Orange & Rockland

# LONG-RANGE TRANSMISSION PLAN 2011-2020

**Transmission and Substation Engineering Department**

**August 15, 2011**

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# EXECUTIVE SUMMARY

The Long Range Transmission Plan ("Plan") of Orange and Rockland Utilities, Inc. ("Orange and Rockland") is focused on achieving the objective of reliably serving forecasted loads over a 10-year planning horizon under certain conservative assumptions. The Plan both meets this objective and adheres to Orange and Rockland's Transmission Planning Criteria (Appendix A). Although the assumptions were based on the approved 2011-2015 Orange and Rockland Capital Budget, the Plan may change over time in order to adapt to changing future conditions which include: variations in load forecast and load distribution, evolving new generation development projects, merchant transmission projects, demand side management programs, evolution in the regulatory and/or power market rules, and advancements in transmission technology.

The Plan models system conditions on the three divisions of Orange and Rockland, namely, Eastern Division (Rockland County and North Bergen County, New Jersey), Central Division (Orange County and portions of Passaic County, New Jersey) and Western Division (Orange County, Sullivan County and Pike County, Pennsylvania). First contingency conditions were tested on the three divisions and identified thermal and voltage limit violations as well as the corresponding MW deficit. The Plan also identified solutions to mitigate these violations and recommended projects to eliminate the deficiencies in the Orange and Rockland transmission system. The recommended capital projects include the following:

1. Increasing the capacity of existing transmission components by:
    a. Re-conductor of existing transmission line with higher ampacity conductor or the use of high temperature low sag (HTLS) conductor;
    b. Installation of parallel transmission transformer;
    c. System modification of existing transmission facilities (i.e. termination of longer transmission lines on adjacent stations to create parallel transmission paths);
2. Upgrade of existing facility to higher voltage;
3. Installation of transmission capacitor banks at various transmission substations as well as distribution substations; or,
4. Combinations of the above.

# I. OVERVIEW

This document lays out Orange and Rockland Utilities' plan for the transmission system over a 10-year planning horizon[1]. Recognizing future uncertainties, the Plan should be viewed as a robust yet flexible framework or roadmap for direction rather than a well-defined series of projects to be implemented on a set schedule. Decisions on the implementation of specific projects are made based on reliability needs which are affected by numerous factors, including the economy, customer usage behavior, demand side management efforts and developer projects. Although the assumptions were based on the approved 2011-2015 Orange and Rockland Capital Budget, the Plan may change over time in order to adapt to future conditions and assumptions.

## A. Factors Affecting the Long-Range Transmission Plan

The following are the various factors that will affect the Plan:

- i. Changes in reliability requirements;
- ii. Changes in econometric load forecasts;
- iii. Impact of demand side management programs (DSM);
- iv. Impacts from the State's Energy Efficiency Portfolio Standard (EEPS) and Renewable Portfolio Standard (RPS) programs[2];
- v. Other state and national policy programs such as the Regional Greenhouse Gas Initiative (RGGI),
- vi. New merchant generation and transmission;
- vii. Decisions under the New York Independent System Operator's (NYISO's) Comprehensive Reliability Planning Process (CRPP)and FERC Order 890; and
- viii. Potential new legislation on the interconnection-wide planning process.

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[1] The posting and discussion of this document satisfies the requirements of Order 890 for openness and transparency in local transmission planning. The document itself constitutes the Local Transmission Plan (LTP) referred to in the NYISO tariff.

[2] The Governor has announced his desire for the State to meet a stretch goal named the "45 x 15" objective.

The studies that support the Plan reflect current assumptions regarding these factors. Conversely, the Plan needs to be updated periodically to capture, among other issues, updated assumptions.

## B. Orange and Rockland Transmission Planning Criteria

System expansion and the incorporation of new facilities must follow the established and published Orange and Rockland Transmission Planning Criteria[3]. The criteria document describes Orange and Rockland's transmission planning criteria for assessing the adequacy of its transmission system to withstand design contingency conditions while providing reliable supply to all its customers throughout the planning horizon. The document includes a description of the Company's transmission system design principles, performance criteria as well as thermal and voltage assessments. The Planning Criteria document is publicly available and posted on the Orange and Rockland website.[4]

All system expansions, whether by Orange and Rockland or by other parties, must be made in accordance and in compliance with NERC Standards, NPCC Criteria, NYSRC rules and NYISO procedures. As a member of the Northeast Power Coordinating Council (NPCC) in New York and ReliabilityFirst Corporation (RFC) in New Jersey, Orange and Rockland's planning process adheres to NPCC and RFC criteria.

The NPCC Criteria documents are designated as Type "A" and describe the minimum criteria applicable to NPCC members functioning as part of the coordinated interconnected network. Given their importance, the Criteria documents require the approval of two thirds of the NPCC membership. NPCC Guideline documents designated as Type "B" serve as the guide through which implementation of the criteria and acceptable system performance is achieved.

[3] Appendix A contains Orange and Rockland Transmission Planning Criteria.
[4] http://www.oru.com/documents/tariffsandregulatorydocuments/federal/TransmissionPlanningGuidelines.pdf

As a member of the New York State Reliability Council (NYSRC), Orange and Rockland must also adhere to the "NYSRC Reliability Rules for Planning and Operating the New York State Power System". NYSRC reliability rules may be more specific or stringent than NERC Standards and NPCC Criteria. Given the importance of NYSRC reliability rules, adoption or modification requires an affirmative vote of at least 9 out of the 13 members of NYSRC's Executive Committee.

## C. Relationship with FERC Order 890 and Order 2003

FERC Order 890 "*Preventing Undue Discrimination and Preference in Transmission Service*" requires reliability and economic processes for new transmission. In New York, the reliability planning process is the first step of the Comprehensive System Planning Process under the NYISO Open Access Transmission Tariff (OATT), which places primary emphasis on implementing new market-based merchant resources to meet a reliability need if there is a system capacity Loss of Load Expectation (LOLE) greater than 0.1 over a 10-year period. The Comprehensive Reliability Plan issued by the NYISO then identifies regulated backstop solutions to be developed by the appropriate Transmission Owners (TOs) that would be triggered by the NYISO if the market does produce a merchant solution in a timely manner.

Further, Order 890 contains certain principles to achieve the non- discriminatory, open and transparent goals of the planning process that must be followed by both the NYISO and the local Transmission Owners. The posting of this document and its discussion with interested parties are intended to satisfy these requirements. The NYISO sets a schedule[5] for meeting these requirements in advance of the Load and Capacity Data Report (Gold Book) used at the start of next Reliability Needs Assessment (RNA) cycle.

FERC Order 2003 "*Standardization of Generator Interconnection Agreements and Procedures"* established rules and procedures that govern large generation

[5] For 2011 the NYISO has announced a schedule that requires local TOs to post their local plans in September and make presentations to interested parties in October.

interconnections. In New York, parts of Order 2003 are addressed by tariff provisions in the NYISO OATT, Attachment X. Merchant generation can follow a defined process to interconnect at the location of its choice, and the TO's Long- Range Transmission Plan must take this into account. Further, TOs are required to meet load for a given year[6] with generic generation placed at feasible locations. Recently the NYISO has adopted a deliverability requirement, embedded in Attachments X of the NYISO OATT, in addition to the prior minimum interconnection standard. As a result of the application of this tariff, new generation may require changes and additions to the transmission system that must be also be reflected in all studies performed.

Since there are many reasons that may affect decisions on future generation, DSM and transmission, it is necessary to make reasonable assumptions on such changes in the development of the Plan. However, in all circumstances, the driver for the local Long-Range Transmission Term is maintaining reliability.

## D. Objectives

Orange and Rockland delivers electricity to approximately 290,000 electric customers in the southeastern portion of New York State, northern New Jersey, and northeastern Pennsylvania**.** The O & R territory is divided into three major divisions namely, Eastern Division (Rockland county and northern Bergen County, New Jersey), Central (eastern Orange county and portions of Passaic County, New Jersey) and Western Division (western Orange County, portions of Sullivan County and Pike County, Pennsylvania). Its major ties with the 345 kV bulk electric system includes five (5) 400 MVA 345/138 kV step down transformer and one (1) 115 kV line in New York and one (1) 400 MVA 345/138 kV step down transformer bank in New Jersey. In-area generation resources include several small generating plants (< 20 MW total) located in the eastern and western divisions of Orange and Rockland.

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[6] Attachment S of the NYISO OATT includes the concept of Class Year in which Generator Owners can place themselves so that the reliability of the system can be studied with the collective presence of all generators in the Class Year.

Therefore, the main objective of the Long-Range Transmission Plan is to maintain reliability on the 138 kV and 69 kV Orange and Rockland's transmission system during normal and emergency operating conditions.

Orange and Rockland has developed a set of objectives for the development of its Long-Range Transmission Plan in accordance with all applicable reliability criteria. The ability of the transmission system to perform in accordance with the Transmission Planning Criteria is periodically assessed as new load forecast information becomes available. This assessment can result in recommendations for specific upgrades, as discussed in more detail in Chapter 5 of this Plan[7].

## 1. Objective 1: Transmission System Assessment

Planning for the Orange and Rockland transmission system includes the detailed evaluation of 138 kV and 69 kV transmission facilities over a 10- year period. As distribution load forecasts are considered, it is possible that projections indicate that one or more reliability criteria would not be met at some date in the future. In such cases, remedial actions are developed and planned to assure the system continues to comply with reliability criteria. There are a number of possible actions that can address transmission system reliability criteria deficiencies:

1. Additional transmission lines on the existing right-of-way (ROW) or new ROW;
2. Increasing the capacity of existing transmission components by:
    a. Re-conductor of existing transmission line with higher ampacity conductor or the use of high temperature low sag (HTLS) conductor;
    b. Installation of parallel transmission transformer.

[7] Orange and Rockland, together with all other TOs in the State is participating in a separate planning program called STARS. Information on this initiative can be found on the NYISO website at http://www.nyiso.com/public/services/planning/stars.jsp

c. System modification of existing transmission facilities (i.e. termination of longer transmission lines on adjacent stations to create parallel transmission paths);

3. Upgrade of existing facility to higher voltage;
4. Installation of transmission capacitor banks in various transmission as well as distribution stations; and/or,
5. Combinations of the above.

Analysis is performed on a case-by-case basis to determine the most cost-effective remedial action. All are designed to bring the Transmission system into compliance with reliability criteria.

## 2. Objective 2: Interconnection of New Generation Resources

Reliability criteria can be met in some cases by the interconnection of new generation resources within the system or by interconnections to new or existing generation resources outside the system. New generation resources are not only a source of additional real power but are also a source of reactive power, all of which help bring the system into compliance with reliability criteria. Resources closer to load will provide greater reactive support than those further away. Other considerations include the provision of black start capabilities by units directly on the Orange and Rockland system as well as well as the provision of dual fuel capability, both of which contribute to maintaining reliability. At some point, the interconnection of new generation resources is needed to meet reliability and supply requirements.

# II. LONG-RANGE TRANSMISSION PLAN ANALYSIS TOOLS AND METHODOLOGIES

Orange and Rockland's transmission system is assessed using a variety of system modeling and simulation tools to measure the transmission system's capabilities against design criteria. This is done for present and planned configurations at present and future load levels, respectively. The simulations are validated using real-time measurements made under normal and contingency conditions whenever possible. Assessments are made in the following areas, using standardized software packages to study the system's performance:

- Thermal;
- Voltage;
- Short Circuit;
- Under-frequency Load Shedding;
- Extreme Contingencies;
- Equipment Replacements Due to Condition.

## A. Thermal

Load flow studies are the primary method used by Transmission Planning to assess the performance of the transmission system under normal and contingency conditions. The software used for these studies is provided by Power Technologies International, a division of Siemens AG, and is referred to as PSS/E, the acronym for Power System Simulator / Engineering. This is the leading software package for bulk transmission system load flow studies.

The load flow levels established by the studies are measured against the thermal ratings of transmission facilities. Transmission equipment including lines and transformer banks are assigned with thermal ratings for normal operation, long-time emergency operation (LTE), and short-time emergency operation (STE).

Load flow studies are conducted to simulate normal operation under peak forecast loads. No transmission facilities should exceed their normal ratings at this operating condition. During single contingency conditions, no facilities should exceed their LTE ratings. Also following the various contingency conditions defined in the New York State Reliability Council (NYSRC) and the Northeast Power Coordinating Council (NPCC) rules, the Orange and Rockland transmission system must exhibit the capability to be returned to operation within normal thermal limits following the worst case single contingency within the time frame specified in the rules.

## FERC Form 715

While load flow studies are conducted year-round by Transmission Planning for a wide variety of analyses, including planned expansions and real-time contingencies, overall system-wide assessments are required once a year to support the NYISO's requirement to file FERC Form 715, the Annual Transmission Planning and Evaluation Report. This is a comprehensive effort that includes updating the system model in terms of configuration and impedances, and adjusting the transmission system for optimum power flows. FERC 715 filing is done for the 5$^{th}$ year (Summer Peak, Winter peak and Light Load), and 10$^{th}$ year (Summer peak Only), as well as the operating system task force(OSTF) base cases are added for the starting year (Summer and Winter Peak). The future cases incorporate all planned changes such as additions, expansions, and retirements according to the scheduled timelines for these changes. Load flow base cases developed for the FERC 715 filing are used for annual reviews of Installed Reserve Margin (IRM), a NYSRC requirement. Load flow base cases developed for the FERC 715 filing are also used in the NYISO's Comprehensive Reliability Planning Process (CRPP) which is conducted annually looking out over a ten-year horizon, one year at a time. The first task in the CRPP is to conduct a Reliability Needs Assessment (RNA). If a reliability need or needs are identified in any or all of the ten years studied, a Comprehensive Reliability Plan (CRP) must be formulated to meet that need or those needs.

## B. Voltage

Voltages throughout the transmission system are checked using the same load flow studies that are used to make the thermal assessments described in the section above. The focus, however, shifts from the delivery of real power, measured in MW, to voltage support and control provided by reactive power, measured in MVAR[8].

## C. Short Circuit

Short circuit studies are conducted using the ASPEN program. These are done to assess:

1. The ability of circuit breakers on the transmission system to interrupt fault currents; and

2. The ability of all equipment on the transmission system, including but not limited to circuit breakers, bus work, disconnect switches, and structural supports to withstand the mechanical forces associated with fault currents. Momentary forces generated within the first one-half cycle following the inception of a fault typically present the highest mechanical stresses.

The NYISO conducts semi-annual updates of its short circuit base case models, one each for the summer and winter seasons. Significant data for these studies include system configuration, i.e., network topology, impedances of all connected equipment, and circuit breaker interrupting ratings.

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[8] Voltages must remain within a prescribed range of 0.95 to 1.05 per unit through all contingencies studied under the NYSRC rules.

## D. Under-frequency Load Shedding

Under-frequency relays are installed at various locations throughout the system to provide protection against widespread system disturbances. The Under-frequency Load Shedding Program (UFLS) is updated each year for the NYISO and PJM control areas.

### 1. Circuit Weight

A circuit weight is calculated annually for each circuit based on the priority of the customers that are located on the circuit. For example,

(a) A circuit contains a hospital (150), a nursing home (25) and a prison (2) would have a circuit weight of 177.

(b) An artificial weight is given for the two circuits that feed the O & R SVOC building.

The available circuits with under-frequency relays are then prioritized by circuit weight. Excluding circuits with high priority customers, such as hospitals and malls, the UF relays are then turned on for the higher-weighted circuits until the cumulative load for these circuits reaches the requirement for each level. The under-frequency relays for the remaining circuits are turned off.

### 2. Under-frequency relays:

i. The **Northeast Power Coordinating Council (NPCC)** requirements are for two frequency settings based on the previous year's peak. The first setting requires 10% of the previous year's peak plus 25% of the curtailables and co-generation used during the previous year's peak to be shed at 59.3 hertz. The second setting requires 15% of the previous year's peak to be shed at 58.8 hertz.

ii. The **Reliability-First Corporation (RFC)** requirements are for three frequency settings based on forecasted peak. The first setting requires 10% of the year's forecasted peak to be shed at 59.3hertz. The second setting requires 10% of the year's forecasted peak to be shed at 58.9 hertz. The third setting requires 10% of the year's forecasted peak to be shed at 58.5 hertz.

## E. Extreme Contingencies

Extreme contingency scenarios that stress the transmission system beyond its design criteria are assessed in accordance with NPCC Document B-4, "Guidelines for NPCC Area Transmission Reviews". Document B-4 states that extreme contingency assessment, similar to stability assessment, is to be part of the Comprehensive Review conducted once every five years in each of the NPCC areas. The NYISO conducts the Comprehensive Review for the New York Control Area. Beyond this requirement, Orange and Rockland also periodically conducts extreme contingency assessments for its own transmission system. The intent is to gauge the extent of customer and overall system impact that could be incurred under selected worst case scenarios involving multiple contingencies, and to identify potential mitigating actions that could be taken to minimize the adverse impact. The results of the extreme contingency tests are published in Orange and Rockland's annual Transmission System Summer Peak Operating Study ("Summer Study"). These results are for information purposes only, therefore, no corrective measures are identified to mitigate these extreme contingency cases.

## E. Equipment Replacements Due to Condition

The condition of major equipment in the system such as transformers, breakers and switchgears are also taken into account. The recommended number of years in service for equipment prior to change out is about 50 years.

# III. BASE CASES MAJOR ASSUMPTIONS

The analysis presented in this document is performed on a yearly cycle and takes close to eighteen months to carry out and review. The studies are based on assumptions that were published in Orange and Rockland's annual Summer Study.

## Long-Range Transmission Plan Assumptions[9]

| Study Year | System Peak Assumptions |
|---|---|
| 2011 | Orange and Rockland Projected System Peak = **1625 MW** |
| 2015 | Orange and Rockland Projected System Peak = **1740 MW** |
| 2020 | Orange and Rockland projected System Peak = **1875 MW** |

| Study Year | In-Area Generation Resources Assumptions |
|---|---|
| 2011 | No new generation in service |
| 2015 | No new generation in-service |
| 2020 | No new generation in-service |

| Study Year | Demand Side Management (DSM) Assumptions |
|---|---|
| 2011 | 4.8 MW (Initial reduction) |
| 2015 | 40.6 MW (Cumulative reduction) |
| 2020 | 57.0 MW (Final cumulative reduction) |

| Study Year | Capital Projects Assumptions |
|---|---|
| 2011 | Capital projects identified in the Budget are in service prior to summer of 2011. |
| 2015 | Capital projects identified in the Budget will be in service prior to summer of 2015. |
| 2020 | Capital projects identified in the Budget will be in service prior to summer of 2020. |

[9] These assumptions supplement or replace the comparable assumptions in the FERC 715 Annual transmission Planning and Evaluation Report filed by the NYISO in April, 2011.

# VI. DEVELOPMENT OF THE LONG-RANGE TRANSMISSION PLAN

This chapter presents the requirements, procedures, and scheduling that will be necessary for the development of the Long-Range Transmission Plan. The process is designed to be completed in 18 months from beginning to end.

The process timeline is now designed to dovetail with the scheduling requirements of FERC Order 890, which requires a local transmission plan to be posted for public review in the September timeframe in sufficient time for meaningful review and comments prior to the inputs that need to be provided for the NYISO's Comprehensive System Planning Process (CSPP).

## A. General Description of the Contingency Evaluation Process

Orange and Rockland is required by NERC, NPCC and NYSRC rules to maintain its transmission system so that the worst contingency during the highest load period will not result in equipment loading that exceeds the designated emergency rating of that equipment and also will not result in the loss of any customer service. The system operator should initiate criteria corrective action within four (4) hours that will not result to equipment loading that does not exceed the designated normal rating of that equipment[10].

A single contingency, designated "N-1," is defined as a single loss of any individual piece of equipment along with associated infrastructure that would be lost as a result of the loss of that equipment. Generally, this may be the loss of a single transmission line, the failure of a circuit breaker, switch, or outage of a single circuit in a transmission tower, or relay operations causing the outage of a single transmission line and/or the outage of station.

[10] See Orange and Rockland's Transmission Planning Guidelines (Appendix A).

## B. Long-Range Transmission Plan Process Milestones and Schedule

For every 18-month cycle, the Long-Range Transmission Plan process begins after the issuance of the NYISO's Gold Book describing the summer conditions for the year prior to the first study year of this Plan:

1. Summer peak load period for year 1 of the study;
2. Summer peak load for year 5 of the study; and
3. Summer peak load for year 10 of the study.

The NYISO, with input from the TOs on changes to their transmission system and on their load forecast develops a summer model for the entire New York system. This provides the model for areas outside the Orange and Rockland system for the studies reported in the Plan. To define the internal portions of the model, the first step is to take the independent peaks for each Distribution Substation in the three (3) divisions which are available after the summer and perform a spreadsheet tabulation evaluation to identify possible deficiencies as an early signal of potential problem areas. In the fourth quarter, after the coincident load forecast for each area station is available, the load flow base cases for the three timeframes of the study are developed. Starting in the first quarter of the study year load flow analysis for the whole transmission system using the three timeframes is conducted. Short circuit analysis is also performed in areas where there have been significant model or generation changes. The second quarter of the study year is devoted to the evaluation of the results of these analyses and the development and verification of potential solutions. Finally during the summer period the Plan is thoroughly reviewed and the report is drafted.

Special note should be taken that the model for the first year of evaluation (2011 for the current Plan) contains the NYISO's forecasted loads for the summer of the previous year (2010) for the non-Orange and Rockland portions and the summer forecasted loads for the first year of the study (2011) for the Orange and Rockland system. This is necessary for the timely completion of the analysis because the NYISO forecasted loads for the first year of evaluation are not ready until just prior to the summer of that year.

These steps are described in detail below:

1. **Orange and Rockland Model to NYISO for years 0, 5 and 10** (2010, 2015 and 2020)

   Orange and Rockland works collaboratively with the NYISO to build an accurate representation of the Orange and Rockland transmission system and its load as a component of the NYISO load model;

2. **NYISO Model to Orange and Rockland for Years 0, 5 and 10** (2010, 20156 and 2020)

   The NYISO collects all of the component models of each contributing Transmission Owner and generation entity within the state and surrounding areas, and combines them into a single model which is then distributed to all utilities. Generators that are in the NYISO interconnection process for future establishment are not included in the model unless they meet certain NYISO criteria, including being under construction;

3. **Obtain Independent Peaks by Station for Years 1, 5 and** 10 (2010, 2016 and 2020)

   Orange and Rockland's Distribution Engineering Department determines the distribution substation load forecasts after the summer of each year, based on the most current summer load information for each substation. The independent peaks of each of the distribution substations will be available by the start of the fourth quarter;

4. **Evaluation of individual substation peaks for Years 1, 5 and 10** (2011, 2015 and 2020)

   The individual substation peaks combined with a diversity factor in order to provide a rough estimate of the MW margin or deficiency of a particular substation. These results are generally optimistic by design;

5. **Obtain weather normalized Peaks for Years 1, 5 and 10** (2011, 2015, 2020)

   Following the determination of the independent peaks for each substation, the weather normalized peaks to be used in the load model are determined in the fourth quarter. This data will be incorporated into the Orange and Rockland portion of the NYISO load flow models;

6. **Define the Orange and Rockland Portion of the Models for Years 1, 5 and 10** (2011, 2015 and 2020)

   Each Orange and Rockland distribution station is updated with the latest load data including any major block loads, transfer of significant loads to adjacent stations, creation of new adjacent substations that will provide load relief or load back-up for an existing station and any load retirements;

7. **Load Flow Studies for the three divisions using the 3 Snapshot Years**

   During the first quarter of year 1 of the study, the load models are evaluated for each of the 3 years in question. A list of N-1 contingency conditions are modeled and tested;

8. **Problems Identified**

   Thermal overloads and voltage violations may require pre- contingency adjustments to the system (such as pre-loading transmission lines, or reactive compensation, etc.) in order to resolve post-contingency violations.

   Thermal overloads and voltage violations that cannot be corrected will be identified according to the year of appearance, extent of violation, growth of the problem over time, and potential of remediation through scheduled or anticipated infrastructure improvements;

9. **Solutions Proposed and Evaluated**

For all thermal overloads and voltage violations that cannot be corrected using actions permissible within the transmission planning criteria, the impact of various system enhancements are evaluated according to their feasibility, timely establishment, extent of impact, and cost, and the one that most optimally satisfies the reliability, economic and operational requirements of the Transmission System is selected;

10. **Report and Presentation**

The results of the analysis performed for each division are included in the annual Long-Range Transmission Plan; and

11. **FERC Order 890 Presentations and Responses**

In accordance with the requirements set forth in FERC Order 890, the Plan is posted and presented to interested parties. The intent is to provide information on the local transmission plan early in the planning cycle so as to provide a meaningful opportunity for comments.

## C. Design Criteria Requirements

1. **Thermal Overloads and Voltage Violations**

Thermal overloads occur when the complex power, or MVA, on a transmission path exceed the normal rating of that path. These overloads can be caused by excessive real power flow, reactive power flow, or a combination of both. Voltage violations occur when bus voltages exceed their limits either above or below their nominal ratings.

For Overhead lines and inter-utility ties, Orange and Rockland transmission planning design criteria for every "loss of transmission path" contingency is evaluated such that:

a. Immediately following the contingency and prior to any criteria corrective action, the flow on any path does not exceed the Long Term Emergency rating of that path; and

b. Following criteria corrective action (steady state), the flow on the path may not exceed the normal rating of that path.

**2. Short-Circuit Violations**

Short-Circuit Violations occur when a 3-phase fault, 2-phase fault or single line to ground fault create a short-circuit flow on a transmission path which exceeds the appropriate short-circuit rating of any of the breakers that are necessary for the isolation of that transmission path.

## D. Methods for Deficit Resolution through System Enhancements

When criteria corrective actions are deemed insufficient or inappropriate for resolving post-contingency problems, strategies for the resolution of deficits through system enhancements are identified. Various solutions are modeled and evaluated for every problem, based on extent of impact, reliability improvement, scheduling, and cost. The following solution concepts are considered:

**1. Load Transfers**

Distribution Substation load transfers that reduce load within a specific area may be sufficient to reduce or eliminate deficits found in a certain area.

Advantages: Economical, fast, may support other organizational goals.

Disadvantages: May limit future growth in other areas, may interfere with other organizational goals.

2. **Upgrades to Infrastructure**

Enhancements to transmission lines, circuit breakers, transformers, or bus works can increase the ability to import power into an area. Upgrades will include but not limited to re-conductoring with higher ampacity conductor or with a high temp low sag (HTLS) conductor, replacement of equipment, installation of parallel equipment such as lines and transformers, conversion to higher voltage class, among others.

Advantages: Permanent improvement in capacity, more economical than building new infrastructure.

Disadvantages: May require significant outage time, more expensive than load transfers.

3. **New Generation or Upgrades**

The timely establishment of new generation or the upgrade of existing generation can have a major impact on reducing transmission system deficits. Generally, anticipated generation is not considered unless construction has begun. Orange and Rockland closely monitors the status of all generation projects in the NYISO queue that can have an impact within the Orange and Rockland service territory.

Advantages: Permanent improvement in capacity.

Disadvantages: Merchant generation not under the control of Orange and Rockland, long period from concept to operation; May need short-circuit mitigation.

4. **New or Reconfiguration of Transmission Lines**

New transmission lines increase the ability to import power into an area by providing an alternative path for support following a contingency. Sometimes, it can be sufficient to reconfigure a line to improve reliability, either by relocating a termination point to another station, or by relocating the termination point within a station. Consideration must be taken for any increase in short-circuit magnitudes.

Advantages: Permanent improvement in capacity, reliability.

Disadvantages: Cost, long lead times, may need short-circuit mitigation.

**5. New Transmission Switching Stations with New or Reconfigured Transmission Lines**

Transmission switching stations can be established according to the need for load relief in support of area stations that have reached their capacity. In most cases, these new transmission stations will also provide new transmission line connections or pathways that improve capacity and deliverability.

Advantages: Permanent improvement in capacity.

Disadvantages: Expensive, long lead time.

**6. Transmission Station Configuration Upgrades**

Transmission stations can be reconfigured or expanded to provide reliability improvements. Isolated bus configurations can be effectively upgraded to ring bus or breaker-and-a-half configurations. Consideration must be taken for any increase in short-circuit magnitudes.

Advantages: Permanent improvement in capacity, reliability, cost.

Disadvantages: Cost, long lead times, may need short-circuit mitigation

**7. Reactive Power Compensation (Capacitors)**

The need for reactive power compensation varies according to the structure and function of various transmission and sub- transmission components. Overhead transmission lines need to carry a large volume of power, and may be limited by low voltage constraints. The most efficient and economical support for deliverability is the installation of shunt capacitor banks to inject reactive power into the transmission path and maintain high voltage along the transmission corridor.

Advantages: Permanent improvement in compensation, lower cost, short lead time.

Disadvantages: Shunt devices are subject to fluctuation as a function of voltage. Capacitor banks must be evaluated for contribution to transients during switching.

**8. Installation of Power Flow Control Devices (Phase Angle Regulators, Variable Frequency Transformers)**

Phase angle regulators (PAR's) and Variable Frequency Transformers (VFT's) may be installed in the system to control the real power flow on a transmission path needs to be regulated.

Advantages: Permanent improvement in reliability.

Disadvantages: Cost, long lead time, relatively large equipment.

**9. Short Circuit Remediation**

As generators are added to the system and as new transmission ties create more connections between stations, the overall level of short- circuit current magnitudes will increase. To reduce short-circuit currents higher impedance devices such as series reactors or phase angle regulators can be added to the system.

Advantages: Allows for more interconnections between stations, more economical than other alternatives such as DC back-to-back links.

Disadvantages: Absorb reactive power, reduces voltages.

**10. Demand Side Management (DSM)**

Permanent DSM can delay or replace the costly implementation of alternative infrastructure improvements.

# V. TRANSMISSION SYSTEM ASSESSMENT

The following table lists the three divisions within the Orange and Rockland Transmission system. This is followed by individual tables for each division containing the results of first contingency (N-1) analysis together with pre- and post project assessments as well as short circuit evaluations.

| | DIVISIONS | AREA COVERED |
|---|---|---|
| 1 | **EASTERN** | - Rockland County<br>- North Bergen County (New Jersey) |
| | | |
| 2 | **CENTRAL** | - Orange County<br>- Portions of Passaic County (New Jersey) |
| | | |
| 3 | **WESTERN** | - Orange County<br>- Portions of Sullivan County<br>- Portions of Pike County (Pennsylvania) |

## LOCAL PLANS AND ASSESSMENT

Each division will have the following proposed projects and with their corresponding proposed in-service dates:

1. Major transmission local plans and their respective assessments;
2. Short circuit assessment;
3. Proposed transmission capacitor bank installations; and,
4. Proposed equipment replacements due to condition.

## A. Eastern Division Local Plans and Assessment

| | |
|---|---|
| **GEOGRAPHIC COVERAGE** | Rockland County<br>North Bergen County |
| **DESIGN CRITERIA** | First Contingency |

| **MAJOR LOCAL TRANSMISSION PLANS** | | | | | | |
|---|---|---|---|---|---|---|
| **PROJECT DESCRIPTION** | **IN-SERVICE DATE** | | **PLANNING CRITERIA** | **WORST CONTINGENCY** | **AFFECTED FACILITIES** | **REMARKS** |
| | 2009 Plan | **2011 Plan** | | | | |
| **NORTH ROCKLAND 345KV STATION** | Dec 2013 | **Dec 2017** | N-1 Thermal Rating Violation | Loss of West Haverstraw Bank 194 | Line 60 above STE<br>Line 652 Above LTE | Install 400 MVA 345/138 kV Bank |
| **LINE 55 UPGRADE TO 138 KV** | Dec 2015 | **Dec 2018** | N-1 Thermal Rating Violation | Loss of Line 561 | Bank 147 above STE<br>Line 55 above STE | Convert Lovett to West Nyack 69 kV |
| **LINE 751** | - | **June 2011** | N-1 Thermal Rating Violation | Loss of Line 702 | Line 49 above LTE | Re-conductor Line 49 in HTLS. |

| ASSESSMENT (NORTH ROCKLAND 345 kV STATION) | | | | |
|---|---|---|---|---|
| **SUMMER YEAR** | **N-1 CONDITIONS** | **AFFECTED EQUIPMENT** | **MW DEFICIT** | **REMA** |
| 2016 | Loss of Bank 194 | Line 60 above LTE | 5 MW | Pre-installation of bank |
| | | Line 652 above LTE | 10 MW | |
| 2017 | Loss of Bank 194 | Line 60 above STE | 8 MW | Pre-installation of bank |
| | | Line 652 above STE | 13 MW | |
| 2017 | Loss of Bank 194 | NONE | NONE | Year of installation |
| 2020 | Loss of Bank 194 | NONE | NONE | Post-installation of bank |

| ASSESSMENT (LINE 55 UPGRADE TO 138 KV) | | | | |
|---|---|---|---|---|
| **SUMMER YEAR** | **N-1 CONDITIONS** | **AFFECTED EQUIPMENT** | **MW DEFICIT** | **REMARKS** |
| 2012 | Loss of Line 561 | Bank 147 below LTE | - | Pre- Upgrade |
| | | Line 55 below LTE | - | |
| 2016 | Loss of Line 561 | Bank 147 below LTE | - | Pre-Upgrade |
| | | Line 55 below LTE | - | |
| 2018 | Loss of Line 561 | Bank 147 above LTE | 15 MW | Pre-Upgrade |
| | | Line 55 above LTE | 15 MW | |
| 2018 | Loss of Line 561 | NONE | - | Year of Upgrade |
| 2021 | Loss of Line 561 | NONE | - | Post Upgrade |

| ASSESSMENT (LINE 751) | | | | |
|---|---|---|---|---|
| **SUMMER YEAR** | **N-1 CONDITIONS** | **AFFECTED EQUIPMENT** | **MW DEFICIT** | **REMA** |
| 2011 | Loss of Line 75 | Line 751 above LTE | 20 MW | Pre-upgrade |
| 2011 | Loss of Line 75 | Line 751 below LTE | - | Year of upgrade |
| 2015 | Loss of Line 75 | NONE | NONE | Post upgrade |
| 2020 | Loss of Bank 194 | NONE | NONE | Post upgrade |

| EASTERN DIVISION SHORT CIRCUIT ASSESSMENT | |
|---|---|
| **YEAR** | **AFFECTED BREAKERS** |
| 2009 | NONE |
| 2013 | NONE |
| 2018 | NONE |

| EASTERN DIVISION PROPOSED TRANSMISSION CAPACITOR BANK INSTALLATIONS | | | |
|---|---|---|---|
| **STATION** | **IN–SERVICE YEAR** | | **MVAR** |
| | **2009 PLAN** | **2011 PLAN** | |
| Snake Hill | 2010 | **2012** | 32 |
| Little Tor | 2010 | **2013** | 32 |
| New Hempstead | 2012 | **2014** | 32 |
| Tappan | 2013 | **2013** | 32 |
| Montvale | 2013 | **2013** | 32 |
| Pomona | 2015 | **2016** | 32 |
| **Summit** | - | **2017** | 32 |
| West Nyack | 2015 | **2018** | - |
| Central Rockland | 2017 | **2020** | 32 |

| EASTERN DIVISION PROPOSED EQUIPMENT REPLACEMENTS DUE TO CONDITION | | |
|---|---|---|
| **YEAR** | **STATION** | **EQUIPMENT** |
| 2016 | Ramapo | 138 kV Breakers |
| 2018 | West Haverstraw | 138 kV Breakers |
| 2018 | Burns | 138 kV Breakers |

## B. Central Division Local Plans and Assessment

| | |
|---|---|
| **GEOGRAPHIC COVERAGE** | Orange County<br>Portions of Bergen County |
| **DESIGN CRITERIA** | First Contingency |

| **MAJOR LOCAL TRANSMISSION PLANS** | | | | | | |
|---|---|---|---|---|---|---|
| **PROJECT DESCRIPTION** | **IN-SERVICE DATE** | | **PLANNING CRITERIA** | **WORST CONTINGENCY** | **AFFECTED FACILITIES** | **REMARKS** |
| | 2009 Plan | **2011 Plan** | | | | |
| **LINE 28 RAMAPO TO SUGARLOAF** | June 2010 | **Dec 2011** | N-1 Thermal Rating Violation | Loss of Middletown Tap Bank 114 | SL Line 60 above STE | Mirror Line 77 construction.<br>In parallel with existing 138 kV Line 26. |
| **STERLING FOREST NEW 69 KV SOURCE** | May 2015 | **May 2014** | N-1 Voltage Limit Violations | Loss of Line 993 or Loss of Line 89 | Widespread low voltage on various 69 kV busses | Install 200 MVA 138/69 kV bank and will feed into Sterling forest station. |
| **LINE 24 & LINE 25 CONVERSION TO 138 KV** | - | **Dec 2017** | | | | |

| ASSESSMENT (LINE 28 RAMAPO TO SUGARLOAF) | | | | |
|---|---|---|---|---|
| **SUMMER YEAR** | **N-1 CONDITIONS** | **AFFECTED EQUIPMENT** | **MW DEFICIT** | **REMARKS** |
| 2011 | Loss of Bank 114 | SL Line above STE | 90 MW | Pre-installation of bank |
| 2012 | Loss of Bank 114 | NONE | NONE | Post-installation |
| 2016 | Loss of Bank 114 | NONE | NONE | Post-installation of bank |
| 2021 | Loss of Bank 114 | NONE | NONE | Post-installation of bank |

| ASSESSMENT (STERLING FOREST NEW 69 KV SOURCE) | | | | |
|---|---|---|---|---|
| **SUMMER YEAR** | **N-1 CONDITIONS** | **AFFECTED EQUIPMENT** | **MW DEFICIT** | **REMARKS** |
| 2011 | Loss of Line 993 | Low voltage on various 69 kV stations | - | Pre- installation |
| | Loss of Line 89 | Low voltage on various 69 kV stations | - | |
| 2014 | Loss of Line 993 | Low voltage on various 69 kV stations | - | Pre-installation |
| | Loss of Line 89 | Low voltage on various 69 kV stations | - | |
| 2014 | Loss of Line 993 | NONE | NONE | Year of installation |
| | Loss of Line 89 | NONE | NONE | |
| 2021 | Loss of Line 993 | NONE | NONE | Post Installation |
| | Loss of Line 89 | NONE | NONE | |

| ASSESSMENT (LINE 24 and LINE 25) | | | | |
|---|---|---|---|---|
| **SUMMER YEAR** | **N-1 CONDITIONS** | **AFFECTED EQUIPMENT** | **MW DEFICIT** | **REMARKS** |
| 2011 | NONE | NONE | NONE | NONE |
| 2015 | NONE | NONE | NONE | NONE |
| 2020 | NONE | NONE | NONE | NONE |

| CENTRAL DIVISION SHORT CIRCUIT ASSESSMENT | |
|---|---|
| **YEAR** | **AFFECTED BREAKERS** |
| 2011 | NONE |
| 2015 | NONE |
| 2020 | NONE |

| CENTRAL DIVISION PROPOSED TRANSMISSION CAPACITOR BANK INSTALLATIONS | | | |
|---|---|---|---|
| **STATION** | **IN–SERVICE YEAR** | | **MVAR** |
| | 2009 PLAN | **2011 PLAN** | |
| Hartley | 2011 | **2012** | 32 |
| West Warwick | 2012 | **2015** | 32 |
| Woodbury | 2016 | **2017** | 32 |

| CENTRAL DIVISION PROPOSED EQUIPMENT REPLACEMENTS DUE TO CONDITION | | |
|---|---|---|
| **YEAR** | **STATION** | **EQUIPMENT** |
| 2012 | Sugarloaf | 138 kV Breakers |

## 5.3. Western Division Local Plans and Assessment

| | |
|---|---|
| **GEOGRAPHIC COVERAGE** | Orange County<br>Sullivan County<br>Portions of Pike County (Pennsylvania) |
| **DESIGN CRITERIA** | First Contingency |

<table>
<tr><th colspan="7">MAJOR LOCAL TRANSMISSION PLANS</th></tr>
<tr><th rowspan="2">PROJECT DESCRIPTION</th><th colspan="2">IN-SERVICE DATE</th><th rowspan="2">PLANNING CRITERIA</th><th rowspan="2">WORST CONTINGENCY</th><th rowspan="2">AFFECTED FACILITIES</th><th rowspan="2">REMARKS</th></tr>
<tr><th>2009 Plan</th><th>2011 Plan</th></tr>
<tr><td rowspan="2">2nd MIDDLETOWN TAP (Northern 345 kV Tap)</td><td rowspan="2">Dec 2016</td><td rowspan="2">June 2020</td><td>Normal Thermal Rating Violation</td><td>N/A</td><td>Middletown Tap Bank 114 above normal rating.</td><td rowspan="2">Install new 400 MVA 345/138 kV bank</td></tr>
<tr><td>N-1 Thermal and Voltage Limit Violations</td><td>Loss of Middletown Tap Bank 114</td><td>Line 28 exceeds LTE<br>Line 26 Exceeds LTE<br><br>Widespread low voltage in 139 kV and 69 kV busses</td></tr>
<tr><td>LINE 6 UPGRADE TO 69 KV</td><td>Dec 2016, Dec 2017, Dec2018 (Various stages)</td><td>Dec 2017, Dec 2018, Dec 2019, Dec 2020 (Various stages)</td><td>N/A</td><td>N/A</td><td>N/A</td><td>Creation of 69 kV loop in the northern part of the western division for more reliability in the area.</td></tr>
</table>

| ASSESSMENT (CUDDEBACKVILLE NEW 345 KV STATION) | | | | |
|---|---|---|---|---|
| **SUMMER YEAR** | **N-1 CONDITIONS** | **AFFECTED EQUIPMENT** | **MW DEFICIT** | **REMARKS** |
| 2011 | Loss of Bank 114 | NONE | - | Pre-installation of bank |
| 2015 | Normal operation | Bank 114 above normal | 15 MW | Pre-installation of bank |
| | Loss of Bank 114 | Line 28 approaches LTE | - | Pre-installation of bank |
| | | Line 26 above LTE | - | Pre-installation of bank |
| 2020 | Normal operation | Bank 114 above normal | 30 MW | Pre-installation of bank |
| | Loss of Bank 114 | Line 28 above LTE | 20 MW | Pre-installation of bank |
| | | Line 26 above LTE | 20 MW | Pre-installation of bank |
| 2020 | Normal operation | NONE | - | Post-installation of bank |
| | Loss of Bank 114 | NONE | - | Post-installation of bank |
| 2021 | Normal operation | NONE | - | Post-installation of bank |
| | Loss of Bank 114 | NONE | - | Post-installation of bank |

| ASSESSMENT (LINE 6 UPGRADE TO 69 KV) | | | | |
|---|---|---|---|---|
| **SUMMER YEAR** | **N-1 CONDITIONS** | **AFFECTED EQUIPMENT** | **MW DEFICIT** | **REMARKS** |
| 2011 | NONE | NONE | NONE | Pre- upgrade |
| 2015 | NONE | NONE | NONE | Pre-upgrade |
| 2020 | NONE | NONE | NONE | Post-upgrade |

| WESTERN DIVISION SHORT CIRCUIT ASSESSMENT | |
|---|---|
| **YEAR** | **AFFECTED BREAKERS** |
| 2011 | NONE |
| 2015 | NONE |
| 2020 | NONE |

| WESTERN DIVISION PROPOSED TRANSMISSION CAPACITOR BANK INSTALLATIONS | | |
|---|---|---|
| **YEAR** | **STATION** | **MVAR** |
| 2014 | Pocatello | 32 |
| 2015 | Fair Oaks | 16 |
| 2016 | Milford | 16 |

| WESTERN DIVISION PROPOSED TRANSMISSION CAPACITOR BANK INSTALLATIONS | | | |
|---|---|---|---|
| **STATION** | **IN–SERVICE YEAR** | | **MVAR** |
| | 2009 PLAN | **2011 PLAN** | |
| Pocatello | 2014 | **2016** | 32 |
| Fair Oaks | 2015 | **2017** | 16 |
| Milford | 2016 | **2020** | 32 |
| Bullville | 2017 | **2019** | 16 |

| WESTERN DIVISION PROPOSED EQUIPMENT REPLACEMENTS DUE TO CONDITION | | |
|---|---|---|
| **YEAR** | **STATION** | **EQUIPMENT** |
| **2020** | **Rio** | **69-13.2 kV Bank** |

# 6. SUPPLEMENTAL STUDIES

There are no supplemental studies conducted by Orange and Rockland in its service territory.

# APPENDIX A

# (Orange and Rockland's Transmission Planning Guidelines – Version 2)

Orange & Rockland
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# TRANSMISSION PLANNING GUIDELINES
## (Revision 2)


Prepared by:

Roleto Mangonon, Senior Engineer
Transmission and Substation
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Reviewed by:

John Coffey, Chief Engineer
Transmission and Substation
Engineering Department



Date Issued: June 25, 2011(Rev. 2)

Next Review: June, 2012



Approved by:

Angelo Regan, Director
Engineering

| REVISION TABLE | | | |
|---|---|---|---|
| **Revision Level** | **Author** | **Date** | **Description** |
| Original | - | 1991 | - None |
| 1st Revision | R. Mangonon | 05/01/2008 | - Updated Cover page and Table of Contents.<br>- Revised Part I & II.<br>- Added Part III & IV. |
| 2nd Revision | R. Mangonon | 06/25/2011 | - Updated Cover page and Table of Contents.<br>- Added Revision Table.<br>- Added Sections I, II & VIII.<br>- Updated Reference Page. |
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# TRANSMISSION PLANNING GUIDELINES

## I. INTRODUCTION

Orange and Rockland's Transmission and Substation Engineering Department (TSED) has the tasked of ensuring the reliability and adequacy of the local transmission system while meeting system load growth. TSED conducts annual comprehensive studies that results to local transmission plans. In developing these plans, TSED uses the principles and guidelines mentioned in this document to ensure that Orange and Rockland's local transmission system is capable of serving current and projected distribution loads during normal and emergency conditions. These planning guidelines are meant to supplement the New York Independent System Operator (NYISO) and Pennsylvania Jersey Maryland Interconnection (PJM) current planning process.

## II. BULK POWER SYSTEM

### A. DEFINITION

For the New York Control Area (NYCA), all facilities at 230 kV and above are considered as bulk power including lines, transformer banks where both high and low side terminals at are least 230 kV, shunt devices and generators at 300 MW and above. Planning guidelines and criteria for these facilities are defined by North American Reliability Corporation (NERC), Northeast Power Coordinating Council (NPCC) and the New York State Reliability Council (NYSRC). These facilities are determined as bulk power by the application of the methodology defined by NPCC's A-10. Bulk power transmission planning is covered by NYISO's planning process. The analysis and studies performed by the NYISO include, but not limited to, thermal, voltage, stability, short circuit and breaker duty and transfer limits.

For the New Jersey Control Area (NJCA), the bulk electric system is defined as all:

(1) Individual generation resources larger than 20 MVA or a generation plant with aggregate capacity greater than 75 MVA that is connected via a step-up transformer(s) to facilities operated at voltages of 100 kV or higher,

(2) Lines operated at voltages of 100 kV or higher,

(3) Transformers (other than generator step-up) with both primary and secondary windings of 100 kV or higher, and

(4) Associated auxiliary and protection and control system equipment that could automatically trip a BES facility, independent of the protection and control equipment's voltage level.

Planning guidelines and criteria for these facilities are defined by North American Reliability Corporation (NERC) and Reliability First Corporation (RFC). Bulk electric transmission planning is covered by PJM's planning process. The analysis and studies performed by the PJM include, but not limited to, thermal, voltage, stability, short circuit and breaker duty and transfer limits.

**B. RELIABILITY**

The reliability criteria, guidelines and policies for the NYCA facilities shall be defined by NERC, NPCC and NYSRC. The NJCA facilities shall be covered by NERC, RFC and PJM standards and guidelines.

**C. CONTINGENCIES**

All contingencies shall be defined by NERC, NPCC and NYSRC for the NYCA facilities; the NJCA facilities shall be under the NERC, RFC and PJM guidelines.

# III. LOCAL TRANSMISSION SYSTEM

## A. DEFINITION

The local transmission System consists of all electric facilities, which are used to connect the Bulk Power System (BPS), i.e. 345 kV system and the generation system, to the Distribution System. The Transmission System includes all facilities operated at voltages between 34.5 kV and 138 kV and their supply transformers. However, facilities operating at 34.5 kV in the Central and Western Divisions are considered part of the distribution system, with the exception of the Harriman-West Point area system.

The basic functions of the local transmission system are:

(1) To deliver generation from remote sites to load centers while operating within the electrical limitations of existing transmission facilities, and supplying service at the desired time and amounts in a reliable manner;

(2) To accommodate system emergencies including outages of generation or transmission facilities without disruption of service; and,

(3) To dispatch generation from the most economical resources available while maintaining system reliability.

## B. RELIABILITY

### 1. No Loss of Load

The Transmission System will be designed and operated to a level where no loss of load will be allowed during reasonably foreseeable contingencies. Loss of small portions of a system, such as radial portions, will be tolerated provided these do not jeopardize the integrity of the overall transmission system.

**2. Maintenance Outages**

The Transmission System will be designed to allow for maintenance outages. In cases where a substation or customers are supplied from two sources, loss of load will be accepted for reasonably foreseeable contingencies with one supply out for maintenance.

**3. Sufficient Capability**

The Transmission System will be designed with sufficient capability as can be economically justified. Losses will be reduced where possible, optimum economic generation will be provided for and the ability to purchase or sell capacity and energy through various interconnections with other utilities will be maintained.

**4. New Facilities**

New facilities will be designed to provide physical separation so that a single occurrence will not cause simultaneous loss of two supplies to the same distribution substation or load center.

**5. Restoration of Service**

The transfer of load by rearrangement of lines and busses via supervisory control and field switching and readjustment of generator outputs following outages are acceptable means to restore service.

## C. CONTINGENCIES

The Transmission System shall be designed to sustain the following contingencies during all load levels while meeting applicable voltage criteria and limiting equipment loadings to within applicable design ratings:

### 1. Reasonably Foreseeable Single Contingencies

The System will be planned to sustain the following more probable single contingencies without loss of load, except for loss of those customers and substations which solely depend on the outage circuit:

a. Outage of a Single Circuit;
b. Outage of a Transformer;
c. Outage of a Bus Section; and,
d. Outage of a Generator.

During any of the above contingencies, **no facility will be loaded above its long-time emergency (LTE) limits**.

### 2. Double Contingencies

The occurrences of the following specific double contingencies are to be examined for the consequences and possible solutions. However, in no case should they result in a system outage affecting more than 10% of total system peak for a duration greater than four (4) hours.

a. Transmission circuit and transformer within same substation or load area;
b. Generator and either a transformer or a transmission circuit within the same substation or load area;
c. Two transmission circuits on the same structure

d. Two transformers within same substation
e. Two adjacent bus sections.

### 3. Extreme Contingencies

Extreme contingencies are the occurrence of multiple contingency events especially in the BPS that will subject the whole Transmission system to severe conditions. The occurrences of the following extreme contingencies, per NPCC criteria, are to be examined for possible consequences and solutions:

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 a Right of Way (ROW);
d. Permanent three-phase fault on any generator, transmission circuit, transformer, or bus section, which delayed fault clearing and with due regarding to reclosing;
e. The sudden dropping of a large load or major load center;
f. The effect of severe power swings arising from disturbances outside the NPCC's interconnected system; and,
g. Failure of a special protection system, to operate when required following the normal contingencies.

## D. VOLTAGE

The Transmission System shall have supervisory or automatic controls capable of maintaining voltages at levels, which will not exceed limits of the connected equipment during both normal and contingency conditions and will allow for meeting the criteria for customer voltage as defined in the Distribution Planning Criteria.

### A. Operating Range

#### 1.1. Normal Operating Conditions

The voltages on the Transmission System will be maintained within $\pm$ 5% of nominal voltage under normal conditions.

#### 1.2 Single Contingency Operating Conditions

The maximum acceptable voltage deviation during single contingency conditions after LTC transformers have operated is 10%, but not less than 90% or greater than 105% of nominal voltage.

### 2. Reactive Requirements

Capacitors banks are installed in the distribution system for voltage support and loss reduction. On the transmission system, capacitor banks will be installed to provide voltage support during normal operating conditions and post-contingency conditions.

## IV. GENERATING UNIT STABILITY

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

1. A permanent three-phase fault or phase-to-ground fault on any generator transmission circuit, transformer or bus section cleared in normal time;
2. A permanent phase-to-ground fault on any generator transmission circuit, transformer or bus section with delayed clearing.

## V. THERMAL RATINGS

The methodology and criteria used by the Company in rating its transmission line facilities are in accordance with the latest report of the NYPP Task Force on Tie Line Ratings. The Valley Group's Rate Kit Program was utilized to calculate of the thermal ratings for the overhead conductors. For underground cables, EPRI's Underground Transmission Design Tools (UTDT) with ACE Program was used in the computation.

he transformer thermal ratings are derived from the latest version of EPRI's Power Transformer Loading Program (PT LOAD), which is based on the latest version of IEEE's "Guide for Loading Oil-Immersed Distribution and Power Transformer "(IEEE C57.91-1995).

The detailed explanation and additional information of these methods can be found in **Part VII – Thermal Transmission Circuit and Substation Equipment Methodology**.

## VI. SYSTEM FREQUENCY

### A. STANDARD FREQUENCY

The standard frequency on the O & R system is nominally 60 hertz. A sustained frequency excursion of $\pm$0.2 hertz is an indication of a major load-generation unbalance and possible formation of an island. A load shedding program has been developed in order to provide selectivity and flexibility. Most generators are incapable of sustained operation below a specified minimum frequency, typically less than 58.5 hertz.

### B. AUTOMATIC UNDERFREQUENCY LOAD SHEDDING

Underfrequency relays are installed at various locations throughout the system to provide protection against widespread system disturbances. The Underfrequency Load Shedding Program (UFLS) is updated each year for the NYISO and PJM.

## 1. Circuit Weight

A circuit weight is calculated annually for each circuit based on the priority of the customers that are located on the circuit. For example,

(a) A circuit contains a hospital (150), a nursing home (25) and a prison (2) would have a circuit weight of 177.

(b) An artificial weight is given for the two circuits that feed the O & R SVOC building.

The available circuits with underfrequency relays are then prioritized by circuit weight. Excluding circuits with high priority customers, such as hospitals and malls, the UF relays are then turned on for the higher-weighted circuits until the cumulative load for these circuits reaches the requirement for each level. The Underfrequency relays for the remaining circuits are turned off.

## 2. Underfrequency (U/F) relays:

2.1. The **Northeast Power Coordinating Council (NPCC)** requirements are for two frequency settings based on the previous year's peak. The first setting requires 10% of the previous year's peak plus 25% of the curtailables and co-generation used during the previous year's peak to be shed at 59.3 hertz. The second setting requires 15% of the previous year's peak to be shed at 58.8 hertz.

2.2. The **Reliability-First Corporation (RFC)** requirements are for three frequency settings based on forecasted peak. The first setting requires 10% of the year's forecasted peak to be shed at 59.3hertz. The second setting requires 10% of the year's forecasted peak to be shed at 58.9 hertz. The third setting requires 10% of the year's forecasted peak to be shed at 58.5 hertz.

3. **Manual Load Shedding:**

The Manual Load Shed Program is updated every year based on the new circuit weights and the circuits selected for the underfrequency program. Excluding the high priority customers, such as hospitals and malls (public place for heat and air), the circuits that do not have underfrequency relays and the circuits in which the UF relays are turned off are grouped together and prioritized by circuit weight in ascending order. When these circuits are completed, the circuits with underfrequency relays turned on are prioritized by circuit weight in ascending order. Finally, after these circuits are completed, the remaining circuits (high-prioritized circuits) are prioritized by circuit weight in ascending order as well.

## VII. THERMAL TRANSMISSION CIRCUIT AND SUBSTATION EQUIPMENT METHODOLODY

### A. OVERVIEW

It is the responsibility of the Transmission and Substation Engineering Department ("T & S Engineering") to calculate and issue the thermal ratings of O & R's overhead and underground transmission facilities. T & S Engineering shall issue ratings for all O & R transmission facilities operated at nominal voltages of 69 kV or greater; and certain facilities operated below 69 kV including the 34.5 kV system in the Eastern Division operated as distribution system as well as the Harriman-West Point 34.5 kV loop in Central Division.

The purpose of this section is to describe the methodologies used to rate all equipment which may in any way impose loading constraints on transmission circuits, and thus, the ratings are referred to as "thermal ratings." Three thermal ratings will be computed, namely, Normal rating, Long-term Emergency (LTE) rating and Short-time Emergency (STE) rating. However, non-thermal restrictions, such as those imposed by relay settings or design sag limitations, are also recognized and included where appropriate.

The focus of this section is on the capabilities of the transmission circuits, therefore, station equipment not associated with specific transmission circuits will not be included. However, all transmission circuit ratings include the ratings of substation equipment where the equipment terminates and/or limits the specific circuit.

## B. TRANSMISSION CIRCUIT METHODOLOGY AND DERIVATION OF RATINGS

The methodology and criteria used by O & R in rating its transmission facilities are largely derived from latest version of the "Final Report NYPP task Force on Tie Line Ratings (1995)." From the report, the conductor ratings are thermal and the prime consideration in thermal rating determination is that the conductor should not sustain more than ten percent (10%) loss of strength due to annealing over its useful life.

### 1. Thermal Ratings Definition

The operating conditions for which each circuit is rated are defined in the following manner:

#### 1.1 Normal Rating

This refers to the maximum loading that the conductor can carry continuously.

#### 1.2. Long Term Emergency (LTE) Rating

This refers to the maximum loading, which may be carried by a conductor up to four (4) hours following a contingency, totaling not more than 300 hours for the life of the line.

#### 1.3. Short-Time Emergency (STE) Rating

This refers to the maximum loading, which may be carried by a conductor up to fifteen (15) minutes following a contingency totaling not more than twelve and a half (12-½) hours for the life of the line.

## 2. Calculation Assumptions for Overhead Conductors

The Valley Group's Rate Kit 4.1 Program was used in the calculation of the overhead conductors' thermal ratings with the following assumptions:

### 2.1. Maximum Overhead Conductor Temperature

| Conductor Type | SUMMER | | | WINTER | | |
|---|---|---|---|---|---|---|
| | Normal | LTE | STE | Normal | LTE | STE |
| ACSR | 95°C | 115°C | 125°C | 95°C | 115°C | 125°C |
| Copper | 75°C | 100°C | 125°C | 75°C | 100°C | 125°C |
| HTLS* | 180°C | 200°C | 220°C | 180°C | 200°C | 220°C |

**High Temperature Low Sag conductors*

*Table 1*: **Maximum Allowable Overhead Conductor Temperature**

### 2.2. Weather Conditions

The weather provides cooling by means of convective heat loss to the surrounding air. The degree of cooling mainly depends on air temperature, wind speed and wind direction.

***a. Ambient Air Temperature***

The ambient air temperatures for summer and winter operating conditions are 35 °C (95°F) and 10°C (50°F), respectively.

***b. Wind Speed***

The wind speed used is **3 feet per second**.

***c. Wind Direction***

For given wind speed, winds blowing parallel to the conductor result in a 60% lower convective heat loss than winds blowing perpendicular to the conductor. Thermal ratings for bare conductors are traditionally calculated for perpendicular wind even though this is not a conservative assumption. (Perpendicular wind is adopted for the calculations).

## 2.3. Solar Heating

Five data are used solely in calculating the solar heat input to the conductor, namely, Altitude/Latitude, Date, Solar Time, Conductor Orientation and Atmosphere. The conductor's solar absorptivity and emissivity are also used. Elevation above sea level affects both solar heat input and convection heat loss since air density also depends on elevation.

***a*. Elevation above Sea Level**

The solar heat intensity increases with altitude being about 15% higher at 1500 m (5000 ft) than at sea level. (Assumed elevation above sea level is 0 ft).

**b. Latitude (deg)**

Latitude of the line determines both the solar azimuth and solar altitude angles. (Assumed 45 degree Latitude).

**c. Date**

Summer months are June through September while winter months are December through February.

***d. Solar Time***

Solar heating is at its maximum between noon and 3 pm.

*e. Atmosphere*

The solar heating in a heavily polluted air is reduced from 20% to 50% depending on the solar altitude. (Assumed most conductors are in industrial area).

*f. Absorptivity and Emissivity*

Absorptivity and Emissivity factors range from 0.3 to 0.9 depending on the conductor's years of service. For this calculation, a factor of 0.5 was used for both absorptivity and emissivity.

**3. Calculation Assumptions for Underground Cables**

For derivation of the underground cables thermal ratings, EPRI's Underground Transmission Design Tools (UTDT) with ACE Program was used. The ACE program was developed by EPRI to permit users to perform integrated technical and economic analysis of pipe-type, self-contained and extruded dielectric cable systems. The ACE ampacity calculations are based upon the IEC 289 calculation procedures for steady-state calculations, and the IEC-853 approach for transient/emergency calculations. The Neher-McGrath procedure is used to calculate the thermal resistance of the cable to earth ambient temperature.

**3.1 ACE Program Parameters**

The following parameters are utilized in the calculation of the thermal ratings depending on the insulation material used in the cable:

*a. Allowable Conductor Temperature for Different Insulation Materials*

| INSULATION MATERIAL | MAXIMUM TEMPERATURE | |
|---|---|---|
| | NORMAL | EMERGENCY |
| Impregnated Paper<br>AEIC CS2-90 for HPFF and HPGF<br>AEIC CS4-79 for SCLF | <br>85°C<br>75°C | <br>105°C for 100 hr<br>100°C for 300 hr |
| Laminated Paper-Polypropylene<br>AEIC CS2-90 | 85°C<br>75°C | 105°C for 100 hr<br>100°C for 300 hr |
| Cross-linked polyethylene<br>AEIC CS7-87 | 90°C<br>80°C | 130°C<br>Cumulative to 1500 Hrs |
| Ethylene-propylene rubber<br>AEIC CS6-87 | 90°C<br>80°C | 130°C<br>Cumulative to 1500 Hrs |
| Electronegative gas/spacer | Consult manufacturer to specific designs | |

*Table 2:* **Allowable Conductor Temperature for Various Insulation Materials**

*b. Dissipation Factors for Insulation Materials*

| INSULATION MATERIAL | DISSIPATION FACTOR | |
|---|---|---|
| | RANGE | TYPICAL |
| Impregnated Paper | 0.002 – 0.0025 | 0.0023 |
| Laminated Paper-Polypropylene | 0.0007 – 0.0008 | 0.0007 |
| Cross-linked polyethylene | 0.0001 – 0.0003 | 0.0001 |
| Ethylene-propylene rubber | 0.002 – 0.08 | 0.0035 |
| Electronegative gas/spacer | 0+ | 0+ |

*Table 3:* **Dissipation Factors**

*c. Dielectric Constants for Insulation Materials*

| INSULATION MATERIAL | DIELECTRIC CONSTANT | |
|---|---|---|
| | RANGE | TYPICAL |
| Impregnated Paper | 3.3 – 3.7 | 3.5 |
| Laminated Paper-Polypropylene | 2.7 – 2.9 | 2.7 |
| Cross-linked polyethylene | 2.1 – 2.3 | 2.3 |
| Ethylene-propylene rubber | 2.5 – 4.0 | 2.8 |
| Electronegative gas/spacer | 1+ | 1+ |

*Table 4: Dielectric Constants*

*d. Thermal Resistivities of Cable Materials in C° - cm/watt*

| INSULATION MATERIAL | RANGE | TYPICAL |
|---|---|---|
| Impregnated Paper | 500 – 600 | 600 |
| Laminated Paper-Polypropylene | 500 – 600 | 600 |
| Crosslinked polyethylene | 350 – 400 | 350 |
| Ethylene-propylene rubber | 450 – 500 | 450 |
| Somastic | 100 | 100 |
| Transite | 200 | 200 |
| PVC | 400 – 450 | 400 |
| Neoprene | 380 – 580 | 400 |
| Epoxy | 70 – 445 | 100 |
| Thermoplastic Pipe Coating | 350 – 450 | 400 |

*Table 5:* **Thermal Resistivities of Cable Materials**

### 4. Bus and Other Substation Terminal Equipment

The following are the rating factors for other substation terminal equipment:

#### 4.1. Substation Rigid and Strain Bus (Maximum Conductor Temperature)

| Bus Type | SUMMER | | | WINTER | | |
|---|---|---|---|---|---|---|
| | Normal | LTE | STE | Normal | LTE | STE |
| Aluminum | 85°C | 95°C | 105°C | 85°C | 95°C | 105°C |
| ACSR | 95°C | 115°C | 125°C | 95°C | 115°C | 125°C |
| Copper | 75°C | 100°C | 125°C | 75°C | 100°C | 125°C |
| Connections | 85°C | 95°C | 105°C | 85°C | 95°C | 105°C |

*Table 6*: **Substation Bus (Maximum Conductor Temperature)**

### 4.2. Other Substation Terminal Equipment including Circuit Breakers, Line Traps, Current Transformer and Disconnect Switches *(As a percentage of nameplate ratings):*

| Equipment Type | SUMMER | | | WINTER | | |
|---|---|---|---|---|---|---|
| | Normal | LTE | STE | Normal | LTE | STE |
| Circuit Breakers | 104% | 116% | 133% | 122% | 134% | 149% |
| Line Traps | 101% | 111% | 141% | 107% | 118% | 150% |
| Current Transformer | 100% | 128% | 150% | 122% | 148% | 150% |
| Switches 30°C Rise | 108% | 153% | 200% | 141% | 178% | 200% |
| 53°C Rise | 105% | 127% | 160% | 125% | 144% | 174% |

*Table 7*: **Other Substation Terminal Equipment** *(Percentage of Nameplate Rating)*

## C. TRANSFORMER RATINGS METHODOLOGY

### 1. Overview

The methodology and criteria used by O & R in rating its power transformers and distributions substation transformers are derived from EPRI's PT LOAD 6 Program, which was based on the latest version of the IEEE "Guide for Loading Oil – Immersed Distribution and Power Transformers" (IEEE Standard C57.91-1995). Like its earlier versions, the recommendations developed in the IEEE C57.91-1995 used the thermal aging of the winding insulation as the basis for its criteria. The aging of the transformer winding insulation is a major factor in the life expectancy of a transformer, commonly referred to as the "Loss of life" of a transformer.

Transformer life and loading are primarily dependent upon the thermal characteristics of a transformer. Life curves of insulation systems have been established which relate loss of life with the absolute temperature of the insulation (hot spot) and time. The effects of temperature and time are cumulative. The rating factors have been selected so that the total loss of life for the insulation system will be approximately 10% over a 40-year life.

Ambient temperatures have a significant effect on loadability. IEEE Standard C57.91-1995 recommends that the average ambient temperature be used when determining normal ratings and average maximum ambient temperature be used in determining ratings with some loss of life.

PT Load 6 Program utilizes the "Top Oil" Model with various specific test data and physical characteristics as input, and then computes the summer and winter loading capability as a function of loss of life and preloading conditions. Typical input data are enumerated in the succeeding pages.

**2. EPRI'S Power Transformer Loading (PTLOAD 6) Program**

This program implements calculations from IEEE Standard C57.91-1995, "Guide for Loading Mineral-Oil Immersed Transformers," as well as the IEC Standard 354, "Loading Guide for Oil-Immersed Power Transformers." The guide covers general recommendations for loading 65° C rise mineral-oil-immersed power transformers as well as recommendations for the 55° C rise transformers still in the system. PTLOAD 6 calculates transformer temperatures, ratings, loss of insulation life, and gas bubble formation based on user-specified physical parameters for the transformer and user-specified load and air temperature data. Although PTLOAD 6 offers a choice between the conventional "top oil" rating algorithm, based on IEEE Standard C57.91-1995, and the new "bottom oil" rating algorithm also from the same standard, the calculations here were only based on the "top-oil" concept.

**Top Oil**

The "Top Oil' model assumes a linear temperature distribution from the bottom bulk oil to the top bulk oil and a parallel rise in the winding temperatures. These temperatures are assumed to vary as a function of the losses.

**Bottom Oil**

The "Bottom Oil" model is more complex than the top oil model. This model takes into account the faster-rising duct oil-temperatures, as well as a more complex calculation of bottom and top oil temperatures as a function of loss.

**2.1. Input Data**

PTLOAD 6 utilizes operating conditions, specific test data and physical characteristics as input to determine the loading capability of the transformer:

- Coincident load for each distribution substation bank for 24-hour period during the summer peak days.
- Ambient Temperature Cycle over a 24-hour period on the corresponding peak day.
- Assumed 90% preloading.

Typical transformer data consists of the following information from the nameplate or final test reports.

- Top-oil temperature rise over ambient temperature at rated load.
- Average conductor temperature rise over ambient temperature at rated load.
- Winding hot-spot temperature rise over ambient temperature at rated load.
- Load loss at rated load.
- No load (core loss).
- Total loss at rated load.
- Confirmation of oil flow design (that is, directed or non-directed).
- Weight of core and coil assembly.
- Volume of oil in the tank and cooling equipment (excluding LTC compartments, oil expansion tanks, etc.).

**2.2. Transformer Loading**

Applications of loads in excess of nameplate rating involve some degree of risk. While aging and long time mechanical deterioration of winding insulation have been the basis for the loading of transformers, it is now recognized that there are additional factors that may involve greater risk for transformers of higher mega-volt-ampere (MVA) and voltage ratings.

Power transformer life expectancy at various operating temperatures is not accurately known, but the information given regarding loss of insulation life at elevated temperatures is the best that can be produced from present knowledge of the subject. Loads in excess of nameplate rating may subject insulation to temperatures higher than the basis of rating definition. To provide risk associated with higher operating temperature, three (3) basic loadings have been included in this report.

### 2.2.1. Normal Loading

The basic loading of a power transformer for normal life expectancy is continuous loading at rated output when operated under usual conditions. It is assumed that the operation under these conditions is equivalent to operation in an average ambient temperature of 30°C for a cooling air or 25°C for cooling water. Normal life expectancy will result from operating with continuous hottest-spot temperature of 110°C (or equivalent variable temperature with 120°C maximum in any 24-hour period). The 110°C hottest-spot temperature is based on the hottest-spot rise of 80°C plus the standard average ambient temperature of 30°C (105°C for an average ambient of 25°C).

This loading should entail normal winding insulation loss of life for a 24-hour period with a load cycle of 90% preloading or about **0.0133%**. For a 55°C Rise and 65°C Rise transformers, the top oil temperature and hottest-spot temperatures are:

| **Temperatures** | **55°C Rise** | **65°C Rise** |
| --- | --- | --- |
| Top Oil | 95°C | 105°C |
| Hottest-spot | 105°C | 120°C |

*Table 8*: **Normal Loading Top Oil & Hottest Spot Temperatures**

### 2.2.2. Long Term Emergency (LTE) Loading

Long term emergency loading results from the prolonged outage of some system element and causes either the conductor hottest-spot or the top-oil temperature to exceed those suggested for normal loading beyond nameplate rating. This is not normal operating condition, but may persist for some time. It is expected that such occurrences will be rare. This loading assumes a **0.25%** loss of insulation life per occurrence not to exceed 4 hours, also with a 90% preloading. This is equivalent to approximately 19 days loss-of life for the one day in which the emergency occurs.

The LTE top oil temperature and hottest-spot temperatures used in the calculations for 55°C rise and 65°C rise transformers are:

| Temperatures | 55°C Rise | 65°C Rise |
|---|---|---|
| Top Oil | 100°C | 110°C |
| Hottest-spot | 140°C | 140°C |

***Table 9*: LTE Loading Top Oil & Hottest Spot Temperatures**

### 2.2.3. Short Time Emergency (STE) Loading

Short time emergency (STE) loading is unusually heavy loading brought about by the occurrence of one or more unlikely events that seriously disturb normal system loading and cause either the conductor hottest-spot or top-oil temperature to exceed the temperature limits suggested for normal loading beyond nameplate rating. Unlike during long-term emergency, the 0.25% loss of insulation life per occurrence **will not be reached** for this type of loading given the short 15 minutes time period and other limiting criteria.

The top oil temperature and hottest-spot temperatures used in the calculations for 55°C rise and 65°C rise transformers are:

| Temperatures | 55°C Rise | 65°C Rise |
| --- | --- | --- |
| Top Oil | 100°C | 110°C |
| Hottest-spot | 150°C | 150°C |

***Table 10*: STE Loading Top Oil & Hottest Spot Temperatures**

PT LOAD 6's provision for Bubble Avoidance as suggested by the IEEE Standard was not applied in the calculations.

## VIII. INTERCONNECTION PROCEDURES FOR NEW FACILITIES

This Section will cover the interconnection process for integrating new generation, merchant transmission and end-user facility into the transmission system of Orange Rockland Utilities/Rockland Electric Company ("ORU/RECO").

### A. GENERATION FACILITIES

#### 1. NYISO Control Area - Small Generator Interconnection

Interconnection procedures for generation 2 MW but not to exceed 20 MW will follow the general guideline of NYISO's Attachment Z – Small Generator Interconnection Procedures (See www.nyiso.com).

#### 2. NYISO Control Area – Large Generator Interconnection

Large generators are defined a generators exceeding a 20 MW nameplate rating. The interconnection procedures for generation above 20 MW will follow NYISO's Attachment X – Standard Large Facility Interconnection Procedures (See www.nyiso.com).

#### 3. PJM Control Area – Small and Large Generator Interconnection

Small and large generators interconnecting into RECO's transmission system will follow PJM's Manual 14 interconnection procedures (See www.pjm.com).

## B. MERCHANT TRANSMISSION FACILITIES

1. **NYISO Control Area - Merchant Facility Interconnection**

   Interconnection procedures for merchant facilities will follow NYISO's Attachment X – Standard Large Facility Interconnection Procedures (See www.nyiso.com).

2. **PJM Control Area – Merchant Facility Interconnection**

   Merchant facilities interconnecting into RECO's transmission system will follow PJM's Manual 14 interconnection procedures (See www.pjm.com).

## C. END-USER FACILITIES

End-user facilities planning to connect into ORU/RECO's transmission system will follow the procedures of Transmission and Substation Engineering Department's interconnection requirements and procedures.

The specific connection requirements for each of these facilities can be found in the following document:

- Latest version of **ORU-ENGR-005-0** ("Facility Connection Requirements for New Generation, Merchant Transmission and End-User Facilities").

## IX. REFERENCES


1. **Bare Overhead Transmission Conductor Ratings.** Transmission and Substation Design Subcommittee (TSDS). PJM Interconnection, LLC (2000).

2. **Con Edison System - Transmission Design Operating Criteria.** Consolidated Edison Company of New York (2000).

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5. **NYPP Tie-Line Ratings Task Force Final Report**. New York Power Pool (1995).

6. **PT LOAD Version 6.0 User Manual**. Electric Power Research Institute. Power Transformer Loading Program (2002).

7. **Transmission Planning Guidelines.** Orange and Rockland Utilities, Inc. Energy Supply Planning (1991).

8. **Underground Transmission Systems.** Electric Power Research Institute. Jay A. Williams and Anthony Ernst. (1992).

9. **NYISO Attachment X – Standard Large Facility Interconnection Procedures**

10. **NYISO Attachment Z – Small Generator Interconnection Procedures**

11. **PJM's Manual 14 – Generation and Transmission Interconnection Process**

12. **ORU-ENGR-005-0** (Facility Connection Requirements for New Generation, Merchant Transmission and End-User Facilities)