The Narragansett Electric Company

d/b/a National Grid (Rhode Island Reliability Project)

RIPUC Dkt. No. 4029

Testimony of

Mark Stevens, P.E.

February 20, 2009

INTRODUCTION

Q. Please state your name and business address.

A. My name is Mark Stevens. My business address is 25 Research Drive, Westborough, Massachusetts 01582.

Q. By whom are you employed and in what position?

A. I am employed as a Lead Senior Engineer by National Grid USA Service Company in the Transmission Planning Department.

Q. What are your responsibilities in that position?

A. I am responsible for transmission system planning for National Grid in its New England service territory. Transmission System Planning includes determination of need for reinforcement of the transmission supply system, evaluation of alternative solutions, and selection of the most satisfactory solution.

Q. Please describe your education, training and experience.

A. I am a graduate of University of Vermont, holding a Bachelor of Science degree in Electrical Engineering; I am also a graduate of Northeastern University, holding a Master of Science degree in Electrical Engineering. I have five years of experience in power system planning and analysis. I have been a Lead Senior Engineer in the Transmission Planning Department since July of 2007; prior to that I was a Senior Engineer in the department since October of 2003. During this time, I have been responsible for many transmission planning studies including the NEEWS study. From September 1995 up to October 2003, I was employed as an electrical engineer in the

Energy Management System group in the Dispatching Department at National Grid. I am also a Registered Professional Engineer in the Commonwealth of Massachusetts.

Q. Are you familiar with Narragansett Electric's Rhode Island Reliability Project?

A. Yes, I am. I conducted National Grid's portion of the NEEWS study of which the Rhode Island Reliability Project is a part. The study is documented in two reports published by ISO New England Inc. "Southern New England Transmission Reliability Report 1, Needs Analysis" (January 2008) and "New England East-West Solutions Report 2, Options Analysis" (June 2008) (collectively the "Study Reports".) They are included as Appendices D and E to the Environmental Report ("ER").

Q. Are you familiar with National Grid's Energy Facility Siting Board Application, including the ER prepared by VHB for the Project?

A. Yes, I prepared the analysis of the need for the Project in the ER.

Q. What is the Rhode Island Reliability Project?

A. The Rhode Island Reliability Project (the "Project") is a reinforcement of the bulk transmission system in Rhode Island to alleviate overloaded lines and equipment and to address voltage violations. The major component of the Project is a new 345 kV transmission line from the West Farnum Substation to the Kent County Substation. The Project is a solution to one of the five problems identified in the New England East-West Solutions (NEEWS) Planning studies. These studies were conducted by a working group comprised of representatives of ISO-NE, National Grid and Northeast Utilities. I was the National Grid representative on the working group. The NEEWS Study was one of the most geographically comprehensive planning efforts to-date in New England, addressing five interrelated problems in three states and multiple service territories. The analysis was aimed at addressing the weaknesses of the transmission system in southern New England. NEEWS will benefit all of the New England states by addressing the issues of regional transmission system reliability and constrained generation.

Q. What is the scope of your testimony in this proceeding?

A. In my testimony, I will summarize the planning process by which National Grid identifies a need for transmission system improvements, describe the transmission planning study which I conducted and address several alternatives which were examined as part of the process. A more detailed description is contained in Chapter 3.0 of the ER and in the Study Reports. I will also address how the need for the Project has been impacted by changes in the market and load forecast that have occurred since the original studies were completed.

Q. Please describe the process by which National Grid determines that transmission system improvements are necessary.

A. The process by which National Grid determines that transmission system improvements are necessary is described in detail in Sections 3.1 and 3.2 of the ER. In general, transmission planning studies are undertaken to analyze system performance and determine whether upgrades to existing facilities or additional facilities might be needed to maintain the reliability of the electric transmission system. The reliability standards for the National Grid transmission system are described in the National Grid Transmission Planning Guide (Attachment MS-1 to this testimony), the ISO-NE Planning procedures, the Northeast Power Coordinating Council (“NPCC”) criteria, and the North American Electric Reliability Corporation ("NERC") standards. These standards require that National Grid's transmission system be designed so that facility loadings (the amount of power being carried by the facility) are kept within capabilities of the transmission equipment. They further require that the transmission system operate within an acceptable range of voltages. These requirements must be satisfied under normal conditions, as well as under foreseeable contingencies such as the loss of a major transmission line. To ensure that the transmission system continues to meet these reliability criteria, electrical system studies are conducted for an area for a given period of time, commonly looking out 10 to 15 years. The studies are conducted using computer simulations of the transmission system. Normal conditions and various contingency conditions are simulated. The flow and voltage levels on the transmission lines and substation equipment are monitored and checked to confirm that the flows and voltage levels remained within the capability of the equipment. The flow capabilities (ratings) are determined based on the maximum allowable component temperatures. The temperatures are fixed by manufacturers' design, American National Standards Institute (ANSI) standards, known material properties, or, in the case of a transmission line, the design of the line. The range of allowable equipment voltage is set by manufacturers' design and ANSI standard. In cases where the simulations indicate that loading or voltage on a facility exceeds its capabilities, changes to the facility or the system that will allow the facility to remain within its capabilities are evaluated.

Q. Did you analyze the Rhode Island electric transmission system?

A. Yes I did.

Q. What were the results of your analysis of the transmission system?

My analysis identified a series of transmission reliability concerns which require attention.

Q. Please describe the transmission reliability concerns.

A. The reliability problems on the Rhode Island 115 kV system are caused by a number of contributing factors (both independently and in combination), including high load growth (especially in southern Rhode Island and the coastal communities), possible generation unit unavailability, and transmission outages (planned or unplanned). Additionally, the Rhode Island 115 kV system is constrained when one of the Rhode Island 345 kV lines is out of service.

An outage of any of these 345 kV transmission lines results in limits to power transfer into the Rhode Island 115 kV transmission system. For line-out conditions, the next critical contingency would involve the loss of a second 345 kV line or a critical 115 kV line or the loss of a 345/115 kV autotransformer.

The most severe dispatch and contingency conditions (without the Rhode Island Reliability Project in service) are shown in Table 3-1 of the ER. This table is attached to my testimony as Attachment MS-2. Some of the conditions described in the table result in major blackouts over a wide area. There are many other dispatch and contingency conditions that result in "lesser" criteria violations that are not included in the table.

Q. Please describe how the need for the Project has been impacted by changes in the market and load forecast that have occurred since the original studies were completed.

A. The following table and discussion describes the impact.

	New England Load	**State of Rhode Island Load (6.5% of NE load)**	**Load Pocket (47% of RI load)**
Load level at which Needs Analysis was performed	32,648 MW	2,137 MW	1009 MW
Adjustment for ISO-NE 2008 CELT 2014 90/10 peak load forecast	+127 MW	+8 MW	+4 MW
DSM from FCA #2	-1521 MW	-76 MW	-36 MW
Adjustment due to Ridgewood Generator on S-171S line (cleared in FCA #2)			-34 MW
Adjustment due to early prediction of 2009 forecast	-530 MW	- 34 MW	-16 MW
Total Net Adjustment			**-82 MW**

Note: All load levels in the table represent both load and losses.

For this table the "Load Pocket" column represents the Rhode Island load that is located electrically south of the Hartford Avenue 115 kV substation. This is the load that primarily drives the need for the Project. The "Total Net Adjustment" of 82 MW (from the above table) is the amount that the load within the Load Pocket would be reduced based on the latest load predictions and the latest Forward Capacity Auction. Table 3-1 (Worst Rhode Island Criteria Violations) in the Purpose and Needs section of the ER identifies the amount of load shedding that is required under various contingencies to prevent widespread blackouts and/or overloads. This table shows load shedding requirements in the 100 MW to more than 500 MW range. Reducing the load in the "load pocket" by 82 MW would not be enough to alleviate any of the worst Rhode Island criteria violations listed in Table 3-1. The 82 MW reduction is less than the smallest required mitigation load shedding of 100 MW) and significantly less than the 500 MW reduction required under the most severe contingencies. Therefore, the latest load predictions and the results of the latest Forward Capacity Auction do not significantly reduce the need for the Rhode Island Reliability Project.

Alternatives

Q. Please describe the alternatives considered in the Study Reports.

A. Three transmission alternative solutions, including the proposed solution, were studied to address the problems. The key elements of these alternatives were as follows:

- A new 345 kV transmission line from the West Farnum Substation to the Kent County Substation (the proposed solution.)
- New 345 kV transmission line from Brayton Point Substation to Kent County Substation.
- Two new 115 kV underground transmission lines from Franklin Square Substation to Sockanosset Substation.

Q. Please describe the proposed solution.

A. National Grid is proposing to construct a new 21.4 mile 345 kV transmission line (359 Line) on an existing right-of-way ("ROW") between the West Farnum Substation located on Greenville Road in North Smithfield, and the Kent County Substation located on Cowesett Road in Warwick.

The existing ROW presently contains one 345 kV transmission line (332 Line), two 115 kV transmission lines (S-171 and T-172 Lines) and, in places, 23 kV sub-transmission lines. In order to create adequate space within this existing ROW corridor to enable the construction of the proposed 345 kV transmission line, National Grid proposes to relocate and reconstruct the existing S-171 and T-172 115 kV transmission lines on more compact vertically configured structures.

National Grid is also proposing to install one new 345 kV autotransformer and other equipment at the Kent County Substation to accommodate the new 345 kV transmission line. Similarly, equipment additions at the West Farnum Substation in North Smithfield are proposed to integrate the new 345 kV line into the transmission network.

Lastly, National Grid proposes to reconductor portions of three 115 kV transmission lines to alleviate potential overloads on these transmission lines. The S-171S and T-172S 115 kV transmission lines will be reconductored from the Hartford Avenue Substation to the Johnston Taps coincident with the overall reconstruction of the lines. The G-185N 115 kV transmission line from Drumrock Substation to Kent County Substation will also be reconductored.

Q. Please describe the alternative that includes a new 345 kV line from Brayton Point to the Kent County Substation.

A. This electrical alternative was a part of a larger NEEWS option; the full 345-kV portion of this NEEWS option was a 345 kV line connecting Montville Substation to Kent County Substation to Hartford Avenue Substation to Franklin Square Substation to Brayton Point Substation. This option attempted to resolve some the transmission bottlenecks by interconnecting the three Greater Rhode Island substations of Brayton Point, Hartford Avenue (which would be a new 345-kV substation), and Kent County. This alternative included the following components:

- Build a new 345 kV line from Brayton Point to Franklin Square Substation to Hartford Avenue Substation to Kent County Substation (about 30 miles.) As part of this, the existing 115 kV E105 and F106 cables from Franklin Square to Hartford Avenue would be converted into a single 345 kV cable.

- Install an additional 345/115 kV transformer at Kent County Substation.

- The 115 kV W4/K15 and X3 lines would be removed, and Swansea Substation would be moved to the E183E line to make space available for the new 345-kV line.

- All of the Phillipsdale substation would be fed from E-183W (since the other supply line to Phillipsdale, the X3, would be removed).

Analysis showed that this NEEWS option tended to push far too much power from Brayton Point to West Farnum and Kent County load area and thus heavily overloaded 345/115 kV transformers and 115 kV transmission system elements in western Rhode Island. The following are some of the details.

For N-1 contingency conditions and a critical 115 kV generator offline:

- This alternative overloads the autotransformers and 115 kV equipment at West Farnum and Kent County for various contingencies (this is at least partially due to the conversion of E105 and F106 cables to 345 kV - which eliminates two 115 kV supply lines to the load area).

- For loss of the E-183E 115 kV line, the transmission system voltage collapses (most likely due to low 115 kV voltages in the Providence area).

For N-1-1 contingency conditions and a critical 115 kV generator offline:

- With Brayton Point 3T 345/115 kV transformer out of service - heavy overloads of Kent County and West Farnum autotransformers and 115 kV equipment occur for various contingencies.

- With West Farnum T174 345/115 kV transformer out of service - heavy overloads of Kent County autotransformers and 115 kV equipment occur for various contingencies.

- With the 328 line out of service - heavy overloads of Kent County autotransformers and 115 kV equipment occur for various contingencies.

- With 336 or 303 or 315 lines out of service - heavy overloads of Kent County and West Farnum autotransformers and 115 kV equipment occur for various contingencies.

- With Kent County 345/115 kV transformers out of service - heavy overloads of Kent County and West Farnum autotransformers and 115 kV equipment occur for various contingencies.

Q. Would it be possible to reduce these overloads?

A. Yes. The following are additional upgrades which were identified in order to reduce some but not all of the contingency overloads:

- Install a 345/115 kV autotransformer at Franklin Square
- Install a 345/115 kV autotransformer at Hartford Avenue
- Build a second 345 kV line from Sherman Road to West Farnum
- Build a second 345 kV line from West Farnum to Millbury or Sherman Road to Millbury.

However, even with these additional upgrades, there would still be significant second contingency autotransformer and 115 kV line overloads, so further upgrades would need to be identified. Clearly this alternative becomes impractical and unrealistic due to the large number and scale of new facilities required. Therefore, this alternative was not pursued further.

Q. Please describe the alternative that includes two new 115 kV underground transmission lines from Franklin Square Substation to Sockanosset Substation.

A. The alternative of building two 115 kV underground transmission lines from Franklin Square Substation to Sockanosset Substation would include the following components:

- Install two 115 kV underground cables 4.5 miles from Franklin Square Substation to a new underground to overhead transition station near the existing Auburn distribution substation. From the transition station, install 1 mile of two 115 kV overhead transmission lines to Sockanosset Substation, connecting into the existing I-187 and J-188 115 kV overhead lines that originate at the Drumrock Substation.

- Expand and upgrade Franklin Square and Sockanosset 115 kV substations in order to accommodate the new lines.

This alternative is only a partial solution in that it would only seek to replace the proposed 345 kV line from West Farnum to Kent County with a 115 kV connection. Under this alternative, all of the other parts of the Rhode Island Reliability Project would still be required. The Franklin Square to Sockanosset underground/overhead 115 kV system would serve to strengthen the 115 kV transmission system by providing an additional connection from the Providence area to southern Rhode Island. This alternative does not perform adequately under N-1-1 (line-out) system conditions. When the existing 345 kV line from West Farnum to Kent County (Line 332) is out of service and a critical 115 kV generator is offline, various second contingencies (N-1-1) cause significant 345/115 kV transformer and 115 kV line overloads, and would require additional upgrades to eliminate these overloads.

Q. What additional upgrades and modifications would be needed?

A. In examining what additional upgrades and modifications would be needed, consideration was given to converting the existing E-105 and F-106 115 kV underground cables (Franklin Square to Hartford Avenue) to a single 345 kV circuit. However, if this were done, there would be significantly increased overloads and voltage violations on the Rhode Island transmission system as compared to the transmission system with these cables remaining as two 115 kV circuits. Therefore the conversion of the E-105 and F-106 115 kV underground cables (Franklin Square to Hartford Avenue) to a single 345 kV circuit was not pursued further.

Additional system upgrades were examined to address the identified shortcomings of the Franklin Square Substation to Sockanosset Substation 115 kV interconnection. The following are the additional upgrades that were found to be needed in order to eliminate contingency overloads:

- Install a third 345/115 kV autotransformer at West Farnum.
- Reconductor (and probably rebuild) the 115 kV E-183 line from Brayton Point to Mink Street (12 miles) and upgrade associated terminal equipment. This line is currently built with 2-1113 bundled conductor wires. This wire size is already larger than National Grid's standard conductor size for 115 kV lines. Further increasing the conductor size to allow greater flow on the circuit would lead to large reactive losses which are characteristic of a "weak" circuit and which could lead to voltage problems as load continues to grow.
- Reconductor and rebuild the 115 kV West Farnum S-171N and T-172N tap lines with large bundled conductors.
- Reconductor portions of the 115 kV S-171N and T-172N lines.
- Reconductor the 115 kV I-187 and J-188 lines from Sockanosset to Lincoln and Lincoln to Pontiac.

With the two new Franklin Square to Sockanosset 115 kV cables and the additional upgrades listed above, when the 345 kV 332 line is out of service and one of the Franklin Square to Sockanosset cables is subsequently lost, the remaining Franklin Square to Sockanosset cable could be loaded to 87% of its 12 hour Long Term Emergency ("LTE") limit during the summer of its in-service year. At 87%, this cable would be loaded higher than the maximum loading that is the planning practice for a newly proposed facility. The National Grid planning practice is to have no more than

80% loading on a new project. If this were a simple upgrade that bought some time before a more permanent solution would be implemented, 87% may be acceptable, but the installation of two new 115 kV underground transmission lines (along with all of the other additional upgrades required) would definitely constitute a major project. This means that the lifetime of this solution would be very limited as the load continued to grow. Therefore in order to legitimately make this alternative a viable longer term solution, one of the following further upgrades would be required:

- Install either larger underground cables or install two underground cables per circuit for the new Franklin Square to Sockanosset circuits. This would have the detrimental effect of further increasing loading on the E-183 line and may require reconductoring more sections of the I-187 and J-188 115 kV lines. It may also require shunt reactors to mitigate possible high voltages due to the large amount of underground cables.

- Install a third 115 kV underground circuit between Franklin Square and Sockanosset. This would have the detrimental effect of further increasing loading on the E-183 line and may require reconductoring more sections of the I-187 and J-188 115 kV lines and may also require shunt reactors to mitigate possible high voltages due to the large amount of underground cables.

Q. Do you consider this alternative to be an acceptable alternate to the proposed Project?

A. No. Even with all of these additional upgrades, this alternative is not on par with the proposed plan. It is essentially a shorter term, stop-gap type of solution. It does not provide the future capacity, flexibility, or expandability, that the proposed plan does, and it does not provide strong bulk transmission access and support to this heavily loaded area. Therefore, this alternative was not further pursued.

Q. Do you consider either alternative to be an acceptable solution?

A. After examining the three electrical alternatives, it was determined that only the proposed alternative that includes a new 345 kV line between West Farnum and Kent County fully addressed the needs and reliability concerns of the Rhode Island area transmission system in a reasonable fashion.

Q. What are the consequences of pursuing the "No-Build" option?

A. As described in an answer to an earlier question, the proposed transmission system improvements are required to satisfy the transmission planning criteria of National Grid, the ISO-NE and NEPOOL, NPCC, and NERC. Due to existing and projected electricity demand levels in the Rhode Island area and existing system limitations, these planning criteria require that the proposed transmission system improvements be completed in a timely manner to provide reliable electric supply to the area. Additionally, planning analysis has shown that contingency failures could lead to overloading of facilities throughout Rhode Island. Such an event could cause damage to conductors and equipment, excessive sagging of conductors creating a safety risk due to reduced clearances, and low voltage conditions leading to possible voltage collapse and black-outs. The No-Build alternative would mean that National Grid would be unable to meet the identified system needs and therefore is not an acceptable alternative.

Q. Please describe the non-transmission alternatives analysis.

A. The non-transmission alternative analysis was performed by ICF International for National Grid and is described in detail in the report "Assessment of Non-Transmission Alternatives to the NEEWS Transmission Projects: Rhode Island Reliability Project" and in the prefiled testimony of Kenneth Collison from ICF. To perform the analysis of the effect of non-transmission alternatives on the Rhode Island Reliability Project, ICF has considered the addition of demand resources (including distributed generation), traditional generation supply, and combined heat and power supply options and examined the impact of a large total combined penetration of these resources on the overall reliability of the area as determined through power-flow modeling analysis at peak conditions for pre- and post-Rhode Island Reliability Project cases.

Based on the results of the analysis performed for this study that included projected new generation, DSM, and CHP resources, the Rhode Island Reliability Project was determined to be critical to the reliable operation of the New England transmission grid, and in particular, the Rhode Island transmission system. Non-transmission alternatives to the Rhode Island Reliability Project were found not to be satisfactory or sufficient in nature to displace or defer the need for the Project. This conclusion is supported by results of the power-flow analysis which indicate that, despite the addition of generation, DSM, and CHP resources previously described, numerous transmission facility overloads and substation voltage violations could still potentially occur under contingency conditions.

Q. What is the conclusion of your analysis?

A. After examining the transmission and non-transmission alternatives, it was determined that only the proposed alternative of a new 345 kV line between the West Farnum and Kent County Substations (along with the other components that are part of the proposed alternative) fully addressed the needs and reliability concerns of the Rhode Island area transmission system.

Q. Does this complete your testimony?

A. Yes, it does.

ATTACHMENTS

MS-1	National Grid Transmission Planning Guide
MS-2	Table 3-1 of the ER

United States Operations

Transmission Group Procedure

TGP28

Transmission Planning Guide

Authorized by

Date:

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TABLE OF CONTENTS

1.0 Change Control

Version	Date	Modification	Author(s)	Reviews and Approvals by
Issue 1	06 August 2007	Initial Document	Philip J. Tatro	David Wright
Issue 2	29 February 200~~7~~8	Removed "Confidential" from page header	Philip J. Tatro	David Wright

2.0 Introduction

2.1 Objective of the Transmission Planning Guide

The objective of the Transmission Planning Guide is to define the criteria and standards used to assess the reliability of the existing and future National Grid transmission system for reasonably anticipated operating conditions and to provide guidance, with consideration of public safety and safety of operations and personnel, in the design of future modifications or upgrades to the transmission system. The guide is a design tool and is not intended to address unusual or unanticipated operating conditions. This Planning Guide is applicable to all National Grid facilities operated at 69 kV and above.

2.2 Planning and Design Criteria

All National Grid facilities that are part of the bulk power system and part of the interconnected National Grid system shall be designed in accordance with the latest versions of the NERC Reliability Standards, Northeast Power Coordinating Council (NPCC) Criteria, ISO-New England Reliability Standards, New York State Reliability Council (NYSRC) Reliability Rules, and the National Grid Design Criteria. The fundamental guiding documents are:

- NERC Reliability Standards TPL-001, *System Performance Under Normal Conditions*, TPL-002, *System Performance Following Loss of a Single BES Element*, TPL-003, *System Performance Following Loss of Two or More BES Elements*, and TPL-004, *System Performance Following Extreme BES Events*,
- NPCC *Basic Criteria for Design and Operation of Interconnected Power Systems* (NPCC Document A-2) and *Bulk Power System Protection Criteria* (NPCC Document A-5),
- *Reliability Standards for the New England Area Bulk Power Supply System* (ISO-NE Planning Procedure No. 3),
- *New York State Reliability Council Reliability Rules for Planning and Operation of the New York State Power System*, and
- National Grid Transmission Planning Guide (this document).

Interconnections of new generators to the National Grid transmission system in New England shall be configured and designed in compliance with the ISO-New England document, "General Transmission System Design Requirements for the Interconnection of New Generators (Resources) to the Administered Transmission System." If corresponding New York ISO requirements are established, interconnections to the National Grid transmission system in New York will be configured and designed in compliance with those requirements.

All National Grid facilities that are not part of the bulk power system, but are part of the interconnected National Grid system shall be designed in accordance with the latest version of this document.

All National Grid or National Grid transmission customers' facilities which are served by transmission providers other than National Grid shall be designed in accordance with the planning and design criteria of the transmission supplier and the applicable NERC, NPCC, ISO-NE, and NYSRC documents.

Detailed design of facilities may require additional guidance from industry or other technical standards which are not addressed by any of the documents referenced in this guide.

2.3 Operational Considerations in Planning and Design

The system should be planned and designed with consideration for ease of operation. Such considerations include, but are not limited to:

- utilization of standard components to facilitate availability of spare parts
- optimization of post contingency switching operations
- reduction of operational risks
- judicious use of Special Protection Systems (SPSs)

3.0 System Studies

3.1 Basic Types of Studies

The basic types of studies conducted to assess conformance with the criteria and standards stated in this guide include but are not limited to Powerflow, Stability, Short Circuit, and Protection Coordination.

3.2 Study Horizon

The lead time required to plan, permit, license, and construct transmission system upgrades is typically between one and ten years depending on the complexity of the project. As a result, investments in the transmission system should be evaluated for different planning horizons in the one to ten-year range. The typical horizons are referred to as near term (one to three years), mid-term (three to six years), and long term (six to ten years). The long term time frame may be extended for development of long term transmission infrastructure planning, to aid in development of long term expansion plans, and to assess the adequacy of proposed facilities beyond the ten year horizon. Projects taking less than a year to implement tend to consist of non-construction alternatives that are addressed by operating studies.

3.3 Future Facilities

Planned facilities should not automatically be assumed to be in-service during study periods after the planned in-service date. Sensitivity analysis should be performed to identify interdependencies of the planned facilities. These interdependencies should be clearly identified in the results and recommendations.

3.4 Equipment Thermal Ratings

Thermal ratings of each load carrying element in the system are determined such that maximum use can be made of the equipment without damage or undue loss of equipment life. The thermal ratings of each transmission circuit reflect the most limiting series elements within the circuit. The existing rating procedures are based on guidance provided by the NEPOOL System Design Task Force (SDTF), the NYPP Task Force on Tie Line Ratings, and industry standards. A common rating procedure has been developed for rating National Grid facilities in New England and New York which will be applied to all new and modified facilities. The principal variables used to derive the ratings include specific equipment design, season, ambient conditions, maximum allowable equipment operating temperatures as a function of time, and physical parameters of the equipment. Procedures for calculating the thermal ratings are subject to change.

Equipment ratings are summarized in the following table by durations of allowable loadings for three types of facilities. Where applicable, actions that must be taken to relieve equipment loadings within the specified time period also are included.

Equipment	RATINGS			
	Normal	Long Time Emergency (LTE)	Short Time Emergency (STE)	Drastic Action Limit (DAL)[4]
Overhead Transmission	Continuous	Loading must be reduced below the Normal rating within 4 hours[2]	Loading must be reduced below the LTE rating within 15 minutes	requires immediate action to reduce loading below the LTE rating
Underground Cables[1]	Continuous	Loading must be reduced below the 100 hr or 300 hr rating within 4 hours[2]	Loading must be reduced below the 100 hr or 300 hr rating within 15 minutes	requires immediate action to reduce loading below the LTE rating
Transmission Transformers	Continuous	Loading must be reduced below the Normal rating within 4 hours[2]	Loading must be reduced below the LTE rating within 15 minutes[3]	requires immediate action to reduce loading below the LTE rating

[1] Ratings for other durations may be calculated and utilized for specific conditions on a case-by-case basis. Following expiration of the 100 hr or 300 hr period, loading of the cable must be reduced below the Normal rating. Either the 100 hr or the 300 hr rating may be utilized after the transient period, but not both. If the 100 hr rating is utilized, the loading must be reduced below the Normal rating within 100 hr, and the 300 hr rating may not be used.

[2] The summer LTE rating duration is 12 hours in New England. The winter LTE rating duration in New England, and the summer and winter LTE rating duration in New York is 4 hours. The time duration does not affect the calculated value of the LTE rating. The duration difference reflects how the LTE ratings are applied by the ISO in each Area.

[3] The transformer STE rating is based on a 30 minute duration to provide additional conservatism, but is applied in operations as a 15 minute rating.

[4] The DAL rating is only calculated only in New England based on historical ISO requirements.

3.4.1 Other Equipment

Industry standards and input from task forces in New England and New York should continue to be used as sources of guidance for developing procedures for rating new types of equipment or for improving the procedures for rating the existing equipment.

3.4.2 High Voltage DC

High Voltage dc (HVdc) equipment is rated using the manufacturer's claimed capability.

3.5 Modeling for Powerflow Studies

The representation for powerflow studies should include models of transmission lines, transformers, generators, reactive sources, and any other equipment which can affect power flow or voltage. The representation for fixed-tap, load-tap-changing, and phase shifting transformers should include voltage or angle taps, tap ranges, and voltage or power flow control points. The representation for generators should include reactive capability ranges and voltage control points. Equipment ratings should be modeled for each of these facilities including related station equipment such as buses, circuit breakers and switches. Study specific issues that need to be addressed are discussed below.

3.5.1 Forecasted Load

The forecasted summer and winter peak active and reactive loads should be obtained annually from the Transmission Customers for a period of ten or more years starting with the highest actual seasonal peak loads within the last three years. The forecast should have sufficient detail to distribute the active and reactive coincident loads (coincident with the Customers' total peak load) across the Customers' Points of Delivery. Customer owned generation should be modeled explicitly when the size is significant compared to the load at the same delivery point, or when the size is large enough to impact system dynamic performance.

The Point of Delivery for powerflow modeling purposes may be different than the point of delivery for billing purposes. Consequently, these points need to be coordinated between National Grid and the Transmission Customer.

To address forecast uncertainty, the peak load forecast should include forecasts based on normal and extreme weather. The normal weather forecast has a 50 percent probability of being exceeded and the extreme weather forecast has a 10 percent probability of being exceeded. Due to the lead time required to construct new facilities, planning should be based conservatively on the extreme weather forecast.

3.5.2 Load Levels

To evaluate the sensitivity to daily and seasonal load cycles, many studies require modeling several load levels. The most common load levels studied are peak (100% of the extreme weather peak load forecast), intermediate (70 to 80% of the peak), and light (45 to 55% of the peak). The basis can be either the summer or winter peak forecast. In some areas, both seasons may have to be studied.

Sensitivity to the magnitude of the load assumptions must be evaluated with the assumed generation dispatch to assess the impact of different interactions on transmission circuit loadings and system voltage responses.

3.5.3 Load Balance and Harmonics

Balanced three-phase 60 Hz ac loads are assumed at each Point of Delivery unless a customer specifies otherwise, or if there is information available to confirm the load is not balanced. Balanced loads are assumed to have the following characteristics:

- The active and reactive load of any phase is within 90% to 110% of the load on both of the other phases
- The voltage unbalance between the phases measured phase-to-phase is 3% or less
- The negative phase sequence current (RMS) in any generator is less than the limits defined by the current version of ANSI C50.13

Harmonic voltage and current distortion is required to be within limits recommended by the current version of IEEE Std. 519.

If a customer load is unbalanced or exceeds harmonic limits, then special conditions not addressed in this guide may apply.

3.5.4 Load Power Factor

Load Power Factor for each delivery point is established by the active and reactive load forecast supplied by the customer in accordance with Section 3.5.1. The reactive load may be adjusted as necessary to reflect load power factor observed via the Energy Management System (EMS) or metered data. The Load Power Factor in each area in New England should be consistent with the limits set forth in Operating Procedure 17 (OP17).

3.5.5 Reactive Compensation

Reactive compensation should be modeled as it is designed to operate on the transmission system and, when provided, on the low voltage side of the supply transformers. Reactive compensation on the feeder circuits is assumed to be netted with the load. National Grid should have the data on file, as provided by the generator owners, to model the generator reactive capability as a function of generator active power output for each generator connected to the transmission system.

3.5.6 Generation Dispatch

Analysis of generation sensitivity is necessary to model the variations in dispatch that routinely occur at each load level. The intent is to bias the generation dispatch such that the transfers over select portions of the transmission system are stressed pre-contingency as much as reasonably possible. An exception is hydro generation that should account for seasonal variation in the availability of water.

A merit based generation dispatch should be used as a starting point from which to stress transfers. A merit based dispatch can be approximated based on available information such as fuel type and historical information regarding unit commitment. Interface limits can be used as a reference for stressing the transmission system. Dispatching to the interface limits may stress the transmission system in excess of transfer levels that are considered normal.

3.5.7 Facility Status

The initial conditions assume all existing facilities normally connected to the transmission system are in service and operating as designed or expected. Future facilities should be treated as discussed in Section 3.3.

3.6 Modeling For Stability Studies

3.6.1 Dynamic Models

Dynamic models are required for generators and associated equipment, HVdc terminals, SVCs, other Flexible AC Transmission Systems (FACTS), and protective relays to calculate the fast acting electrical and mechanical dynamics of the power system. Dynamic model data is maintained as required by NERC, NPCC, ISO-NE, and NYSRC.

3.6.2 Load Level and Load Models

The load levels studied in stability studies vary between New England and New York consistent with accepted practices in each Area. Stability studies within New England typically exhibit the most severe system response under light load conditions.

Consequently, transient stability studies are typically performed for several unit dispatches at a system load level of 45% of peak system load. At least one unit dispatch at 100% of system peak load is also analyzed. Other system load levels may be studied when required to stress a system interface, or to capture the response to a particular generation dispatch.

Stability studies within New York typically exhibit the most severe system response under summer peak load conditions. Consequently, transient stability studies are typically performed with a system load level of 100% of summer peak system load. Other system load levels may be studied when required to stress a system interface, or to capture the response to a particular generation dispatch.

System loads within New England and New York are usually modeled as constant admittances for both active and reactive power. These models have been found to be appropriate for studies of rotor angle stability and are considered to provide conservative results. Other load models are utilized where appropriate such as when analyzing the underfrequency performance of an islanded portion of the system, or when analyzing voltage performance of a local portion of a system.

Loads outside NEPOOL are modeled consistent with the practices of the individual Areas and regions. Appropriate load models for other Areas and regions are available through NPCC.

3.6.3 Generation Dispatch

Generation dispatch for stability studies typically differs from the dispatch used in thermal and voltage analysis. Generation within the area of interest (generation behind a transmission interface or generation at an individual plant) is dispatched at full output within known system constraints. Remaining generation is dispatched to approximate a merit based dispatch. To minimize system inertia, generators are dispatched fully loaded to the extent possible while respecting system reserve requirements.

3.7 Modeling for Short Circuit Studies

Short Circuit studies are performed to determine the maximum fault duty on circuit breakers and other equipment and to determine appropriate fault impedances for modeling unbalanced faults in transient stability studies.

Short Circuit studies for calculating maximum fault duty assume all generators are on line, and all transmission system facilities are in service and operating as designed.

Short Circuit studies for determining impedances for modeling unbalanced faults in stability studies typically assume all generators are on line. Switching sequences associated with the contingency may be accounted for in the calculation.

3.8 Modeling for Protection Studies

Conceptual protection system design should be performed to ensure adequate fault detection and clearing can be coordinated for the proposed transmission system configuration in accordance with the National Grid protection philosophy and where applicable, with the NPCC "Bulk Power System Protection Criteria". Preliminary relay settings should be calculated based on information obtained from powerflow, stability, and short circuit studies to ensure feasibility of the conceptual design.

When an increase in the thermal rating of main circuit equipment is required, a review of associated protection equipment is necessary to ensure that the desired rating is achieved. The thermal rating of CT secondary equipment must be verified to be greater than the required rating. Also, it is necessary to verify that existing or proposed protective relay trip settings do not restrict loading of the protected element and other series connected elements to a level below the required circuit rating.

3.9 Development and Evaluation of Alternatives

If the projected performance or reliability of the system does not conform to the applicable planning criteria, then alternative solutions based on safety, performance, reliability, environmental impacts, and economics need to be developed and evaluated. The evaluation of alternatives leads to a recommendation that is summarized concisely in a report.

3.9.1 Safety

All alternatives shall be designed with consideration to public safety and the safety of operations and maintenance personnel. Characteristics of safe designs include:

- adequate equipment ratings for the conditions studied and margin for unanticipated conditions
- use of standard designs for ease of operation and maintenance
- ability to properly isolate facilities for maintenance
- adequate facilities to allow for staged construction of new facilities

Consideration shall be given to address any other safety issues that are identified that are unique to a specific project or site.

3.9.2 Performance

The system performance with the proposed alternatives should meet or exceed all applicable design criteria.

3.9.3 Reliability

This guide assesses deterministic reliability by defining the topology, load, and generation conditions that the transmission system must be capable of withstanding safely. This deterministic approach is consistent with NERC, NPCC, ISO-NE, and NYSRC practice. Defined outage conditions that the system must be designed to withstand are listed in Table 4.1. The transmission system is designed to meet these deterministic criteria to promote the reliability and efficiency of electric service on the bulk power system, and also with the intent of providing an acceptable level of reliability to the customers.

Application of this guide ensures that all customers receive an acceptable level of reliability, although the level of reliability provided through this approach will vary. All customers or groups of customers will not necessarily receive uniform reliability due to inherent factors such as differences in customer load level, load shape, proximity to generation, interconnection voltage, accessibility of transmission resources, customer service requirements, and class and vintage of equipment.

3.9.4 Environmental

An assessment should be made for each alternative of the human and natural environmental impacts. Assessment of the impacts is of particular importance whenever expansion of substation fence lines or transmission rights-of-way are proposed. However, environmental impacts also should be evaluated for work within existing substations and on existing transmission structures. Impacts during construction should be evaluated in addition to the impact of the constructed facilities. Evaluation of environmental impacts will be performed consistent with all applicable National Grid policies.

3.9.5 Economics

Initial and future investment cost estimates should be prepared for each alternative. The initial capital investment can often be used as a simple form of economic evaluation. This level of analysis is frequently adequate when comparing the costs of alternatives for which all expenditures are made at or near the same time. Additional economic analysis is required to compare the total cost of each alternative when evaluating more complex capital requirements, or for projects that are justified based on economics such as congestion relief. These analyses should include the annual charges on investments, losses, and all other expenses related to each alternative.

A cash flow model is used to assess the impact of each alternative on the National Grid business plan. A cumulative present worth of revenue requirements model is used to assess the impact of each alternative on the customer. Evaluation based on one or both models may be required depending on the project.

If the justification of a proposed investment is to reduce or eliminate annual expenses, the economic analysis should include evaluation of the length of time required to recover the investment. Recovery of the investment within 5 years is typically used as a benchmark, although recovery within a shorter or longer period may be appropriate.

3.9.6 Technical Preference

Technical preference should be considered when evaluating alternatives. Technical preference refers to concerns such as standard versus non-standard design or to an effort to develop a future standard. It may also refer to concerns such as age and condition of facilities, availability of spare parts, ease of operations and maintenance, ability to accommodate future expansion, ability to implement, or reduction of risk.

3.9.7 Sizing of Equipment

All equipment should be sized based on economics, operating requirements, standard sizes used by the company, and engineering judgment. Economic analysis should account for indirect costs in addition to the cost to purchase and install the equipment. Engineering judgment should include recognition of realistic future constraints that may be avoided with minor incremental expense. As a guide, unless the equipment is part of a staged expansion, the capability of any new equipment or facilities should be sufficient to operate without constraining the system and without major modifications for at least 10 years. As a rough guide, if load growth is assumed to be 1% to 2%, then the minimum reserve margin should be at least 20% above the maximum expected demand on the equipment at the time of installation. However, margins can be less for a staged expansion.

3.10 Recommendation

A recommended action should result from every study. The recommendation includes resolution of any potential violation of the design criteria. The recommended action should be based on composite consideration of factors such as safety, the forecasted performance and reliability, environmental impacts, economics, technical preference, schedule, availability of land and materials, acceptable facility designs, and complexity and lead time to license and permit.

3.11 Reporting Study Results

A transmission system planning study should culminate in a concise report describing the assumptions, procedures, problems, alternatives, economic comparison, conclusions, and recommendations resulting from the study.

4.0 Design Criteria

4.1 Objective of the Design Criteria

The objective of the Design Criteria is to define the design contingencies and measures used to assess the adequacy of the transmission system performance.

4.2 Design Contingencies

The Design Contingencies used to assess the performance of the transmission system are defined in Table 4.1. In association with the design contingencies, this table also includes information on allowable facility loading. Control actions may be available to mitigate some contingencies listed in Table 4.1.

The reliability of local areas of the transmission system may not be critical to the operation of the interconnected NEPOOL system and the New York State Power System. Where this is the case, the system performance requirements for the local area under National Grid design contingencies may be less stringent than what is required by NERC Reliability Standards, NPCC Criteria, ISO-NE Reliability Standards, or NYSRC Reliability Rules.

4.2.1 Fault Type

As specified in Table 4.1, some contingencies are modeled without a fault; others are modeled with a three phase or a single phase to ground fault. All faults are considered permanent with due regard for reclosing facilities and before making any manual system adjustments.

4.2.2 Fault Clearing

Design criteria contingencies involving ac system faults on bulk power system facilities are simulated to ensure that stability is maintained when either of the two independent protection groups that performs the specified protective function operates to initiate fault clearing. In practice, design criteria contingencies are simulated based on the assumption that a single protection system failure has rendered the faster of the two independent protection groups inoperable.

Design criteria contingencies involving ac system faults on facilities that are not part of the bulk power system are simulated based on correct operation of the protection system on the faulted element. Facilities that are not part of the bulk power system must be reviewed periodically to determine whether changes to the power system have caused facilities to become part of the bulk power system. National Grid utilizes for this purpose a methodology based on applying a three-phase fault, uncleared locally, and modeling delayed clearing of remote terminals of any elements that must open to interrupt the fault.

4.2.3 Allowable Facility Loading

The normal rating of a facility defines the maximum allowable loading at which the equipment can operate continuously. The LTE and STE ratings of equipment may allow an elevation in operating temperatures over a specific period provided the emergency loading is reduced back to, or below, a specific loading in a specific period of time (for specific times, see Section 3.4).

The system should be designed to avoid loading equipment above the normal rating prior to a contingency and to avoid loading equipment above the LTE rating following a design contingency (see Table 4.1 contingencies a through i). Under limited circumstances, however, it is acceptable to design the system such that equipment may be loaded above the LTE rating, but lower than the STE rating. Loading above the LTE rating up to the STE rating is permissible for contingencies b, c, e, f, g, h, and i, for momentary conditions, provided automatic actions are in place to reduce the loading of the equipment below the LTE rating within 15 minutes, and it does not cause any other facility to be loaded above its LTE rating. Such exceptions to the criteria will be well documented and require acceptance by National Grid Network Operations.

The STE rating is dependent on the level of loading prior to applying a contingency. The published STE rating is valid when the pre-contingency loading is within the normal rating. When the pre-contingency loading exceeds the normal rating, the STE rating must be reduced to prevent equipment from exceeding its allowable emergency temperature.

In New England an additional rating, the Drastic Action Limit (DAL), is calculated for use in real-time operations. The DAL is an absolute operating limit, based on the maximum loading to which a piece of equipment can be subjected over a five-minute period without sustaining damage. Although the DAL is computed based on a five minute load duration, if equipment loadings reach a level between the STE and DAL limits, then immediate action is required to reduce loading to below LTE. The DAL is not used in planning studies or for normal operating situations. In some cases when the STE rating may be exceeded, it may be necessary to provide redundant controls to minimize the risk associated with failure of the automated actions to operate as intended.

4.2.4 Reliability of Service to Load

The transmission system is designed to allow the loss of any single element without a resulting loss of load, except in cases where a customer is served by a single supply. Where an alternate supply exists interruption of load is acceptable for the time required to transfer the load to the alternate supply.

Loss of load is acceptable for contingencies that involve loss of multiple elements such as simultaneous outage of multiple circuits on a common structure, or a circuit breaker failure resulting in loss of multiple elements. For these contingencies, measures should be evaluated to mitigate the frequency and/or the impact of such contingencies when the amount of load interrupted exceeds 100 MW. Such measures may include differential insulation of transmission circuits on a common structure, or automatic switching to restore unfaulted elements. Where such measures are already implemented, they should be assumed to operate as intended, unless a failure to operate as intended would result in a significant adverse impact outside the local area.

A higher probability of loss of customer load is acceptable during an extended generator or transformer outage, maintenance, or construction of new facilities. Widespread outages resulting from contingencies more severe than those defined by the Design Contingencies may result in loss of customer load in excess of 100 MW and/or service interruptions of more than 3 days.

4.2.5 Load Shedding

NPCC requires that each member have underfrequency load shedding capability to prevent widespread system collapse. As a result, load shedding for regional needs is acceptable in whatever quantities are required by the region. In some cases higher quantities of load shedding may be required by the Area or the local System Operator.

Manual or automatic shedding of any load connected to the National Grid transmission system in response to a design contingency listed in Table 4.1 may be employed to maintain system security when adequate facilities are not available to supply load. However, shedding of load is not acceptable as a long term solution to design criteria violations, and recommendations will be made to construct adequate facilities to maintain system security without shedding load.

4.2.6 Expected Restoration Time

The transmission restoration time for the design contingencies encountered most frequently is typically expected to be within 24 hours. Restoration times are typically not more than 24 hours for equipment including overhead transmission lines, air insulated bus sections, capacitor banks, circuit breakers not installed in a gas insulated substation, and transformers that are spared by a mobile substation. For some contingencies however, restoration time may be significantly longer. Restoration times are typically longer than 24 hours for generators, gas insulated substations, underground cables, and large power transformers. When the expected restoration for a particular contingency is expected to be greater than 24 hours, analysis should be performed to determine the potential impacts if a second design contingency were to occur prior to restoration of the failed equipment.

4.2.7 Generation Rejection or Ramp Down

Generation rejection or ramp down refers to tripping or running back the output of a generating unit in response to a disturbance on the transmission system. As a general practice, generation rejection or ramp down should not be included in the design of the transmission system. However, generation rejection or ramp down may be considered if the following conditions apply:

- acceptable system performance (voltage, current, and frequency) is maintained following such action
- the interconnection agreement with the generator permits such action
- the expected occurrence is infrequent (the failure of a single element is not typically considered infrequent)
- the exposure to the conditions is unlikely or temporary (temporary implies that system modifications are planned in the near future to eliminate the exposure or the system is operating in an abnormal configuration).

Generation rejection or ramp down may be initiated manually or through automatic actions depending on the anticipated level and duration of the affected facility loading. Plans involving generation rejection or ramp down require review and approval by National Grid Network Operations, and may require approval of the System Operator.

4.2.8 Exceptions

These Design Criteria do not apply if a customer receives service from National Grid and also has a connection to any other transmission provider regardless of whether the connection is open or closed. In this case, National Grid has the flexibility to evaluate the situation and provide interconnection facilities as deemed appropriate and economic for the service requested.

National Grid is not required to provide service with greater deterministic reliability than the customers provide for themselves. As an example, if a customer has a single transformer, National Grid does not have to provide redundant transmission supplies.

4.3 Voltage Response

Acceptable voltage response is defined in terms of maximum and minimum voltage in per unit (p.u.) for each transmission voltage class (Table 4.2), and in terms of percent voltage change from pre-contingency to post-contingency (Table 4.3). The values in these tables allow for automatic actions that take less than one minute to operate and which are designed to provide post-contingency voltage support. The voltage response also must be evaluated on the basis of voltage transients.

4.4 Stability

4.4.1 System Stability

Stability of the transmission system shall be maintained during and following the most severe of the Design Contingencies in Table 4.1, with due regard to reclosing. Stability shall also be maintained if the outaged element as described in Table 4.1, is re-energized by autoreclosing before any manual system adjustment.

In evaluating the system response it is insufficient to merely determine whether a stable or unstable response is exhibited. There are a number of system responses which may be considered unacceptable even though the bulk power system remains stable. Each of the following responses is considered an unacceptable response to a design contingency:

- Transiently unstable response resulting in wide spread system collapse.
- Transiently stable response with undamped power system oscillations.
- Entry of the line 396 apparent impedance at Keswick into the Keswick GCX SPS relay characteristic. (This SPS will be removed from service upon completion of the second 345 kV New Brunswick-New England tie line between Pt. Lepreau and Orrington.)

4.4.2 Generator Unit Stability

With all transmission facilities in service, generator unit stability shall be maintained on those facilities that remain connected to the system following fault clearing, for

a. A permanent single-line-to-ground fault on any generator, transmission circuit, transformer, or bus section, cleared in normal time with due regard to reclosing.

b. A permanent three-phase fault on any generator, transmission circuit, transformer, or bus section, cleared in normal time with due regard to reclosing.

Isolated generator instability may be acceptable. However, generator instability will not be acceptable if it results in adverse system impact or if it unacceptably impacts any other entity in the system.

Table 4.1: Design Contingencies

Ref.	CONTINGENCY (Loss or failure of:)	Allowable Facility Loading
a	A permanent three-phase fault on any generator, transmission circuit, transformer, or bus section	LTE
b	Simultaneous permanent single-line-to-ground faults on different phases of two adjacent transmission circuits on a multiple circuit tower (> 5 towers)[2]	LTE[1]
c	A permanent single-line-to-ground fault on any transmission circuit, transformer, or bus section, with a breaker failure	LTE[1]
d	Loss of any element without a fault (including inadvertent opening of a switching device	LTE
e	A permanent single-phase-to-ground fault on a circuit breaker with normal clearing	LTE[1]
f	Simultaneous permanent loss of both poles of a bipolar HVdc facility without an ac system fault	LTE[1]
g	Failure of a circuit beaker to operate when initiated by an SPS following: loss of any element without a fault, or a permanent single-line-to-ground fault on a transmission circuit, transformer, or bus section	LTE[1]
h	Loss of a system common to multiple transmission elements (e.g., cable cooling)	LTE[1]
i	Permanent single-line-to-ground faults on two cables in a common duct or trench	LTE[1]

Notes:

[1] Loading above LTE, but below STE, is acceptable for momentary conditions provided automatic actions are in place to reduce the loading of equipment below the LTE rating within 15 minutes.

[2] 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 an acceptable risk and therefore can be excluded. Other similar situations can be excluded on the basis of acceptable risk, subject to approval in accordance with Regional (NPCC) and Area (NYSRC or ISO-NE) exemption criteria, where applicable.

Table 4.2: Voltage Range

CONDITION	345 & 230 kV		115 kV[1] & Below	
	Low Limit (p.u.)	**High Limit (p.u.)**	**Low Limit (p.u.)**	**High Limit (p.u.)**
Normal Operating	0.98	1.05	0.95	1.05
Post Contingency & Automatic Actions	0.95	1.05	0.90	1.05

[1] Buses that are part of the bulk power system, and other buses deemed critical by Network Operations shall meet requirements for 345 kV and 230 kV buses.

Table 4.3: Maximum Percent Voltage Variation at Delivery Points

CONDITION	345 & 230 kV (%)	115 kV[1] & Below (%)
Post Contingency & Automatic Actions	5.0	10.0
Switching of Reactive Sources or Motor Starts (All elements in service)	2.0 *	2.5 *
Switching of Reactive Sources or Motor Starts (One element out of service)	4.0 *	5.0 *

[1] Buses that are part of the bulk power system, and other buses deemed critical by Network Operations shall meet requirements for 345 kV and 230 kV buses.

* These limits are maximums which do not include frequency of operation. Actual limits will be considered on a case-by-case basis and will include consideration of frequency of operation and impact on customer service in the area.

Notes to Tables 4.2 and 4.3:

a. Voltages apply to facilities which are still in service post contingency.
b. Site specific operating restrictions may override these ranges.
c. These limits do not apply to automatic voltage regulation settings which may be more stringent.
d. These limits only apply to National Grid facilities.

5.0 Interconnection Design Requirements

5.1 Objective of the Interconnection Design Requirements

The objective of the interconnection design requirements is to provide guidance on the minimum acceptable configurations to be applied when a new generator or transmission line is to be interconnected with the National Grid transmission system. The goal is to assure that reliability and operability are not degraded as a consequence of the new interconnection. National Grid will determine the configuration that appropriately addresses safety, reliability, operability, maintainability, and expandability objectives, consistent with this Transmission Planning Guide for each new or revised interconnection.

5.2 Design Criteria

5.2.1 Safety

Substation arrangements shall be designed with safety as a primary consideration. Standard designs shall be utilized for ease of operation and maintenance and to promote standardization of switching procedures. Substation arrangements shall also provide means to properly isolate equipment for maintenance and allow appropriate working clearances for installed equipment as well as for staged construction of future facilities. Consideration shall be given to address any other safety issues that are identified that are unique to a specific project or site.

5.2.2 Planning and Operating Criteria

Substation arrangements shall be designed such that all applicable Planning and Operating Criteria are met. These requirements may require ensuring that certain system elements do not share common circuit breakers or bus sections so as to avoid loss of both elements following a breaker fault or failure; either by relocating one or both elements to different switch positions or bus sections or by providing two circuit breakers in series. These requirements may also require that existing substation arrangements be reconfigured, e.g. from a straight bus or ring bus to a breaker-and-a-half configuration.

5.2.3 System Protection

Substation arrangements shall provide for design of dependable and secure protection systems. Designs that create multi-terminal lines shall not be allowed except in cases where Protection Engineering verifies that adequate coordination and relay sensitivity can be maintained when infeed or outfeed fault current is present.

To ensure reliable fault clearing, it generally is desirable that no more than two circuit breakers be required to be tripped at each terminal to clear a fault on a line or cable circuit. For transformers located within the substation perimeter, the incidence of faults is sufficiently rare that this requirement may be relaxed to permit transformers to be connected directly to the buses in breaker-and-a-half or breaker-and-a-third arrangements.

5.2.4 Reliability

Factors affecting transmission reliability shall be considered in interconnection designs. These factors include, but are not limited to:

- additional exposure to transmission outages resulting from additional transmission line taps, with consideration to length of the proposed tap,
- the number of other taps already existing on the subject line. In general, new taps will be avoided if three or more taps already exist,
- the number and type of customers already existing on the subject line and potential impacts to these customers resulting from a proposed interconnection,
- the existing performance of the subject line and how the proposed interconnection will affect that performance, and
- the impact on the complexity of switching requirements, and the time and personnel required to perform switching operations.

Periodic transmission assessments shall consider whether system modifications are necessary to improve reliability in locations where greater than three taps exist on a single transmission line.

5.2.5 Operability

Substation switching shall be configured to prevent the loss of generation for normal line operations following fault clearing. Generators shall not be connected directly to a transmission line through a single circuit breaker position except as noted in Section 5.4.2.

5.2.6 Maintainability

Substations shall be configured to permit circuit breaker maintenance to be performed without taking lines or generators out of service, recognizing that a subsequent fault on an element connected to the substation might result in the isolation of more than the faulted element. At existing substations with straight bus configurations, consideration will be given to modifying terminations in cases where an outage impacts the ability to operate the system reliably.

5.2.7 Future Expansion

Substation designs shall be based on the expected ultimate layout based on future existing system needs and physical constraints associated with the substation plot.

5.3 Standard Bus Configurations

Given the development of the transmission system over time and through mergers and acquisitions of numerous companies, several different substation arrangements exist within the National Grid system. Future substation designs are standardized on breaker-and-a-half, breaker-and-a-third, and ring bus configurations, depending on the number of elements to be terminated at the station. Other substation configurations may be retained at existing substations, but are evaluated in periodic transmission assessments to consider whether continued use of such configurations is consistent with the reliable operation of the transmission system.

Determination of the appropriate substation design is based on the total number of elements to be terminated in the ultimate layout, and how many major transmission elements will be terminated. Major transmission elements include networked transmission lines 115 kV and above and power transformers with at least one terminal connected at 230 kV or 345 kV.

5.3.1 Breaker-and-a-Half

A breaker-and-a-half configuration is the preferred substation arrangement for new substations with an ultimate layout expected to terminate greater than four major transmission elements or greater than six total elements. If the entire ultimate layout is not constructed initially, the substation may be configured initially in a ring bus configuration. Cases will exist where a breaker-and-a-half configuration is required with fewer elements terminated in order to meet the criteria stated above.

Major transmission elements are terminated in a bay position between two circuit breakers in a breaker-and-a-half configuration. Other elements such as capacitor banks, shunt reactors, and radial 115 kV transmission lines may be terminated on the bus through a single circuit breaker. Transformers with no terminal voltage greater than 115 kV may be terminated directly on a bus. It may be permissible to terminate 345-115 kV or 230-115 kV transformers directly on a 115 kV bus if there is no reasonable expectation that more than two such transformers will be installed. Such a decision requires careful consideration however, given the difficulty of re-terminating transformers to avoid tripping two transformers for a breaker fault or failure in the event that a third transformer is installed at a later time.

5.3.2 Breaker-and-a-Third

A breaker-and-a-third configuration is an acceptable alternate to a breaker-and-a-half configuration in cases where a breaker-and-a-half arrangement is not feasible due to physical or environmental constraints. Considerations for terminating elements on a bus are the same as for breaker-and-a-half, except that 345-115 kV or 230-115 kV transformers may be terminated directly on a 115 kV bus since additional transformers may be terminated in a bay without a common breaker between two transformers.

5.3.3 Ring Bus

A ring bus may be utilized for new substations where four or fewer major elements will be terminated or six or fewer total elements will be terminated. A ring bus also may be utilized as an interim configuration during staged construction of a substation.

5.3.4 Straight Bus

Many older substations on the system have a straight bus configuration, with each element terminating on the bus through a single breaker. Variations exist in which the bus is segmented by one or more bus-tie breakers, provisions are provided for a transfer bus, or the ability exists to transfer some or all elements from the main bus to an emergency bus. Periodic transmission assessments shall consider whether continued use of existing straight bus configurations is consistent with maintaining reliable operation of the transmission system.

New bulk power system substations shall not utilize a straight bus design. Straight bus designs may be utilized at non-bulk power system substations subject to the following conditions:

- A transfer bus is provided to facilitate circuit breaker maintenance.
- The transfer breaker protection system is capable of being coordinated to provide adequate protection for any element connected to the bus.

- Justification is provided to support deviating from the standard breaker-and-a-half, breaker-and-a-third, or ring bus configuration.
- All requirements of Section 5.2 are met.

5.4 Issues Specific to Generator Interconnections

5.4.1 Interconnection Voltage

It is desirable to connect generators at the lowest voltage class available in the area for which an interconnection is feasible. In general, small generators no larger than 20 MW will be interconnected to the transmission system only when there is no acceptable lower voltage alternative in the area and it is not feasible to develop a lower voltage alternative.

5.4.2 Interconnection Facilities

The minimum interconnection required for all generators is a three-breaker ring bus. Additional circuit breakers and alternate substation configurations may be required when interconnecting multiple generating units. Generators shall not be connected directly to a transmission line through a single circuit breaker position unless an exception is granted as noted below.

Exceptions to the Generators Interconnection Requirements

Exceptions may be granted for (1) generators connected to radial transmission lines, and (2) for small generators no larger than 20 MW. Exceptions shall be evaluated on a case-by-case basis and shall be granted only when the following conditions are met:

- Protection Engineering verifies that the transmission line and interconnection facilities can be protected adequately, while ensuring that transmission system protective relay coordination and relay sensitivity can be maintained.
- Transmission Planning verifies that transmission reliability is not adversely impacted by assessing the Design Criteria listed above in Section 5.2 above pertaining to safety, planning and operating criteria, reliability, and maintainability.
- Provisions acceptable to National Grid are made to accommodate future expansion of the interconnection to at least a three-breaker ring bus.

5.4.3 Status of Interconnection Design

The design for any generator interconnection is valid only for the generating capacity and unit characteristics specified by the developer at the time of the request. Any modifications to generating capacity and unit characteristics require a separate system impact study and may result in additional interconnection requirements.

Modifications to the interconnection design may be required as a result of future modifications to the transmission system. National Grid will notify the generation owner when such modifications are required.

6.0 Glossary of Terms

Bulk Power System

The interconnected electrical system comprising generation and transmission facilities on which faults or disturbances can have a significant impact outside the local area.

Contingency

An event, usually involving the loss of one or more elements, which affects the power system at least momentarily.

Element

Any electric device with terminals which may be connected to other electric devices, such as a generator, transformer, transmission circuit, circuit breaker, an HVdc pole, braking resistor, a series or shunt compensating device or bus section. A live-tank circuit breaker is understood to include its associated current transformers and the bus section between the breaker bushing and its free standing current transformer(s).

Fault Clearing - Delayed

Fault Clearance consistent with correct operation of a breaker failure protection group and its associated breakers or of a backup protection group with an intentional time delay.

Fault Clearing - Normal

Fault Clearance consistent with correct operation of the protection system and with correct operation of all circuit breakers or other automatic switching devices intended to operate in conjunction with that protection system.
Note: Zone 2 clearing of line-end faults on lines without pilot protection is normal clearing, not delayed clearing, even though a time delay is required for coordination purposes.

High Voltage dc (HVdc) System, Bipolar

An HVdc system with two poles of opposite polarity and negligible ground current.

Interface

A group of transmission lines connecting two areas of the transmission system.

Load Cycle

The normal pattern of demand over a specified time period (typically 24 hours) associated with a device or circuit.

Load Level

A scale factor signifying the total load relative to peak load or the absolute magnitude of load for the year referenced.

Loss of Customer Load (or Loss of Load)

Loss of service to one or more customers for longer than the time required for automatic switching.

Point(s) of Delivery

The point(s) at which the Company delivers energy to the Transmission Customer.

Special Protection Systems

A protection system designed to detect abnormal system conditions and take corrective action other than the isolation of faulted elements. Such action may include changes in load, generation, or system configuration to maintain system stability, acceptable voltages, or power flows. Automatic underfrequency load shedding and conventionally switched locally controlled shunt devices are not considered to be SPSs.

Supply Transformer

Transformers that only supply distribution load to a single customer.

Transfer

The amount of electrical power that flows across a transmission circuit or interface.

Transmission Customer

Any entity that has an agreement to receive wholesale service from the National Grid transmission system.

Transmission Transformer

Any transformer with two or more transmission voltage level windings or a transformer serving two or more different customers.

Table 3-1 Most Severe Planning Criteria Violations in Rhode Island

Dispatch Stress	First Contingency	Second Contingency	Effect on Rhode Island System without the RI Reliability Project	Mitigation without the RI Reliability Project	Effect on Rhode Island System with the RI Reliability Project
Stressed Dispatch on a peak load day (critical 115 kV RI generator out of service)	332 345 kV Line (W. Farnum to Kent County)	S-171S 115 kV line (or any breaker failure contingency that causes the loss of the S-171S)	Voltage Collapse for a large part of Rhode Island (causing a black-out)	Over 500 MW of load must be shed after the first contingency but prior to the second contingency	No criteria violations
Stressed Dispatch on a peak load day (critical 115 kV RI generator out of service)	332 345 kV Line (W. Farnum to Kent County)	T-172S 115 kV line (or any breaker failure contingency that causes the loss of the T-172S)	Voltage Collapse for a large part of Rhode Island (causing a black-out)	Over 500 MW of load must be shed after the first contingency but prior to the second contingency	No criteria violations
Normal Dispatch on a peak load day (all critical 115 kV RI generators in service)	332 345 kV Line (W. Farnum to Kent County)	S-171S 115 kV line (or any breaker failure contingency that causes the loss of the S-171S)	Severe Overloads	300 MW of load must be shed after the first contingency but prior to the second contingency	No criteria violations
Normal Dispatch on a peak load day (all critical 115 kV RI generators in service)	332 345 kV Line (W. Farnum to Kent County)	T-172S 115 kV line (or any breaker failure contingency that causes the loss of the T-172S)	Severe Overloads	300 MW of load must be shed after the first contingency but prior to the second contingency	No criteria violations
Stressed or Normal Dispatch on a peak load day	332 345 kV Line (W. Farnum to Kent County)	K-189 115 kV line (or any breaker failure contingency that causes the loss of the K-189)	Significant Overload	100 MW of load must be shed after the first contingency but prior to the second contingency	No criteria violations