected Power Systems)*
3. *NPCC Document A-3 Emergency Operation Criteria*
4. *NPCC Document A-4 Maintenance Criteria for Bulk Power System Protection*
5. *Directory #4 Bulk Power System Protection Criteria (Replaced NPCC Document A-5 Bulk Power System Protection)*
6. *NPCC Document A-7 Glossary of Terms*
7. *NPCC Document A-8 NPCC Reliability Compliance and Enforcement Program*
8. *NPCC Document A-10 Classification of Bulk Power System Elements*
9. *NPCC Document A-11 Special Protection System Criteria*

D. APPENDIX 4 - NYISO TRANSMISSION EXPANSION AND INTERCONNECTION MANUAL

http://www.nyiso.com/public/webdocs/documents/manuals/planning/tei_mnl.pdf

E. APPENDIX 5 - NYISO GUIDELINE FOR FAULT CURRENT ASSESSMENT

(http://www.nyiso.com/public/webdocs/services/planning/planning_data_reference_documents/nyiso_guideline_fault_current_assessment_final013003.pdf)

F. APPENDIX 6 –LIPA INTERCONNECTION REQUIREMENTS

1. *Requirements for Generating Facility Interconnection to the LIPA Transmission System*
2. *Bulk Power System Facility and End User Interconnection Requirements to the LIPA Transmission System*
3. *Revenue Metering Requirements for Generating Facilities Interconnecting to the LIPA Transmission System*
4. *Interconnection Requirements for Distributed Generation Greater than 300kVA*
5. *Interconnection Requirements for Distributed Generation Units of 300kVA or less*

G. APPENDIX 7 – LIPA DISTRIBUTION SYSTEM DESIGN AND APPLICATION STANDARDS

H. APPENDIX 8 – CAPITAL BUDGET PLANNING PROCESS

I. APPENDIX 9 – SUMMARY OF APPLICABLE INDUSTRY STANDARDS

1. Control and Protection

(http://ieeexplore.ieee.org/xpl/standards.jsp)

IEEE Standard C37.11 - IEEE standard requirements for electrical control for AC high-voltage circuit breakers rated on a symmetrical current basis

IEEE Standard ANSI/IEEE C37.21 - IEEE standard for control switchboards

ANSI/IEEE Standard C37.90 - IEEE standard for relays and relay systems associated with electric power apparatus

IEEE Standard C37-91 - IEEE guide for protective relay applications to power transformers

ANSI/IEEE Standard C37.93 - IEEE guide for power system protective relay applications of audio tones over telephone channels

IEEE Standard C37.95 - IEEE guide for protective relaying of utility-consumer interconnections

IEEE Standard C37.96 - IEEE guide for AC Motor Protection

ANSI/IEEE Standard C37.97 - IEEE guide for protective relay applications to power system buses

ANSI/IEEE Standard C37.99 - IEEE guide for protection of shunt capacitor banks

ANSI/IEEE Standard C37.101 - IEEE guide For Generator Ground Protection

IEEE Standard C37.102 - IEEE guide for AC generator protection

IEEE Standard C37.104 - IEEE guide for automatic reclosing of line circuit breakers for AC distribution and transmission lines

ANSI/IEEE Standard C37.106 - IEEE guide for abnormal frequency protection for power generating plants

ANSI/IEEE Standard C37.109 - IEEE guide for the protection of shunt reactors

IEEE Standard C37.110 - IEEE guide for the Application of Current Transformers Used for Protective Relaying Purposes

IEEE Standard C37.113 - IEEE guide for protective relay applications to transmission lines

ANSI/IEEE Standard C57.109 - IEEE guide for transformer through-fault-current duration -

ANSI/IEEE Standard 643 - IEEE guide for power-line carrier applications

IEEE Standard 1375 - IEEE guide for the protection of stationary battery systems

NPCC Directories # 1 and 4 (Replaced NPCC documents A-2 & A-5) for applicable substations and equipment.

2. Overhead Line Conductors

IEEE Standard 738 - Standard for Calculating Current-Temperature Relationship of Bare Overhead Conductors -

LIPA DA-10001 – “Current Carrying Capacity Tables”

ANSI C2 – “National Electrical Safety Code”

3. Underground Conductors

(http://www.iec.ch/index.html)

IEC 287 - Calculation of Continuous Current Rating of Cables

IEC 853 - Calculation of the Cyclic and Emergency Current Rating of Cables.

4. Substation Bus Sections

IEEE Standard 605 – IEEE Guide for Design of Rigid Bus Structures

5. Power Transformers

IEEE Standard C57.91 - IEEE Guide for Loading Mineral Oil Immersed Transformers

6. Circuit Breakers

ANSI/ IEEE Standard C37.04 – IEEE Standard Rating Structure for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis

ANSI Standard C37.010 - Application Guide for AC High Voltage Circuit Breakers Rated on a Symmetrical Current Basis

7. Disconnect Switches

ANSI/ IEEE Standard C37.30 - ANSI Standard Definitions and Requirements for High Voltage Air Switches, Insulators and Bus Supports

ANSI/ IEEE Standard C37.32- ANSI Standard Schedules of Preferred Ratings, Manufacturing Specifications, and Application Guide for High-Voltage Air Switches, Bus Supports, and Switch Accessories

ANSI Standard C37.33 - High Voltage Air Switches – Rated Control Voltages and Their Ranges

ANSI Standard C37.34 - Test Code for High-Voltage Air Switches

ANSI/ IEEE Standard C37.35 – IEEE Guide for the Application, Installation, Operation, and Maintenance of High-Voltage Air Disconnecting and Load Interrupter Switches

ANSI Standard C37.37 – Loading Guide for AC High-Voltage Air Switches (in excess of 1000 volts)

8. Current Transformers

ANSI/IEEE Standard C57.13 - IEEE Standard Requirements for Instrument Transformers

IEEE Standard C57.91 - IEEE Guide for Loading Mineral Oil Immersed Transformers

9. Wave Traps

ANSI Standard C93.3 - Requirement for Power Line Carrier Line Traps

XIV. Definitions

481	Cross Sound Cable HVDC Interconnection
AC	Alternating current
AESO	Alberta Electric System Operator (Alberta, Canada)
ANSI	American National Standards Institute
ASPEN™	Advanced Systems for Power Engineering, Inc Short circuit analysis program
ASU	Automatic Sectionalizing Units
ATBA	Annual Transmission Baseline Assessment
BES	Bulk Electrical System (NERC)
BPS	Bulk Power System (NPCC)
BPTF	Bulk Power Transmission Facilities
BTS	Bulk Transmission System (LIPA)
CAIDI	Customer Average Interruption Duration Index
CARIS	Congestion Assessment and Resource Integration Study
Con Edison	Consolidated Edison Company of New York
C&P	Control and Protection
C&R	Conversion & Reinforcement
CKVA	Circuit KVA
CMV	Contact making voltage
CRP	Comprehensive Reliability Plan (NYISO)
CRPP	Comprehensive Reliability Planning Process
CSI	Customer Satisfaction Index
CSC	Cross Sound Cable
CSPP	Comprehensive System Planning Process (NYISO)
CT	Current Transformer
CYMDIST™	Cognicase-Cyme Inc., Distribution Primary Analysis; analysis of radial and network distribution systems

CYMECAP™	CYME computer program (ampere rating)
DMNC	Dependable Maximum Net Capability
DOE	Department of Energy
D-VAR	Dynamic reactive control device
EFOR	Equivalent Forced Outage Rate
EIPP	Eastern Interconnection Phasor Project
EMS	Energy Management System
ESPWG	Electric System Planning Work Group (NYISO)
EPRI	Electric Power Research Institute
FACTS	Flexible AC transmission
FERC	Federal Energy Regulatory Commission
GPR	Ground potential rise
HELM™	Hourly Electric Load Model
HVDC	High Voltage Direct Current
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers, Inc.
IESO	Independent Electricity System Operator (Ontario, Canada)
IPP	Independent Power Producer
ISO	International Organization for Standardization
IT	Telephone Interference
kV	kilovolts or 1,000 volts
kVA	kilovolt ampere
kW	kilowatt or 1,000 watts
LICA	Long Island Control Area
LIPA	Long Island Power Authority
LP	Load Pocket
LTE	Long--Term Emergency rating
LTP	Local Transmission Plan (NYISO)
LTPP	Local Transmission Planning Process (NYISO)

LOLE	Loss of Load Expectation
LVRT	Low Voltage Ride Through
MAIFI	Momentary Average Interruption Frequency Index
MAPP	Mid-Atlantic Area Power Pool
MAPS™	General Electric Multi-Area Production Simulation Software Program
MARS™	General Electric Multi-Area Reliability Simulation Program
MOV	Metal oxide vayristor
MVA	Megavolt ampere or 1,000,000 volt ampere
MVAR	Megavolt ampere reactive or 1,000,000 volt ampere reactive
MW	Megawatt or 1,000,000 watts
ISO-NE	New England Independent System Operator
NEMA	National Electrical Manufacturers Association
Neptune RTS	Neptune Regional Transmission System
NERC	North American Electric Reliability Corporation
NNC	Northport Norwalk Harbor Cable
NPCC	Northeast Power Coordinating Council
NUSCO	Northeast Utilities
NYCA	New York Control Area
NYISO	New York Independent System Operator
NYPA	New York Power Authority
NYPP	New York Power Pool
NYSRC	New York State Reliability Council
OATT	Open Access Transmission Tariff
PAR	Phase angle regulator
PJM	PJM Interconnection (RTO)
PLC	Power Line Carrier
PMN	Phasor Measurement Network
PMU	Phasor Measurement Units

POTT	Permissive overreaching transfer trip
PQ	Power Quality
PRA™	Probabilistic Risk Assessment from EPRI
PSLF™	General Electric's Power System Load Flow, Transmission system load flow model
PSS™/E	Siemens Power Technologies International's Power System Simulator/Electric System; transmission system load flow model
PT	Potential Transformer
PUTT	Permissive under reaching transfer trip
RNA	Reliability Needs Assessment (NYISO)
RPWG	Reactive Power Working Group (NYISO)
RTO	Regional Transmission Organization
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SOAS	System Operations Advisory Subcommittee (NYISO)
SPS	Special Protection System
SSTI	Sub Synchronous Torsional Interaction
SCC	Superconducting cables
SPCC	Spill Prevention Control and Countermeasure Plan
SVC	Dynamic reactive control device
STE	Short-Term Emergency rating
SUBREL™	General Reliability's computer program for substation reliability evaluation
TOV	Temporary Over voltage
TCC	Transmission Congestion Contract
T&D	Transmission and Distribution
TDPCC	T&D Planning Coordinating Committee
THD	Total Harmonic Distortion

TNA	Transient Network Analysis
TPAS	Transmission Planning Advisory Subcommittee (NYISO)
UCAP	Unforced Capacity
UPS	Uninterruptible Power Supply
VAR	Volt-ampere reactive
WECC	Western Electric Coordinating Council
Y-49	East Garden City – Sprain Brook 345 kV Interconnection
Y-50	Shore Road – Dunwoodie 345 kV Interconnection
Zone 1, 2 &3	Relay protection zones