INTRODUCTION

The overall planning process is consistent across National Grid's electric distribution operating companies in Massachusetts, New York and Rhode Island, however specific planning thresholds or limits may vary by jurisdiction to accommodate regional differences in tariffs, regulatory requirements, and differences in grid system characteristics.

PURPOSE

This document describes National Grid's Electric Distribution Planning Criteria ("Criteria") to be applied in forward looking distribution studies. These studies will generally have a planning horizon of one to ten years. The thresholds and limits presented in these criteria are intended to identify developing distribution system needs and initiate investment to achieve or improve upon service quality standards, reliability and resiliency in a safe, clean and economical manner.

APPLICABILITY

These criteria are to be applied to National Grid's electricity delivery systems below 69 kV in Massachusetts, New York and Rhode Island. Individual criterion presented within this document may be subject to change if mandated by future regulation or legislation.

The criteria described in this document shall be applied to all types of distribution planning studies conducted, including:

- Area planning/Integrated Planning studies that take a holistic look to planning[1].
- Load Interconnection studies to assess the impact of new spot loads interconnecting to the Sub-Transmission or Distribution grid systems
- Generator and Energy Storage System (ESS) Interconnection studies for both the Distribution and Sub-Transmission System to assess the impact from the interconnection of new a generator or ESS.
- Special Studies/Programs such as new technology assessments, system wide targeted programs etc.

For the small percentage of the urban underground distribution system designed as a secondary network, specific criteria and loading limitations are defined in the National Grid distribution standards.

[1] This could include whole system assessments such as an integrated transmission (Transmission Criteria would be applied), sub-transmission and distribution system studies and geographically bound area studies.

ACCOUNTABILITY

The Distribution Planning and Asset Management (DPAM) department is responsible for performing the needs assessments and developing recommended solutions to achieve the defined objectives.

COORDINATION

The application of load and DER forecast scenarios, equipment ratings, and this Criteria must be well coordinated to manage risks on the distribution system.

REFERENCE DOCUMENTS

- PR.30.10.011 DEMAND SCENARIOS & FORECASTS
- PR.30.10.012 DEVELOPMENT OF CAPACITY & UTILIZATION MEASURES
- PR.30.10.013 STRATEGIC PLANNING FRAMEWORK
- PR.30.10.014 DEVELOPMENT OF PLANNING SCENARIOS
- PR.30.60.001 ASSET HEALTH FRAMEWORK (IN DEVELOPMENT)

Contents

1.0 DEFINITIONS

- Sub-Transmission is 46 kV to 23 kV grid systems and Distribution is 13.8 kV to 4.16 kV.[2]
- Distribution transformers connect the Distribution grid to the Transmission Grid or Sub-transmission grid.
- Sub-transmission transformers[3] connect the Sub-Transmission grid to the Transmission grid.
- Electrical Grid – "grid"
- Service transformer – a transformer that connects a Distribution voltage to a customer voltage e.g. 240/120 V
- Continuous (in relation to Ratings) is an all hours limit.
- Delta-V – Voltage instantaneous step change typically caused by line switching or capacitor bank switching.

2.0 ACRONYMS

- UPNY – Upstate New York
- NE – New England
- DPAM – Distribution Planning and Asset Management
- NWA- Non-Wire Alternative (typically consists of DER systems)
- DG – Distributed Generation
- ESS – Energy Storage System
- ESB – Electric Service Bulletin
- DER – Distributed Energy Resource (includes Energy Efficiency , Energy Storage, Distributed Generation and Demand Response)
- EE – Energy Efficiency
- DR – Demand Response
- LTE – Long Term Emergency
- STE – Short Term Emergency
- CI - Customers Interrupted
- CHI - Customer Hours Interrupted

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[2] Some 34.5 kV systems in NE are operated as Distribution systems and some 2.4 kV delta systems are operational in NE. 12 kV in Niagara is operated as 12 kV Sub-Transmission and listed as FERC Transmission.

[3] This definition is for planning purposes only. For budgeting, a transformer is either a FERC distribution or transmission defined asset.

- ISO-NE – Independent System Operator New England
- NYISO – New York Independent System Operator
- MA – Massachusetts
- NY – New York
- RI – Rhode Island
- CAIDI - Customer Average Interruption Duration Index
- SAIFI - System Average Interruption Frequency Index
- SAIDI - System Average Interruption Duration Index
- RFP – Request for Proposal
- PCC – Point of Common Coupling
- ANSI – American National Standard Institute
- CVR – Conservation through Voltage Reduction

3.0 DISTRIBUTION PLANNING CRITERIA

3.1 Load and DER Forecasting

Area planning / Integrated[4] Planning studies will consider a 10 year forward horizon, unless otherwise stated in this Criteria document or as required for special studies.

Forecasts shall be generated for multiple scenarios of weather, DER, EVs, base load and electrification of heat. Probabilities of occurrence for each scenario shall be developed, whereby weather forecasts shall include a 50/50, 90/10[5] and 95/5 probabilities. For distribution planning the 90/10 scenario will be applied.

Multiple DER forecast adoption scenarios shall be provided with associated probabilities of occurrence. Each year DPAM management shall review the forecasts provided and select the appropriate probabilities of occurrence for each scenario, for application to all planning studies, while keeping risks and economics in mind[6].

Granular bottoms-up[7] or top-down[8] zonal forecasts maybe applied to planning studies, however there must be consistency between them. Both peak load and day-time minimum load scenarios shall be assessed[9].

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[4] Examples include studies that factor DERs as wire solution alternatives i.e. NWA studies, and integrated Transmission and Distribution studies
[5] For example, the 90/10 forecast is a set of weather conditions that is not expected to be exceeded but one year out of ten
[6] Special studies maybe an exception
[7] Forecasts developed from localized customer variables such as adoption modeling
[8] Forecasts developed from bulk grid view of forecasts such as from ISO's
[9] Higher resolution studies maybe applied for special studies, such as 8760 hour analysis

3.2 Application of Asset Ratings

Thermal asset ratings define the limits to which a grid asset can be safely operated without causing damage or reduced service life. Asset ratings are determined in accordance with applicable ANSI/IEEE standards, manufacturer's guidance and good utility practices. Transformer ratings shall be developed in accordance with the latest versions of National Grids Equipment Ratings Guide and Transformer Loading Guide.

Distribution Planning maintains asset and circuit ratings, that vary by season, for normal operation as well as for contingency response. The ratings used in planning are referred to as Summer Normal, Winter Normal, Summer Long Term Emergency (LTE) and Winter LTE.

Normal ratings are intended to be routinely applied and assume a typical daily load cycle[10]. The LTE ratings are intended to be applied for contingency conditions and their use is limited to 24[11] hours per occasion. In extreme cases, system operators may choose to apply a short-term emergency (STE) rating for contingency loading of shorter durations, however STE ratings shall not be used for planning purposes.

Summer ratings are applicable from May-October[12] and winter ratings from November-April.

3.3 Thermal Loading

Distribution Planning recommendations shall be developed to reduce loading on an asset or circuit when load is forecasted to exceed 95%[13][14] of either summer or winter normal ratings during non-contingency operating periods.

3.4 Voltage

The nominal and emergency voltage to all customers shall comply with limits specified by state regulators and/or within the limits of ANSI C84.1 for both normal and abnormal (N-1) conditions. For conservation voltage reduction efficiencies, National Grid endeavors to operate at the lower levels of the allowable voltage ranges presented in Table 1.

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[10] Individual ratings based on individual historical load cycles shall be developed for transformers that are projected to be overloaded

[11] NYISO and ISO-NE apply these ratings as a 4-hour ratings

[12] Operations may apply alternate ratings on a summer period for days with temperate below the ambient rating

[13] Under certain circumstances NYISO and ISO-NE requirements may supersede this value

[14] As an exception distribution generation and energy storage interconnection projects will be studied to a 100% limit

Table 1 - Voltage Requirements by State

State	Upper	Nominal	Lower
Massachusetts	126	120	114
New York	123[15][16]	120	114
Rhode Island	126	120	114

Voltage limits for Sub-Transmission systems in UPNY shall follow Table 2 below. Sub-transmission systems in NE shall follow the distribution voltage thresholds above.

Table 2 - UPNYISO Sub-Transmission Voltage Limits

Voltage Planning Criteria	
Voltage Limit	
Pre-contingency High	105% Nominal *
Pre-contingency Low	95% Nominal *
Post-contingency High	105% Nominal *
Post-contingency Low	90% Nominal *
Maximum Pre to Post-Contingency Change**	10% *
Maximum Switching Change for Normal Conditions	4%
Maximum Switching Change Following Single Contingency	7%
Notes	
* LTC operation, reactive compensation changes, and dispatch changes allowed	

Voltage flicker limits shall follow the IEEE 1453:2015 standard and voltage fluctuations due to capacitor switching and other regularly occurring operations on the distribution system shall not exceed a 3% delta-V.

[15] An exception is for DG interconnections that allows up to 126 volts at the PCC and per ESB 320 126 volts can be held if a capital project would otherwise be required to maintain at 123 volts

[16] The 123 volts upper limit is a NY only requirement from a Commission Order 02-E-1240 regarding implementation of the ANSI C84.1 standard and associated CVR direction from the Commission

3.5 Contingency Response (N-1[17])

In order to successfully plan the grid, planning for potential grid asset outages is vital. This criterion captures limits to the number of customers that can be interrupted in alignment with company's reliability targets, while keeping the remaining grid within voltage and thermal limits to maintain safety and prevent any damage.

The following N-1 asset outages shall be evaluated:

- Distribution Feeder
- Distribution transformer
- Sub-transmission transformer
- Sub-transmission line
- Distribution suppled Transmission line
- Largest downstream generator or ESS[18]

To determine the number of customers at risk of outage for the duration of repairs the following operational response is assumed:

- Load transfers[19] are initiated to adjacent circuits with available capacity
- Any managed DER[20] resources are activated in accordance with contract terms
- For loss of substation transformer events roll-in mobile substations are be in service within 24 hours post contingency

During an N-1 contingency condition the following criteria apply:

- Equipment loading shall not exceed 100% of the applicable summer or winter LTE rating.
- Equipment loading will be reduced to below 100% of the applicable summer or winter normal rating within 24 hours of the contingency event.[21]

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[17] Where N = the grid with all assets in service, N-1 is therefore the loss of one single asset i.e. a substation transformer.
[18] Loss of largest downstream generator or ESS shall be studied as an N-1 contingency and appropriate mitigations developed as necessary
[19] Load transfers shall be modeled with any DG and ESS connected to the transferred feeder segment, modeled offline post load transfer i.e. DG auto-reconnection scheme disabled.
[20] Examples include NWAs, Demand Response etc.
[21] Loading shall return to no more than 95% loading of either summer or winter normal ratings when the system is returned to normal configuration.

- Feeder ties within the area can be utilized up to 100% of the applicable summer or winter LTE rating for up to 24 hours

If the load transfers and activation of any managed DER resources are insufficient to restore service to all customers in advance of repairs or temporary installation of a mobile substation. Then the number of customers interrupted required to maintain the remaining grid within voltage and thermal limits must be assessed. If the Customers Interrupted (CI) count (see Table 3) or Customer Hours Interrupted (CHI) count (see Table 4), exceeds the Post Load Transfer[22] thresholds in the tables below, planning recommendations to bring the counts below the thresholds shall be made.

Table 3 - Regional Post Load Transfer CI Limits for the loss of a Transformer, Sub-Transmission line or Distribution Supplied Transmission line

Post Load Transfer CI Limits		
Area	**15 kV+ Class Substation & Sub-Transmission**	**5 kV Substation**
MA	2600	1000
NY	2900	600
RI	2500	800

[22] Average load transfer capabilities are assumed to have occurred prior to these limits i.e. the limits are applied to customers remaining out of service after load transfers have occurred

Table 4 - Regional CHI[23] Values for N-1 Feeder Outage per kV Class per Year[24]

Post Load Transfer CHI Limits									
Voltage Class	**MA 2021**	**MA 2022**	**MA 2023**	**MA 2024**	**NY 2021**	**NY 2022**	**NY 2023**	**NY 2024**	**RI 2021-2024**
35 kV[25]	2860	2530	2220	1920	N/A	N/A	N/A	N/A	2860
15 kV	2082	1895	1700	1515	3046	2400	1900	1300	3117
5 kV	1056	1002	945	891	1275	1020	820	520	824

3.1 Consideration of Non-Wires Alternatives (NWA)

As DER becomes more prevalent and control schemes advance, the Company will consider DER solutions as alternatives to traditional wire-based investments in developing the most beneficial solution for customers to address capacity and reliability needs per the following criteria shown in Table 5 below.

If an NWA solution passes these screening criteria, an in-depth analysis will be performed that may lead to an RFP soliciting third party solutions.

NWA design parameters should consider the limits established in Planning and Operations Criteria. e.g. sizing to maintain thermal and voltage limits within Normal Operating conditions for the defined duration of need

Table 5 - NWA Criteria

Criteria	New York and Massachusetts	Rhode Island
Project Type Suitability	Project types include Load Relief and Reliability. Other types have minimal suitability and will be reviewed as suitability changes due to State policy or technological changes.	Project types include Load Relief and Reliability. The need is not based on Asset Condition. If load reduction is necessary, then it will be less than 20% of the total load in the area of the defined need.
Timeline Suitability	Start of construction is at least 18 months in the future.	Start of construction is at least 30 months in the future.
Cost Suitability	Greater than or equal to $500K	Greater than $1M

[23] A period of four hours can be assumed from the time of the N-1 event to completion of repairs and full feeder restoration. However, other time periods maybe applied with knowledge of local operational capabilities

[24] Reduction in limits over the years are set to match the MA Glide Path and to drive towards alignment with NY reliability targets

[25] Only applicable in NE as NY does not operate any 35 kV as radial distribution

3.2 Fault Duty

Fault levels shall remain below the interrupting rating of protection devices and current limiting ratings of all other assets in accordance their manufacturer specifications and the Company's Standards at all times.

3.3 Protection Analysis

Protection and coordination analyses should be performed for all distribution substation and mainline protective devices during a distribution system study. The four objectives listed below should be considered to identify potential issues. Maintain a safe and reliable distribution system Minimize the number of customers impacted for a given fault condition. Protect distribution assets from damage due to fault current Aid in locating faults and thereby reducing restoration times.

The analyses should be performed for the existing system as well as for proposals of new system configurations. Specific guidelines for protective device settings and operating targets (i.e. clearing time, coordinating time intervals) can be found in Engineering Document GL.01.01.001.

3.4 Arc Flash

An Arc-flash study shall be conducted on a regular basis and updates made when significant changes to the system occur. If it is determined that the incident energy levels will exceed the personal protective equipment ratings currently required at that location the appropriate safety and operating departments must be informed. Please refer to the National Grid Planning Guidelines for Arc Flash Awareness and Potential Mitigation document for more details.

3.5 Reliability

Reliability is one of the key KPI metrics by which the company's performance is assessed. The metrics of SAIFI, CAIDI, and SAIDI are continuously monitored and reported. These metrics measure the "average" performance on an annual basis. While the planning criteria is intended to achieve the targeted reliability performance in aggregate, additional planning efforts are focused on targeted distribution[26] circuits that have performed poorly in recent years. In each state, distribution planners shall develop, prioritize and assess the worst performing feeders based on a five-year historical average total number of customer hours interrupted metric and develop action plans to improve the performance of the top 5% worst performers.

[26] Supply lines that do not have customers directly connected to them (connected only with a protective device such as a recloser) are excluded

3.6 Resilience

Major storm impacts are omitted from reliability metrics in accordance with state specific requirements. As storms become more frequent and severe considering recent trends and expected climate change impacts, more focus is to be given to the resilience of the grid to withstand and recover from more extreme events.

The following criteria should be considered when the Company is planning feeder or substation upgrades of greater than $1 million.

A resiliency project shall be developed for 15 kV class and above lines and stations that have one or more protection devices with a total ten year historical CHI event outage value of greater than the CHI Outage Limits specified in Table 6 below for events lasting greater than 24 hours.

Table 6 - CHI Outage Limits for Ten Years per region

MA	NY	RI
156,000	50,100	113,400

A station flood mitigation analysis shall be conducted for stations that are within the 100-year flood zone, whereby the area planner will consult with Civil Engineering to determine the possible flood water levels, asset at risk and potential mitigation measures. This risk will be compared against the costs of the alternatives to determine if a project is required.

3.7 Reactive Power

Improving power factor through reactive support helps regulate voltage and can release capacity to be utilized for power delivery. Reactive power mitigation is considered a low-cost solution to reducing loading, losses and improving voltages.

Substation reactive support criteria

Reactive compensation shall be required for substations with system loading above 95% of either summer or winter normal ratings[27]. These should be sized to offset the reactive losses of the transformers at forecast peak load[28].

Substations in NE shall maintain unity Power Factor at the high-side bus as practically possible to meet ISO-NE requirements always of the day over the year.

[27] Feeder reactive compensation criteria should be addressed prior to sizing transformer reactive loss compensation

[28] Station reactive compensation should address transformer reactive losses only.

Sub-transmission reactive support criteria

The planner should look to mitigate thermal or voltage violations through reactive compensation measures placed on effectively grounded lines or at a customer or Company substation.

Feeder reactive support criteria

Reactive compensation shall be provided for 15 kV class feeders if the reactive power consumption at the feeder station breaker is > 450 kVAR[29] (3 phase) during peak load and the feeder loading is greater than 85% of the summer or winter normal rating.

3.8 Load Balancing

It is good practice to maintain equal phase current balance on feeders, transformers and transmission systems to limit ground current, voltage differences (i.e. induction motor heating) and minimize losses. However, in practice achieving 100% balance is difficult due to the preponderance of single-phase loads on the distribution system. As part of distribution studies, opportunities to improve phase balancing should be considered when:

- A feeder has a calculated neutral current exceeding 30% of the feeder ground relay pickup setting
- The difference between phase current exceeds 100A between the high and low phases
- Where the imbalance exacerbates another criteria issue, such as a thermal overload or voltage problem

3.9 Transmission and Distribution Alignment

Notification shall be given to Transmission Planning any time there is a proposed load, generation or ESS incremental change[30] in aggregate greater than 20 MW[31] downstream of a station transformer occurring within a prior 6-month period and/or a new substation is proposed by Distribution Planning and/or a transformer upgrade that increases the bank size.

3.10 Hosting Capacity

As state governments and the Company encourage a cleaner grid and setting future targets for renewable DG, and in-particular solar PV, grid constraints such as thermal, voltage, fault and protection limits, become a significant limiting factor to growth of these technologies. To address this challenge consideration of projects that increase hosting capacity become more important in achieving these targets.

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[29] Study should be based on actual peak load reactive power recordings from PI and should have existing installed VAR support devices enabled

[30] Based on interconnection (DG, ESS and load) requests received during that prior 6-month period

[31] ISO-NE requirements are 5 MW for study and 1 MW for modeling

NE:
For New England both criteria below are conditional upon a separate violation of a planning criteria element, i.e. load relief, reliability, asset condition etc., and that a resulting hosting capacity project that resolves the violation does not result in any increased cost to the load relief, reliability, asset condition etc. capital project.

UPNY:
For NY both criteria below are conditional upon a separate violation of a planning criteria element, i.e. load relief, reliability, asset condition etc. regardless of cost impact.

Substation Hosting Capacity Criteria: a station project to increase hosting capacity shall be proposed for stations that are forecasted to be thermally overload due to DG[32] within the next 5 years and/or for substations that do not have transformer high-side[33] single phase ground fault detection (3V0), when the 5th year DG MW forecast[34] is greater than 67% of the station 5th year forecast minimum gross[35] MW load with the highest loaded feeder out of service.

Feeder Hosting Capacity Criteria: a feeder project to increase hosting capacity shall be proposed when the 5th year DG MW forecast is greater than the weighted average feeder MW hosting capacity[36].

3.11 Interconnection Studies

All interconnection studies, i.e. load, DG, ESS etc., shall be conducted in accordance to the latest ESB series of standards and with consideration of Guidelines i.e. GL309B.

3.12 Network criteria

Secondary network criteria and loading limitations are defined in the National Grid distribution UG Construction Standard Section 42.

3.13 Asset condition criteria

Asset condition shall be assessed based on the documentation and processes developed from the associated Asset Management workstream effort as they become available and approved for use. Please see PR.30.03.02.08 Decision Making Guideline.docx.

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[32] Any proposed station hosting capacity projects should be discussed with Transmission Planning to verify there is available transmission hosting capacity
[33] For transformers with high side delta only.
[34] Based on approved DG forecast determined by DPAM management on year cadence
[35] Unmasked load
[36] The average hosting capacity shall be based on the latest hosting capacity analysis results available at the time and inclusive of the forecast 5th year gross load. Weighted average should capture the variance in hosting capacity values along the length of the feeder mainline.

4.0 REVIEW

This document should be reviewed every two years and updated as necessary.

5.0 REVISION HISTORY

Issue	Date	Author(s)	Approved By	Description of Revision
1	2/15/2011	Curt Dahl, Max F. Huyck, Jeffery Smith	Patrick Hogan	First version
2	3/30/2021	David Lovelady & Ryan Constable	Carol Sedewitz	Major update