Technical Manual TM 1.2.00
Electric Transmission Planning
November 4th, 2022

AVANGRID ELECTRIC TRANSMISSION PLANNING MANUAL CRITERIA & PROCESSES

New York State Electric & Gas (NYSEG)
Rochester Gas and Electric (RG&E)
Central Maine Power (CMP)
Maine Electric Power Company (MEPCO)
The United Illuminating Company (UI)

Revision	Date	Description	Author
00	7/28/2011	Issue for Iberdrola-USA Planning consolidation	AG System Planning
01	10/31/2014	Update for: - Maine PUC planning assumptions - Criteria vs Process document organization change	Denis Howe, Justin Michlig, Chris Morin
02	02/15/2017	Issued for Avangrid Planning consolidation - Incorporate UI criteria	Chris Morin, Chris Malone, Tim Lynch
03	05/31/2017	Updated Avangrid Voltage Criteria	Hasan Matin
04	05/25/2018	Removed the footnote for NY voltage criteria exception as it is no longer applicable	Chris Morin
05	6/30/2019	Update for: - Added Loss of Load Criteria - Various other revisions	Edward Roedel
06	11/4/2022	Periodic review & Update	Edward Roedel

AVANGRID

Table of Contents

1. Introduction

This document defines transmission system design criteria and guidelines that maintain an acceptable electric transmission system that meets the needs of Avangrid customers in a safe, reliable, and economical manner.

Planning criteria allow for the identification of developing problems and ensure that plans adequately address service requirements. The Avangrid Transmission Planning criteria is to be utilized when analyzing the transmission system reliability as part of reliability studies and new transmission interconnections.

Failure to meet any one criterion can justify a system improvement. Some criteria, such as those dealing with safety, require a more immediate response and will take priority over other problems that may be deferred. Transmission planners must evaluate each proposed project against the planning criteria and establish its priority. In addition to the priority of a project, those deemed necessary for compliance with Reliability Standards will be non-discretionary as they are established by deterministic North American Electric Reliability Corporation (NERC) standards.

Transmission Planning reserves the right to routinely amend these criteria at any time.

1.1 Jurisdiction of Criteria

Avangrid strives to ensure that its transmission planning criteria does not conflict with jurisdictional authority. The following criteria are applied when analyzing the transmission system:

1. NERC Reliability Standards
2. NPCC Standards
3. ISONE/NYISO criteria through Open Access Transmission Tariff (OATT) or legal agreement
4. Local Transmission Planning Criteria including local regulatory bodies:
    a. Maine Public Utility Commission (MPUC)
    b. Connecticut Public Utilities Regulatory Authority (PURA)
    c. New York State Department of Public Service (DPS)
    d. New York State Reliability Council (NYSRC)

The Avangrid Transmission Planning Manual is designed to provide criteria required to supplement federal and regional standards (such as voltage limits). This document is designed to contain all criteria to study the reliability of its local transmission system and maintain compliance with state statutes along with commission orders [1].

1.2 Applicability Flow Chart

To aid in determining the application of standards and criterion, the following flow cart is provided (Figure 1).

[1] Methods for planning and designing the local transmission system are consistent with the Maine Public Utilities Commission order in Docket No. 2011-00494, "Investigation into Maine Electric Utilities Transmission Planning Standards and Criteria"; which established "Safe Harbor" assumptions and practices to support Certificates of Public Convenience and Necessity.

Planning Criteria Applicability

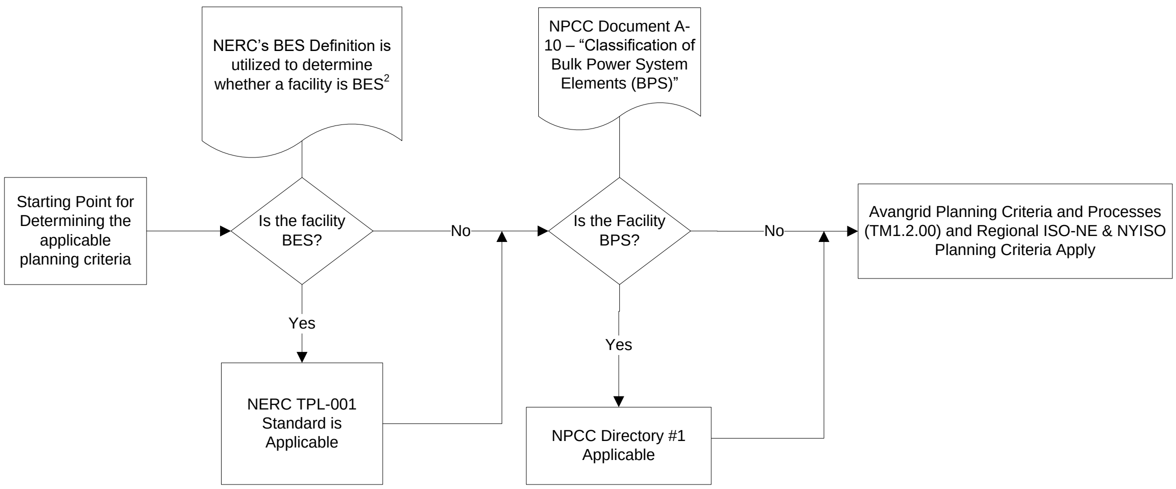

Figure 1: Applicability Flow Chart[2]

2. Transmission Planning Tools

Avangrid utilizes multiple types of power system simulation software. This software allows engineers to conduct reliability testing, analyze potential system deficiencies and test for solutions. The following products are utilized in addition to the standard suite of Microsoft Office and Windows tools.

PSS®E

Siemens Power System Simulator for Engineering (PSS®E) is a power system simulator used for transmission analysis. The primary uses within Avangrid are power flow and dynamic simulations. In addition to typical transmission planning analysis, Avangrid utilizes PSS/E for studying Geomagnetic Induced Currents (GIC).

ASPEN – ONELINER™

This program is primarily utilized by the Protection & Control group within Avangrid. Transmission Planning utilizes the program to calculate short circuit current and system impedance information. This contributes to the required transmission system short circuit analysis and providing input to dynamic simulations performed in PSS®E.

TARA

PowerGem's Transmission Adequacy and Reliability Assessment (TARA) is a steady state power flow software tool with modeling capabilities and analytical applications that include N-1/N-1-1 reliability analysis, transfer limit calculation, preventive and corrective dispatch, outage analysis, etc.

ENFUZION

Axceleon's Enfuzion software is an industrial strength render farm management system. This software can maximize the utilization of multi-core processors. This is essential when running large amounts of contingencies specifically during stability analysis.

[2]The Bulk Electric System (BES) is defined as transmission elements and real and reactive resources connected at 100kV as well as specific facilities subject to inclusion and exclusion per the [Bulk Electric System Definition Reference Document]

3. Description of the Avangrid Transmission System

Avangrid is a subsidiary of the global energy leader Iberdrola, SA. Avangrid transmission facilities owned by the companies of Central Maine Power (CMP), New York State Electric and Gas (NYSEG), Rochester Gas and Electric (RG&E) and United Illuminating (UI). The Avangrid transmission infrastructure supports more than 1.8M customers with ~8200 miles of transmission lines and over 900 substations. As regulated utilities, each company has various obligations and commitments to ensure construction of a reliable transmission system.

The four operating companies of the Avangrid family fall under the jurisdiction of the Federal Energy Regulatory Commission (FERC), NERC, and the NPCC. In addition to the federal and regional entities, CMP is under the purview of the New England Independent System Operator (ISO-NE) and the Public Utility Commission of Maine (MPUC). Similarly, NYSEG and RG&E are part of the New York Independent System Operator (NYISO), New York State Reliability Council (NYSRC), and New York State Public Service Commission (NYPSC). UI is under the purview of the New England Independent System Operator (ISO-NE) and the Public Utility Commission of Connecticut.

The Maine Electric Power Company (MEPCO) is also a transmission owning company located in the state of Maine. It consists of a majority stake ownership of CMP and minority ownership of Emera Maine. Criteria and responsibilities for CMP are also applicable to MEPCO. Together RG&E and NYSEG may be referred to as New York companies throughout this document.

3.1 Definitions of the Transmission System

The broadest definition of the transmission system is given by FERC. This definition is independent of operating voltage and states, "Moving bulk energy products from where they are produced or generated to distribution lines that carry the energy products to consumers." Generally, a FERC seven-factor test, established in FERC Order 888, is applied in the determination of transmission vs. distribution. Further clarification is left to the state for setting boundaries of transmission vs. local distribution.

In 2014 the NERC Bulk Electric System (BES) revised definition became effective. This defines clearly all facilities which are under the purview of the NERC Reliability Standards. All NPCC participants have registered their list of BES facilities with NPCC.

A more narrowly defined set of transmission elements is governed by NPCC's Document A-10 "Classification of Bulk Power System Elements." Bulk Power System (BPS) facilities are defined as those facilities whose performance affects the reliability of supply to other utilities and customers beyond the local area. The Bulk Power System is designed based on the requirements of the NPCC "Design and Operation of the Bulk Power System" (NPCC Directory #1) and other NPCC directories and criteria.

All Avangrid regulated operating companies participate within the purview of a regional Independent System Operator (ISO). These are ISO-NE for CMP and UI, NYISO for RG&E and NYSEG. As a part of membership in an ISO, each member is bound to construct facilities that maintain reliability on the transmission system. These agreements bind CMP and UI to utilize ISO-NE's Planning Procedure 3 and NYSEG and RGE to utilize the approved Reliability Rules in New York.

Local transmission facilities are all other transmission facilities that are primarily used to supply local area load, large industrial customers and/or connect smaller generation. The local transmission system generally consists of facilities that operate between 115 kV and 34.5 kV. Distribution facilities dedicated to serving customers are covered by the Avangrid Distribution Planning Criteria[3].

RG&E supplies a portion of the City of Rochester from networked transmission facilities that are operated at 11 kV. These bi-directional flow network facilities are operated in parallel with the 115 kV and 34.5 kV transmission systems and are part of the transmission system.

4. Transmission Planning Criteria

This section is designed to house the metrics used to judge system performance. These criteria are to be met when analyzing Planning Events and Normal Contingencies.

4.1 Facility Ratings

Avangrid utilizes ratings of its facilities in its transmission planning studies to ensure safe operation without excessive loss of equipment life. Ratings to be used are consistent with those developed in compliance with the NERC FAC-008 standard for the BES and approved methods for local transmission facilities.

Three categories of ratings are utilized:

1) **Normal Rating:** This rating is the continuous rating of the transmission facility adjusted to seasonal ambient conditions. There are no restrictions on utilization of the full normal rating for any extent of time.
2) **Long Term Emergency Rating (LTE):** Applicable for a 4-hour time period for all seasons in New York. For Maine and Connecticut, the Winter LTE rating uses a 4-hour duration while the Summer LTE rating utilizes a 12-hour duration. Facilities may utilize the LTE rating only post contingency. The transmission facility must return to a loading level below its normal rating once the applicable LTE time duration has expired.
3) **Short Term Emergency Rating (STE):** This rating is applicable for short term loadings on transmission facilities after a contingency has occurred. This is assuming the pre-contingent loading is within the facility's normal rating. The maximum length of time that a facility may be loaded utilizing its STE limit is 15 minutes. After which the loading must decrease below LTE.
4) **Drastic Action Limit (DAL):** This rating has been developed for operational use only. It is not intended to be utilized in planning studies.

Table 1: Thermal Rating Applicability

System Condition	Maximum Time Interval	Maximum Allowable Facility Rating
Normal (all facilities in)	Continuous	Normal Rating
Post Contingency	LTE duration[4]	Long Time Emergency (LTE) Rating
	15 Minutes	Short Time Emergency (STE) Rating

[3] Avangrid Technical Manual, TM 1.61.00, "Distribution Planning Criteria"
[4] For New York OpCo's the LTE duration is 4 hours. In New England LTE duration is 4 hours in Winter and 12 hours in Summer

4.2 Voltage

4.2.1 Steady State

When analyzing the transmission system, voltage must remain within the steady state bandwidth of 0.95 to 1.05 V PU. This range is to be maintained prior to and after a contingency occurs on the transmission system. Performance with this voltage range is applicable to the contingencies described in Section 5.3. The table below summarizes the Avangrid voltage criteria limits, including those used for Delta-V.

Table 2 - Avangrid Planning Voltage Criteria

Planning Voltage Criteria - Avangrid		
Limit	Level	Comment
Maximum	1.05 pu	Applies to all planning time periods
Minimum (Steady State)	0.95 pu	Applies to time periods after automatic actions including LTC's, etc.
Minimum (Post Transient)[5]	0.90 pu	Applies to time periods prior to automatic actions including LTC's, etc.
Collapse	0.80 pu / Non-Convergence	Results calculated at or below 0.80 pu are considered to be indeterminate
Delta-V (N-0)	3.0%	Delta-V testing includes the effects of routine switching such as Transformer or Reactor LTC's and Capacitor Bank Switching or the starting of large industrial loads
Delta-V (N-1)	5.0%	

Avangrid strives to provide adequate voltage to all customers. For residential and commercial purposes the voltage variation should not exceed the limits specified in ANSI C84.1 Range A. In addition, the State of Maine also requires that CMP provide service to customers which meet voltage criteria within MPUC 65-407 Chapter 320[6].

4.2.2 Flicker (Delta-V)

Avangrid considers the normal action of shunt connected transmission devices (either directly or through a transformer) to be within the scope of devices applicable to voltage flicker. The maximum allowable flicker on the transmission system by the starting of large motors, the switching of capacitor banks, or other devices is defined by the IEEE Standard 1453 flicker curve (see Figure 2). The “Borderline of Visibility” curve is used as the design criteria for the transmission system.

With all elements of the transmission system operating and in-service, the instantaneous bus voltages must not change by more than 3% while the number of switching events is limited to less than one per hour. Additionally,

[5] The "Minimum (Post Transient)" analysis (i.e. locked taps study) is not routinely performed for all area planning studies unless there are indications from study results that signal a potentially weak transmission system. If a weak transmission system is suspected as evidenced by marginal pre/post contingency voltages this post-Transient analysis is recommended.
[6] https://www.maine.gov/sos/cec/rules/65/407/407c320.docx

as seen on the curve, voltage flicker within the frequency range of 2 to 8 dips per second (characteristics of an arc furnace) shall be less than 0.5%.

In addition to the maximum voltage flicker threshold with all facilities in-service, Avangrid also utilizes a criterion to test a facility out-of-service. With one element out of service a 5% flicker is acceptable for switching frequencies of one or less per hour. These criterions will not be applied retroactively to equipment already in-service. When retiring a transmission line, impacts to the magnitude of flicker should be considered.

This Avangrid Delta-V criterion is summarized in Table 2 above.

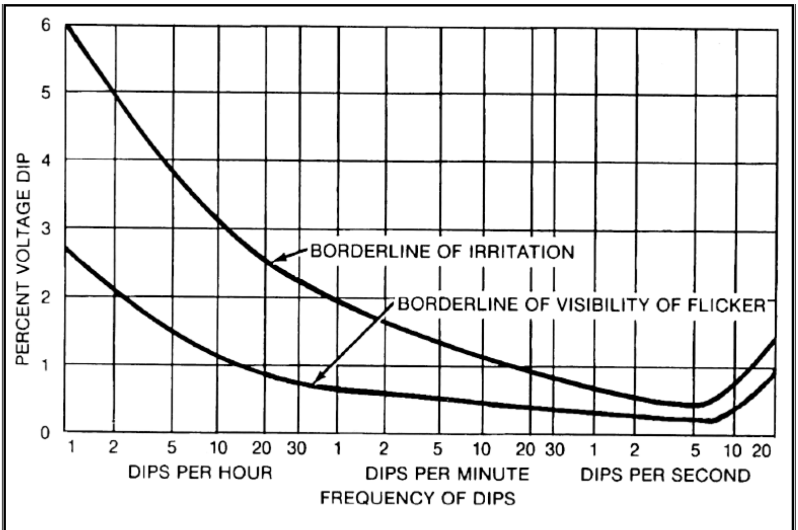

Figure A.1—Flicker tolerance curve from IEEE Std 141-1993/IEEE Std 519-1992

Figure 2: Voltage Flicker Limitation Curve

Voltage change during a fault, generation trip, or non-routine switching (e.g. restoration activities, etc.) are not considered voltage flicker and are not bound by this section.

4.3 Dynamic/Transient/Time Domain Simulation

NERC, ISO-NE, NYISO, NPCC and other regional organizations have developed stability criteria or guides that govern what is an acceptable system response to specific design contingencies in their respective jurisdictions.

- NERC Transmission Planning Performance Requirements - TPL-001[7]
- NPCC Regional Reliability Reference Directory #1[8]
- ISO New England Planning Procedure No. 3, revised September 15, 2017[9]
- New York ISO Transmission Expansion Interconnection Manual, July 2017[10]
- New York State Reliability Council (NYSRC) Reliability Rules & Compliance Manual, May 2018[11]

[7] http://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-4.pdf
[8] https://www.npcc.org/Standards/Directories/Forms/Public%20List.aspx
[9] http://www.iso-ne.com/participate/rules-procedures/planning-procedures
[10] http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Planning/tei_mnl.pdf
[11] http://www.nysrc.org/pdf/Reliability%20Rules%20Manuals/RRC%20Manual%20V43%20Final[4070].pdf

4.4 Short Circuit Criteria

Transmission Planning coordinates with the Protection & Control department to ensure that short circuit analysis and breaker duty studies are conducted when new transmission system and interconnection projects are being considered. Avangrid utilizes ASPEN ® to conduct its short circuit analysis. Table 3 contains the assumptions used for simulation of short circuit. Similar assumptions should be used with alternate software.

Table 3 - Avangrid Planning Short Circuit Simulation Parameters

ASPEN Short Circuit Modeling Assumptions		
X/R Options		
Compute ANSI x/r ratio		YES
Assume Z2 equals Z1 for ANSI x/r calculation		YES
X-only calculation	If X is 0 use:	0.0001 pu.
R-only calculation	If R is 0 use:	Method 1
	Rc	0.0001 pu.
	Typical X/R ratio (g) for generators	60
	Typical X/R ratio (g) for transformers	30
	Typical X/R ratio (g) for all other equipment	10
Fault Simulation options		
Pre-fault voltage	Assumed "Flat" with V(pu.)	1.05/1.04 for CMP/UI
Ignore shunts	Loads	YES
	Transmission line G + jB	YES
	Shunts with + sequence values	-
	Transformer line shunts	-
Generator Impedance	Subtransient	-
MOV-protected series capacitor	Iterate short circuit solutions	YES
	Acceleration Factor	0.4
Define fault MVA as product of	Current and pre-fault voltage	-
Current limited generators	Ignore current limits	-
ANSI/IEEE Breaker Checking Options		
Fault types		3LG, 2LG, 1LG
For X/R calculation, use		Separate X-only, R-only networks
In 1LG faults, allow up to 15% higher rating for		Symmetrical current rated
Force voltage range factor K=1 in checking	Symmetrical-current rated breakers	YES
	Max design or higher	121
Miscellaneous options	Treat all sources as remote	YES
All generation modeled online to maximize fault current		YES

4.5 Load Loss Acceptability

Loss of Load (LoL) is an important measure of the transmission system dependence on specific system facilities and is one reliability indicator which provides engineers with quantitative methods for revealing system weaknesses.

4.5.1 Consequential Load Loss

The Avangrid transmission systems shall be designed to limit the load loss for sustained interruptions resulting from N-1 single line and transformer contingencies. Consideration should be given to system designs where failure of equipment could lead to extended restoration times (e.g. underground cable failures). The following criteria are intended to be used to main system reliability and not utilized as a design guide.

To limit consequential load loss, Avangrid transmission and subtransmission systems shall be designed to:

1. Limit load loss to 25 MW for single line and transformer design contingencies[12]
2. Not exceed 10 MW between automatic motor operated disconnect switches[13]
3. Not automatically sectionalize in more than two locations[14] for each single line or transformer design contingency.

Large commercial or industrial customers taking service from a transmission or subtransmission circuit are not subject to these requirements and may elect to exceed the 25 MW consequential load loss threshold.

Within Maine a maximum of 60 MW consequential load loss may be accepted for a single element event that occurs during a maintenance outage.

4.5.2 Non-Consequential Load Loss

During a NERC Planning Event on the BES transmission system or single contingency on the Local Transmission system, Avangrid does not allow the use of Non-Consequential Load Loss to maintain system performance criteria as a permanent solution[15].

For temporary measures, after the second contingency of a P6 event, Non–Consequential Load Loss will be permitted to bring the system within pre-contingent facility rating operating limits assuming STE ratings have not been exceeded. In addition, for temporary reliability improvement, to ensure adequate voltage and protect customer equipment, Under Voltage Load Shedding (UVLS [16]) would be required to bring a low voltage condition within criteria. In a condition of projected voltage collapse manual or automatic load shedding schemes will be insufficient.

4.6 Harmonics

Harmonic distortion caused by customer load characteristics and capacitor banks shall be limited such that harmonic voltage distortion on the system shall not exceed any applicable ANSI standards for equipment connected to the system. Also, as stated in IEEE Standard 519-1992 (see below), voltage distortions shall not exceed 3% for any single frequency or 5% total harmonic distortion and shall not injuriously affect equipment or its service to others. However, it is recognized that reasonable engineering judgment must be used in the application of these limits to balance compliance costs against adverse consequences of excess harmonic distortion.

---

[12] Initial load loss should be assessed after any automatic throw over schemes that exclusively use fast acting devices (e.g., bus transfer schemes)

[13] 10 MW limit shall not be assessed on radial subtransmission circuits. i.e., no tie lines available, regardless of switch status

[14] A location is intended to identify an area single facility that may have multiple switching points (e.

[15] Non-Consequential Load Loss is only accepted on a temporary basis when allowed by NERC standards. A binding commitment to provide a solution must be developed to improve the transmission system post contingent response. Temporary solutions for reducing line loading must be conducted within facility loading capabilities. When voltage criterion is not met, an automatic means of bringing the system within boundaries, such as UVLS, should be temporarily used. Automatic or manual load shedding based on voltage sensing is not sufficient in the case of voltage collapse.

[16] UVLS Loss of load will only be accepted on a temporary basis. A binding commitment to provide a solution must be developed to improve the transmission system post contingent voltage response must exist. Temporary solutions for reducing line loading must be conducted within facility loading capabilities. When voltage criteria are not met, an automatic means of bringing the system within boundaries, such as UVLS, should be used. Automatic or manual load shedding based on voltage sensing is not sufficient in the case of voltage collapse.

Bus Voltage at PCC	Individual Voltage Distortion (%)	Total Voltage Distortion THD (%)
69 kV and below	3.0	5.0
69.001 kV through 161 kV	1.5	2.5
161.001 kV and above	1.0	1.5
NOTE — High-voltage systems can have up to 2.0% THD where the cause is an HVDC terminal that will attenuate by the time it is tapped for a user.		

Figure 3: Voltage Distortion Limits

4.7 Spare BES Equipment

The NERC TPL-001 standard requires Avangrid to assess the impact to the BES system if long lead time equipment owned by Avangrid is unavailable during P0, P1 and P2 events. If studied events show criteria violations corrective action plans must be developed. Avangrid considers the following BES equipment to have lead times in excess of one year:

- Power Transformers
- Underground Cables
- Phase-Angle Regulating Transformers (PARs)
- Shunt Reactors

If suitable spare equipment is owned by Avangrid and can be installed in less than 12 months, this analysis and resulting corrective action plans are not required.

4.8 Nuclear Plant Interface Requirements (NPIR)

Avangrid has a single nuclear generating station directly connected to its transmission system, Ginna, located in the RG&E territory. In accordance with the NUC-001 standard there are specific criteria that govern limits on facilities and/or elements identified as being part of delivering off-site power to the Ginna station. Refer to the latest NPIR documentation for a detailed list of the applicable criteria and facility limits.

4.9 Remedial Action Schemes (RAS)

AVANGRID believes that the installation of new Remedial Action Schemes (RASs) to mitigate reliability criteria violations which could be otherwise addressed by traditional solutions (e.g., transmission upgrades and non-wired alternatives) is not a suitable long-term engineering practice. Therefore, AVANGRID does not permit new RASs on the AVANGRID-owned transmission or sub-transmission systems.

Time-Sensitive Need Exception

RASs may be considered, at the discretion of AVANGRID, for the temporary resolution of existing or time-sensitive[17] and/or critical[18] reliability needs for which no reasonable operator intervention is possible and where a permanent traditional transmission solution (e.g., transmission lines, shunt reactors, substations, etc.) or Non-Wires Alternative solution could not be in constructed within the requisite time. A permanent solution which would permit the retirement of the temporary RAS must be pursued in parallel.

[17] Needs resulting from spot load or generator interconnections are not considered to be time-sensitive reliability needs and no temporary RAS solution is permitted.
[18] System deficiencies which, based on factors such as expected exposure and predicted impact, would threaten Avangrid's ability to safely and securely operate its transmission system.

EXISTING RASS

Existing schemes that meet the RAS definition will be permitted to remain in use and maintained in accordance with applicable reliability criteria. When conditions are such that the RAS is no longer required, the RAS shall be retired.

5. Simulation and Assumptions

This section of the Avangrid Transmission Planning manual is designed to guide model setup, scenarios, and illustrate general study assumptions to use.

5.1 Model Selection

Selecting a model that represents the area in question is one of the most important steps of a transmission planning study. The model needs to have enough detail to represent the condition and location being studied yet not so much as to inhibit the completion of a study. Avangrid Transmission Planning engineers are directed to utilize engineering judgment along with direction from regulating bodies to ensure use of models that are effective in studies. When developing models and studies it is important to:

- Utilize ratings reflective of the time period being analyzed
- Construct realistic transmission operating conditions
- Conduct simulations of the spectrum of required contingencies
- Forecast loads to ensure the system performs within the range of loading over time
- Take into effect the higher forced outage rate of generation

5.2 Transmission System Operating Conditions

The transmission system is susceptible to facilities being forced out of service during outages. In addition, many pieces of equipment require routine maintenance or end-of-life replacement for which facilities must be de-energized. To perform construction activities on the transmission system or ensure adequate clearance to energized equipment, facilities may need to be removed from service. Collectively forced outages (contingencies) and Maintenance/Construction outages (Planned outages) may be referred to as “Outages” throughout this planning criteria.

Transmission planning studies are conducted to analyze system contingencies and ensure that the transmission system is capable of remaining within specified voltage, thermal, short circuit and stability criterion for various system conditions. When deficiencies are discovered, additional analysis is completed to identify the reinforcements that would allow the transmission system to operate under normal conditions and single outage contingency scenarios, as well as planned maintenance conditions at off-peak load levels. Subsequent to their identification, reinforcements are budgeted as projects and constructed.

Transmission Planning performs most analyses using a computer load flow programs. Models include existing and future system configurations. Generally, engineers analyze simulations for winter and summer peak, shoulder, light and minimum load conditions. Additional applicable scenarios may be analyzed to ensure that the transmission network will perform adequately under all reasonably probable conditions.

5.2.1 Normal Operating Conditions

Normal conditions are present during system intact (all lines & equipment in) periods. Normal conditions include extremes of customer loads and generator forced/scheduled outages or being dispatched offline.. This condition serves as a benchmark against which to measure other operating conditions. All transmission facilities must be rated to carry their 90/10[19] peak load at N-0 without load transfers.

Both NERC and NPCC require considerations for the loss of equipment that have long lead times or are critical to maintain the reliability of the transmission system. An extended outage of a single generating plant or unit or a single bulk power transformer (115 kV and above on the low side) is also considered to be a Normal Operating Condition. Whenever a generating plant or unit or Bulk Power System transformer is going to be out of service for an extended period of time as a planned outage, Transmission Planning will determine what impact the next contingency would have on the transmission system and recommend a solution to any system problems that may be identified.

5.2.2 Scheduled and Maintenance Outage Operating Condition

Frequently, system operators and field crews must remove a transmission network element from service. These elements may be removed to perform maintenance, construct new facilities, or provide electrical clearance for adjacent work being performed. Removal of elements for these conditions shall be considered in Transmission Planning analysis.

Analysis of the BES, BPS and other non-local jurisdictional facilities will be in accordance to applicable governing documents. When considering reliability on the local transmission systems in Maine defined single contingencies should be reviewed for facilities being scheduled out of service at a calculated load level based on the Maine Safe Harbor criteria[20], or at the load level expected for the time of the scheduled outage. It should be expected that mobile transformers will be available to support the transmission or distribution system, if needed for reliability.

5.3 Contingencies

Avangrid's transmission system is classified into three main categories, BPS[21], BES[22] and "Local" with some overlap. All three element classifications are tested differently as their impact on the area power system varies, however all facilities may be subject to different regional requirements[23]. In general:

1. BPS elements are tested in accordance with:
    a. NPCC Directory #1 / NYSRC Reliability Rules & Compliance Manual[24]
    b. NERC Planning Standard TPL-001
    c. Avangrid Transmission Planning Criteria
2. BES elements are tested in accordance with:
    a. NERC Planning Standard TPL-001
    b. Avangrid Transmission Planning
3. Local Transmission System elements are tested in accordance with:
    a. Avangrid Transmission Planning Manual – Criteria & Processes

---

[19] 90/10 peak load is a load level with a 10% chance of occurring each year based on weather

[20] Maintenance outage testing will be derived as described in: "Maine Public Utilities Commission, Investigation into Maine Electric Utilities Transmission Planning Standards and Criteria, No. 2011-00494 Stipulation at 6."

[21] As defined via the NPCCA-10 methodology

[22] As defined by NERC as the +100kV brightline with applicable inclusions and exclusions

[23] Regional requirements examples include NYSRC Reliability Rules and ISO-NE Planning Procedure #3

[24] NYSRC Reliability Rules are only required for NYSEG and RG&E Assets:

Avangrid defines Single Outage contingencies[25] for the Local Transmission System as a three-phase fault and normal clearing of the following elements:

1. Transmission Line
2. Transformer
3. Generator
4. Opening one terminal of a facility without a fault
5. Shunt Device
6. Double-circuit transmission tower[26]

5.3.1 Multiple Contingencies

Avangrid strives to accurately and realistically assess the occurrence of consecutive contingency events on the transmission system. Two time frames are important for testing the system capabilities for a second outage.

Post Contingency Operator Actions
NPCC[27], ISO-NE[28] and NYSRC[29] have issued guidance on how to consider the operator adjustment time in-between the completion of the first contingency event and in preparation for the second contingency. In general, system adjustments should be completed as quickly as possible but must be completed within 30 minutes after occurrence of any contingency event. During this 30-minute time period the following actions are allowed:

1. 10 minute quick-start and reserve generation
2. Generator runback and/or generator tripping
3. Phase shifting transformers (PARs)
4. HVDC controls
5. LTC adjustments
6. Series and shunt capacitors/reactors
7. Reducing imports from external Areas

Post Operator Actions (May exceed 30 minutes)
Not all operator/field crew actions are expected to take place within the 30-minute operating window established by NPCC. Expected actions that may take longer than 30 minutes due to dispatching line crews to open/close manually operated switches, generation ramping capabilities, calling a generator online, enabling or disabling a non SCADA SPS should be taken into consideration. These conditions could last for days or weeks while equipment is repaired. The following considerations should be realized in testing the system once all expected actions should occur on the transmission system prior to a second contingency.

A) Reduction of generation (up to 1200 MW) behind a limiting interface to meet line-out interface limits
B) Restoration of load served from a transmission tap without Motor Operated Disconnects (MOD) and remote or automatic control operation.

[25] In addition to the list of single contingencies, bus faults should be considered in the planning and construction of the local transmission system. It is recognized that this is a similar scenario to faults on the BES transmission system which are generally less frequent due to increased clearance
[26] A double-circuit transmission tower outage should be a tested contingency if the multiple-circuit towers are used for more than one mile in total length. Testing for double-circuit tower contingencies may be excluded if a special tower design is constructed to significantly reduce the likelihood of lightning strikes and/or back-flashes.
[27] NPCC Directory #1 – Design and Operation of the Bulk Power System – NPCC.org
[28] ISO-NE Transmission Planning Technical Guide – ISO-NE.org
[29] NYSRC Reliability Rules & Compliance Manual – NYSRC.org

5.4 Load

Development and utilization of load information within planning studies has a large impact on results. Within each operating area (ME, NY, CT) of Avangrid the development of the loads is handled within the scope of the associated ISO and local process. To ensure that the system can handle a wide range of conditions Avangrid Transmission Planning must assess a variety of load levels. Unless otherwise required, 90/10 peak load levels are the maximum demand levels used by Transmission Planning to study Avangrid's transmission and subtransmission systems.

New England Operating Companies

All studies utilize the latest "Capacity, Energy, Loads, and Transmission" (CELT) forecast load level over the 1-10 year planning horizon to be accepted by ISO-NE. The ISO-NE develops this forecast for New England which is broken down by state and transmission owner. The CELT report also contains the capacity supply obligations, qualified capacities for the generators that participate in the market, and load demand response data. The CELT report values are updated on an annual basis. There are generally peak, intermediate, light, and minimum loads used in New England planning studies. ISO New England details their requirements for load levels to be tested by study type in the ISO New England Transmission Planning Technical Guide. The Maine Public Utilities Commission specifies their requirements for Maine jurisdictional transmission in their Safe Harbor Stipulation documentation.

New York Operating Companies

NERC TPL and other regional assessments utilize cases developed by NYISO that cover the 1-10 year planning horizon that consist of 90/10 and 50/50 load base cases. Values contained in these cases are published annually in the NYISO "Load & Capacity Data Gold Book". In some cases, the load values contained in the base case may need to be adjusted based on the local system changes.

5.5 Generation

5.5.1 Units Offline

To qualify a need under the ISO-NE "Needs Assessment" and "Solution Study," a probabilistic method is utilized to determine if any generation should be modeled offline or output reduced. For the local transmission system analysis at CMP, only one unit may be modeled offline to show the need for system improvements, per Maine PUC "safe harbor" provisions.

For studies completed in New York Avangrid considers the unavailability of a single generator in a region to be a realistic and prudent parameter to include when studying an area.

When a unit being taken out-of-service is physically correlated to another unit, such as a combined cycle plant, removing the two correlated generators is counted as one outage.

5.5.2 Renewable Generation Output

Hydro

The hydroelectric generation in CMP relies primarily upon the run-of-river flow to generate power. As such, these hydro facilities are classified as intermittent resources and therefore system studies should not rely upon their full capability. During summer months a reduced generation assumption should be applied that is derived from two or more years of historical metered data from the months of June through August. Utilizing this data, a flow duration curve will be calculated and the generation output that is exceeded approximately 85% of the time will be selected.

In addition to reviewing the summer expected output of hydro generation, the resultant high generation and low load during the spring should be analyzed. This scenario can create constraints on export and may require Corrective Action Plans. When conditions exist that create more severe conditions than study assumptions stated above, justification on the use of the conditions in planning the transmission system will be provided.

WIND

Using the same methodology for wind output as found to be a safe harbor for CMP's hydro dispatch in Docket 2011-494, the data shows a considerably high frequency of zero output for wind generators in CMP's territory. Therefore, the findings of this analysis support CMP's recommendation to model wind generators at zero output during low generation dispatch conditions. Wind should not be relied on when studying load or system reactive support.

While the data from CMP wind output shows a low frequency of full nameplate output for the wind generators, modeling this higher output can be vital in determining the limitations of the system under full output conditions. This is especially true in heavy generation export areas. Therefore, analysis should be conducted using high wind generation output levels during studies as well.

6. Interconnections & System Changes

Avangrid is governed by multiple procedures and criteria for transmission interconnections. Most of these procedures are coordinated with NERC, associated ISOs, and Avangrid. Procedures are put into place governing FERC defined Large Generator and Small Generator (T-G), transmission to load (T-L) and transmission to transmission (T-T) interconnections. These procedures and processes are developed in compliance with the applicable ISO and NERC standards such as FAC-001, FAC-002, and the Minimum Interconnection Standards (MIS).

6.1 Significant Adverse Impact

For testing of proposed load, generation, or elective interconnections/upgrades to its transmission and subtransmission systems, AVANGRID performs analyses to determine if the proposed system changes have a Significant Adverse Impact, which is defined as:

1. A change to the transmission system that increases the flow in an Element by at least two percent (2%) of the Element's rating and that causes that flow to exceed that Element's appropriate thermal rating by more than two percent (2%). The appropriate thermal rating is the normal rating with all lines in service and the LTE or STE rating after a contingency.

2. A change to the transmission system that causes at least a one percent per-unit[30] (1%) change in a voltage and causes a voltage level that is higher or lower than the appropriate pre or post-contingency limit by more than one percent.

3. A change to the transmission system that causes at least a one percent (1%) change in the short circuit current experienced by an Element and that causes a short circuit stress that is higher than an Element's interrupting or withstand capability.

[30] The change in voltage is expressed in per-unit. For example, a change from 1.045 to 1.055 would be a 1% per-unit change

4. With due regard for the maximum operating capability of the affected systems, one or more of the following conditions arising from faults or disturbances, shall be deemed as having significant adverse impact:
    - Any loss of synchronism or tripping of a generator
    - Unacceptable system dynamic response
    - Unacceptable equipment tripping: tripping of an un-faulted bulk power system element (element that has already been classified as Bulk Power System) under planned system configuration due to operation of a protection system in response to a stable power swing or operation of a Remedial Action Scheme in response to a condition for which its operation is not required

5. Loss of automatic or manual operational capability in responding to and mitigating emergent conditions. For example, a system change that prevents a circuit from being backed up from an alternate source, or being used as a backup source.

If a system change is determined to cause a Significant Adverse Impact sufficient network upgrades are required to mitigate the adverse impact

6.2 New York

Transmission Facilities owned by New York State Electric & Gas and Rochester Electric & Gas are governed by the NYISO procedures for interconnecting to the transmission system. Generators requesting to interconnect to the NYSEG & RG&E transmission system are directed to the NYISO so that they may follow NYISO's processes. Large Generator Interconnections and Small Generator Interconnections are governed by NYISO Open Access Transmission Tariff (OATT). Depending on the MW capacity of the projects, generators that interconnect outside the purview of NYISO are governed by the NYS Public Service Commission's Standardized Interconnection Requirements (SIRs) or the Avangrid's Interconnection Process (Bulletin 86-01 - Requirements For The Interconnection Of Generation, Transmission & End-User Facilities").

Similar to the generators, significant modifications or interconnection of load and Transmission Facilities to the NYSEG and RG&E facilities need to go through the applicable Procedures. Below is the high-level summary of these processes:

The Interconnection or modifications of transmission facilities to the NYISO jurisdictional transmission system are governed by either the Large Facilities Interconnection Facilities (LFIP) or the Transmission Interconnection Procedure (TIP).
Interconnection of load larger than 10 MW connecting at a voltage level ≥ 115 kV or a new load larger or equal to 80 MW at any voltage level are required to go through the NYISO Load Interconnection Procedures.
Interconnections of Load (T-L) and Transmission outside the purview of the NYISO are required to follow the NYSEG & RG&E procedures such as the Bulletin 86-01.

6.3 Central Maine Power

Pool Transmission Facilities (PTF) owned by Central Maine Power are governed by the ISO-NE procedures for interconnecting to the transmission system. Generators requesting to interconnect to the CMP system are directed towards the ISO-NE processes. Large Generator Interconnections and Small Generator Interconnections are governed by ISO-NE Schedule 22 and Schedule 23 respectively. Generators that interconnect outside the purview of ISO-NE are governed by the MPUC Chapter 324. All generators interconnections impacting transmission incorporate the CMP requirements document "Transmission & Distribution Interconnection Requirements for Generation" in an open study process.

Transmission to Load and Transmission to Transmission interconnections are incorporated into the CMP requirements document "Requirements for Connection of Non Generating Facilities to The Central Maine Power Company Transmission System." All facility modifications to the ISO-NE jurisdictional transmission system must be done with a Proposed Plan Application (PPA). This ensures review by the ISO and study within the Regional System Plan.

6.4 United Illuminating

Pool Transmission Facilities (PTF) owned by United Illuminating are governed by the ISO-NE procedures for interconnecting to the transmission system. The interconnection of generators to the UI system is handled differently depending on a number of factors including but not limited to gross output, interconnection voltage and the generator's market participation.

For the ISO-NE process Large Generator Interconnections and Small Generator Interconnections are governed by ISO-NE Schedule 22 and Schedule 23 respectively. The Connecticut state interconnection procedure is documented in the "Guidelines for Generator Interconnection" joint process between Eversource Energy and United Illuminating.

6.5 Material Generation Changes

Significant generation additions or changes may have an impact to the performance of the to the system and must be evaluated in a manner consistent with their potential impact. Avangrid follows the ISO-NE and NYISO processes in place to identify and study generation addition, changes or retirements that may be impactful.

In accordance with Requirement 2.5 of the TPL-001 standard Avangrid utilizes the following to identify generation addition or changes that may be material to the stability performance of the Bulk Electric System:

- New England Operating Companies:
  - Any generation interconnection or modification that requires a Level III study as identified in ISO-NE Planning Procedures 5-1, 5-3, and 5-6.
- New York Operating Companies:
  - Facilities participating in the NYISO Large Generator Interconnection Procedure (LGIP) or Small Generator Interconnection Procedure (SGIP) study processes.

6.6 Material Transmission System Changes

Proposed changes to load, generation, or elective interconnections/upgrades that may have an impact to the power system are routinely studied to determine if any network upgrades are required to be built to maintain system performance. Because the studies produced by these projects indicate either that 1) there was not an adverse impact to the power system, or that 2) the project will install the network upgrades to required mitigate its adverse impacts; it is generally not necessary to perform new TPL-001 study solely based on changes to the system topology.

It is important that more gradual changes, like load levels, are compared to the previously studied conditions to determine which studies can be considered as past-qualified. This review may result in determination that the changes to system load are due to one or more large loads that were already studied as part of their interconnection, or that the load growth is gradual and system-wide which would require new studies.

7. NERC Compliance Activities

Transmission Planning is regularly involved in NERC Compliance activities, many of which require retention of compliance with those standards. Long-term storage of compliance evidence is on the AVANGRID Transmission Planning Sharepoint Site and should be filed by those who generate or receive the compliance evidence.

To aid this, all e-mail traffic that is or may be considered evidence of compliance should be forwarded or copied to the shared e-mail account TPCompliance@avangrid.com where it will be periodically reviewed and filed. This guidance pertains to all compliance activity of performed by Transmission Planning but below are a examples of standards where evidence may frequently be generated or transmitted via e-mail:

- CIP-014
- MOD-032
- PRC-023
- PRC-026
- TPL-001
- TPL-007