TM 1.61.00 Avangrid Distribution Planning Criteria

Planning & Coordination

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AVANGRID

Revision History

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01	11/2023	Corrected minor errors throughout document, clarified various areas. Updated Non-Wires Alternatives section to include Non-Wires Solutions process established in Connecticut, and further define process in Maine and New York. Added a sub-section for Study Assumptions. Added Appendix 4 for Load Diversification Factors.	Planning

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1. Introduction

This document describes the criteria to be applied as part of the electric distribution planning process (Distribution Planning Criteria) by Avangrid's Operating Companies (OpCos) which include New York State Electric & Gas (NYSEG), Rochester Gas and Electric (RG&E) in New York; Central Maine Power Company (CMP) in Maine; and The United Illuminating Company (UI) in Connecticut. This document defines the guidelines to plan the distribution system to ensure safe, reliable and cost-effective electric service to Avangrid customers. The criteria recognizes that thermal and operating limitations exist for the normal and contingency operation of the system, as well as the necessity of maintaining a proper balance between service reliability and the cost of providing that service. The criteria also recognizes that system design should account for future load growth, distributed energy resource (DER) interconnection and hosting capacity.

All electric power distribution facilities shall be designed using prudent engineering judgment, in accordance with good industry practice, and shall conform to all applicable Avangrid and industry standards, as well as regulatory requirements. This document is intended to be the basis of, not a substitute for, Company Distribution Safety Policies and Procedures, Terms and Conditions for Service, Construction Standards, and other Distribution Engineering Guides. Construction of all overhead and underground distribution systems will be performed in accordance with currently approved construction standards and using currently approved materials.

This document shall be reviewed every six months and revised as necessary by the Distribution Planning Criteria Review Committee to reflect any major standards or criteria changes.

1.1 DISTRIBUTION SYSTEM DESCRIPTION

Avangrid's distribution system is comprised of lines and equipment operated at a medium voltage of 34.5 kV and below. The OpCos utilize different medium voltage levels ranging from 2.4 kV to 34.5 kV. The distribution systems supplied by these primary voltages are either multi-grounded wye connected or delta connected primary systems. Additionally, circuits in NYSEG, RG&E and CMP territory that supply distribution substations as well as distribution customers should abide by the Distribution Planning Criteria. Avangrid does not allow the creation of new Transmission taps that feed distribution customers. The territory served by the OpCos is composed of urban, suburban and rural areas. Urban areas include the Cities of Bridgeport and New Haven in CT, Binghamton and Rochester in NY, and Portland in ME. Suburban areas include the towns surrounding the major urban cities. CMP and NYSEG serve large rural areas in Maine and Upstate New York respectively.

The majority of the distribution system load is supplied via conventional overhead radial distribution with poles and overhead conductors as well as with some conventional underground radial supply in urban and suburban areas. In addition, the downtown areas of New Haven & Bridgeport in CT; Binghamton, Rochester and Auburn in NY; and Portland in ME are supplied by underground Secondary Network Systems. A Secondary Network System consists of an urban underground electrical system which supplies customers typically at 120/208V. These systems typically consist of four to ten primary cables, transformers, secondary and service cables, and switching equipment. The secondaries of all transformers are interconnected and protected by fuses and network protectors so that a first contingency outage of any secondary cable will not cause an outage to another portion of the network. The protection ensures

that a first contingency outage to any primary portion of the network will not cause a customer interruption.

Spot secondary networks are used in areas to serve specific large loads in urban areas. Some of these are served at 120/208V, while others are served at 277/480V. Typically, two to three supply feeders are used to serve the spot networks.

Appendix 1: Avangrid Operating Companies Characteristics as of 2022 provides additional characteristics and statistical information for each OpCo.

2. Power Quality Criteria

2.1 SERVICE VOLTAGE CRITERIA

The nominal system and service voltages for all Avangrid OpCos shall conform with the standard nominal system voltages established by the most recent version of the American National Standards Institute (ANSI) Standard C84-1 Range A and Range B. *Alternating current service under normal conditions shall be supplied at 60 cycles per second and under normal conditions shall not have a deviation in excess of +/-0.5 Hertz.*

Under normal conditions, Avangrid distribution systems should be designed and operated to comply with service voltages within the Range A limits. *The steady-state service voltage in Range A should remain within the bandwidth of 0.95 to 1.05 per unit or +/- 5% of nominal (126V/114V on a 120V base).*

For utilization voltage, end user equipment should be designed to operate effectively and to provide full performance within the limits of Range A service voltage. The tolerance for Range A utilization voltage is +5% to -10% (126V/108V on a 120V base). Utilization voltages are generally considered to be the voltage at the terminals of the device or appliance or the voltage at the convenience outlet to which these terminals are connected. This voltage is the customer/facility's responsibility to maintain within the acceptable limits.

Voltage occurrences outside of Range A, but within Range B are allowable but should be limited in frequency and duration such as during a contingency. *The service voltage limits for Range B are +6% / -8% (127V/110V on a 120V base).* When voltage variations occur beyond Range A on a sustained or frequent basis, corrective actions shall be undertaken within reasonable time to improve voltages to meet Range A requirements. The figure below shows the voltage levels for ANSI C84.1 Ranges A and B on a 120V base.

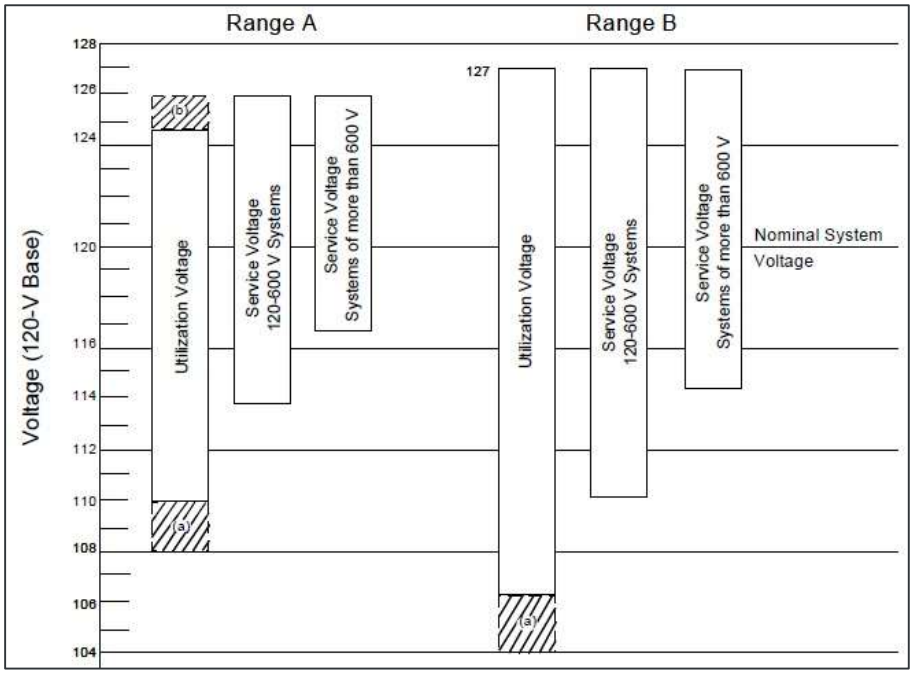


Figure 1: ANSI C84.1 Voltage Ranges

Please note that these limits apply to sustained voltage levels and not to momentary voltage variations including switching operations, fault events, and motor starting currents.

Voltage is regulated by load tap changing equipment at the substation (transformer Load Tap Changers [LTCs] or substation regulators), field regulators, and capacitor banks to follow changes in load. These voltage changes are typically small incremental steps required to keep the service voltage within acceptable limits as load changes throughout the day.

2.2 VOLTAGE IMBALANCE

Voltage imbalance and the resulting current imbalance can create excessive heat that may damage motor loads. *Electric supply systems should be designed and operated to limit the maximum voltage imbalance to 3 percent when measured at the electric-utility revenue meter under no-load (N.L.) conditions; in compliance with the American National Standards Institute (ANSI) C84.1 entitled "Electrical Power Systems and Equipment – Voltage Ratings (60Hz)".*

Voltage imbalance of a polyphase system is expressed as a percentage value and calculated as follows:

$$Voltage\ Imbalance = \frac{Max\ Deviation\ from\ Avg\ Voltage}{Avg\ Voltage} * 100$$

Example: With Phase-to-Phase voltages of 230, 232, and 225, the average is 229; the maximum deviation from the average is 4; and the percentage of imbalance is (100x4)/229 = 1.75 percent

2.3 VOLTAGE CHANGE / FLICKER

Flicker can be described as an effect resulting from voltage changes occurring in rapid succession with large enough magnitudes to cause sudden variations in the intensity of lightning which may be noticeable to the human eye. The severity of flicker is a function of both the frequency and magnitude of voltage fluctuations.

Fluctuating loads such as motor starting, welding, and other large intermittent loads can cause voltage dips and voltage flicker. ***Voltage flicker is considered excessive if it exceeds 3%.*** Equipment contributing to excessive flicker shall be investigated to determine if corrective actions are required.

2.4 HARMONIC LIMITS

Certain types of loads produce currents and voltages with frequencies that are integer multiples of the 60 Hz fundamental frequency. These higher frequencies are a form of electrical pollution known as power system harmonics. The most common sources of harmonics are power electronic loads such as adjustable speed drives (ASDs) and switching power supplies. While in most cases, the effects of harmonic distortion on electric equipment at other customer locations is insignificant, certain customer equipment such as motors and transformers may be adversely affected. ***Therefore, harmonic distortion shall not exceed 3% for any single frequency or 5% total harmonic distortion and shall not injuriously affect Avangrid's equipment or service to other customers.*** This criterion is from the IEEE 519 Standard Recommended Practices for and Requirements for Harmonic Control in Electrical Power Systems. Devices contributing to excessive harmonics should be investigated to determine if corrective actions are required.

2.5 LOAD IMBALANCE

Load imbalance on the distribution system can result from unequal system impedances, unequal distribution of single-phase loads and/or asymmetrical three-phase equipment such as three-phase transformers with delta connections. Load imbalance gives rise to return current though neutral conductor which contributes towards additional losses. Distribution Planning seeks to address load balancing issues to reduce technical losses.

A distribution circuit should be assessed for load balancing solutions when the most heavily loaded phase exceeds the average phase loading by over 15% or if phases are unbalanced by more than: 25 Amps for circuits at 35 kV class[1]; 50 amps for circuits in the 15 kV class[2]; and 100 Amps for circuits in the 5 kV class[3]. This should be determined and analyzed at the feeder head-end and monthly trends should also be noted.

2.6 POWER FACTOR CORRECTION

The power factor of the distribution system is affected by the type of customer load. The majority of residential, commercial and industrial loads are inductive and operate at a lagging power factor. Low lagging circuit power factor increases system technical losses. ***A minimum Power Factor of 97% lagging shall be maintained at the substation bus for all Avangrid OpCos****. Circuit level power factor should be maintained at a level as close to unity as possible or slightly lagging.*

[1] *35 kV class includes 34.5 kV*
[2] *15 kV class includes 13.8 kV, 13.2 kV, 12.47 kV, 11 kV*
[3] *5 kV class includes 4.16 kV and below*

Field (pole mounted or pad mounted) capacitor banks may be utilized to correct power factor. ***All new installations should utilize communications-enabled switched capacitor banks.*** Control settings are determined by distribution planning based on the specific load characteristics at the installation location. Control schemes include, but are not limited to: supervisory control, time clock, voltage, kVAr, zero crossing, and temperature switching point. Volt/VAR optimization schemes may also be utilized to optimize and control power factor, especially on feeders with high concentration of DERs.

Fixed capacitors may be installed in situations where continuous reactive support is required, or where switching events violate Avangrid flicker criteria.

3. Substation & Circuit Planning Criteria

3.1 NORMAL THERMAL ASSESSMENT (N-0)

Substation/transformer bank and circuit loading should be analyzed based on established normal ratings with respect to the applicable season (e.g., summer[4] or winter[5]). Loading analysis should consider peak loading levels (summer or winter). During normal loading conditions (N-0) substations and circuits shall remain within their normal ratings at all times. The normal rating of a substation/transformer bank and distribution feeder is the peak load the asset can carry for a 24-hour load cycle under system intact (N-0) conditions without exceeding the rating for any equipment. Circuit level contingency ratings can be used for an 8-hour load cycle. Substation transformer contingency or Long-Term Emergency (LTE) ratings are either 4-hour or 12-hour.

3.1.1 SUBSTATION PLANNING CRITERIA

Avangrid substations may be capacity limited by any piece of equipment but typically are limited by the thermal rating of the transformer. Transformer normal rating is defined as the rating, adjusted for ambient conditions, which will allow maximum equipment loading without incurring loss of life above design criteria. Avangrid's methodology for rating substation transformers is based on IEEE C57.12.00.

According to Avangrid's Guideline for Substation Configuration (TM 2.00.01):

- *All new load serving medium voltage distribution substations should be built to accommodate two transformers.*
- *The number of transformers installed at a given time will be determined by the Substation's N-1 solution.*
- *Substations with multiple transformers shall be designed with a bus tie.*
- *The total loading on a substation with multiple transformers should not exceed the LTE rating of the smallest (lowest rated) transformer.*
- *All new substation transformers shall be equipped with Load Tap Changers (LTC).*

New substation design (transformer size and number of circuits) should also consider potential for high levels of DER hosting capacity in the area.

[4] *Summer is defined from June through September*
[5] *Winter is defined from December through February*

TM 2.00.01 provides additional details and criteria for substation design.

A threshold of 90% should be used for transformer normal rating to actual loading (by unit if 3-single transformers) to flag a capacity needs assessment. This value is used to mitigate a potential overload if major substation work is required which typically take multiple years to complete.

Circuit level load transfers should be given priority as a potential solution to address capacity needs at a substation. Non-Wires Alternatives (NWA) should also be considered as potential solutions to address substation capacity needs where applicable. Applicability of NWA solutions should be evaluated in accordance with the requirements established for the respective OpCo. However, when load transfer options are exhausted and NWA solutions are not technically feasible, major infrastructure projects may be required. These infrastructure projects may include new feeders, construction of a new substation or significant substation expansion which typically require significant time from proposal to completion. These projects may require regulatory applications and hearings, complex design, long equipment lead time, and land purchase. The year of need or required in-service date should be based on the load forecast for the area. System solutions selected for implementation should maintain capacity margins at the substation to a minimum of 10%.

3.1.2 DISTRIBUTION FEEDER PLANNING CRITERIA

Distribution circuits should have suitable ties to adjacent circuits to restore service to customers during faults or for planned maintenance periods. Circuits originating from substations with multiple transformers and buses should have ties to other circuits from a different bus or different area substation.

System modifications or voltage conversions should be recommended to eliminate "islands" where circuits of certain voltage level have no backup circuits in the area. The goal for all Avangrid OpCos is to standardize on a medium voltage level as much as feasible and eliminate step-down banks and lower voltage levels to reduce losses and increase DER hosting capacity.

Customer counts per circuit should be limited to 2,000 - 2,500 on 15kV class distribution and 2,500 - 3,000 on 35kV class distribution for every OpCo in order to reduce the impact of outages and system reliability.

A threshold of 90% should be used for circuit normal rating to actual loading to flag a capacity needs assessment. This value is used to mitigate a potential overload if major circuit work is required which may take multiple significant time to complete.

Circuit level load transfers should be given priority as a potential solution to address capacity needs. NWA solutions should also be considered as potential solutions to address circuit level capacity needs where applicable. However, when load transfer options are exhausted and NWA solutions are not technically feasible, major infrastructure projects may be required. These infrastructure projects may include reconductoring and/or construction of new feeders. The year of need or required in-service date should be based on the load forecast for the area. System solutions selected for implementation should maintain load capacity margins at the circuit to a minimum of 10%.

Avangrid circuits may be rated or limited by underground cable, open wire, or a piece of equipment (i.e., voltage regulators, reclosers, or switches). The majority of Avangrid's circuits are limited by either underground cable in the substation getaways or by open wire conductors. The normal ratings for underground cable and open wire are provided by Avangrid Distribution Overhead Conductor Wire and Cable Ratings (DEG 5.2) and Avangrid Distribution Underground Cable Ampacities (DEG 10.3) Standards.

New circuit overhead construction shall follow DEG 5.0 Electric Distribution System Overhead Design. Tree Wire (TW) or spacer cable construction should be used for new construction. Bare aluminum (AL)

primary wire shall only be used in areas where tree encroachment is not possible. The conductor sizes to be used for overhead construction are:

- *1/0 AWG AAAC (laterals)*
- *4/0 AWG AAC (laterals)*
- *336.4 kcmil AAC (Mainline for CMP, NYSEG and RG&E)*
- *397.5 kcmil AAC (Mainline for UI only)*
- *477 kcmil AAC (Mainline for CMP, NYSEG and RG&E)*
- *500 kcmil AL Aerial Cable w/ CU tape shields (15 kV)*
- *750 kcmil AL Aerial Cable w/ CU tape shields (35 kV)*

For new underground construction the following should apply:

- *750 KCM CU EPR or 500 KCM CU EPR for substation getaways*
- *#2 AL/CU EPR, 1/0 AL/CU EPR or 4/0 AL/CU EPR for cable laterals or Underground Residential Distribution (URD)*

New URDs should be designed with a backup feed and should be constructed in conduit, direct buried cable construction should be avoided where possible.

3.2 CONTINGENCY (EMERGENCY) RATING ASSESSMENT (N-1)

N-1 contingency planning requires that adequate back-up capability is established for the single loss of any major distribution system equipment[6]. This criterion ensures that an alternative supply is available in the event of a distribution outage or fault condition to improve system restoration time and system reliability.

N-1 contingency planning will utilize and design to summer and winter contingency or Long-Term Emergency (LTE) ratings for all equipment. Contingency or Emergency ratings exceed normal ratings and involve loss of life or loss of tensile strength in excess of design criteria.

Distribution N-1 contingency planning will be analysed in three separate categories or levels: (1) radial transmission, (2) substation, and (3) distribution circuit. Where possible, adequate circuit ties can be a common solution to establish acceptable N-1 back-up capability for all three categories.

A more detailed description of each N-1 planning category is included in the following sections.

3.2.1 SCOPE OF CONTINGENCIES

Avangrid considers the following elements as applicable single and independent contingencies during N-1 planning:

- Radial Single Transmission Line
- Substation Transformer
- Distribution Circuit

[6] *Consideration of a radial transmission supply is also included during N-1 contingency planning of the distribution system*

- Critical Generating Facility
- Shunt Device

3.2.2 N-1 CONTINGENCY OF A RADIAL TRANSMISSION OR SUB-TRANSMISSION SUPPLY LINE

When analyzing the N-1 back-up capability at a circuit and/or substation, the transmission supply should be evaluated for redundancy as well. If the substation has more than one transmission supply, then no further consideration is needed. However, if only a single transmission supply is available (single point of failure), then incremental N-1 solution alternatives should be considered that could provide back-up to the full substation in the event of a transmission outage.

Establishing full distribution circuit-tie capability to a neighboring substation that's supplied from a different transmission source could be a viable solution alternative for N-1 radial transmission deficiencies.

Providing full back-up capability to distribution substations with a single transmission supply could become cost-prohibitive; this will be reviewed and determined on a case-by-case basis. Transmission Planning should be consulted when analyzing these scenarios.

3.2.3 N-1 CONTINGENCY AT SUBSTATION

Substations with only one transformer should have adequate circuit field ties to other area substations to permit switching of all affected load to other area substation until a spare transformer or suitable mobile battery storage is installed. Substations with multiple transformers, common voltage, and bus tie capability should consider the loss of one transformer at a time and verify that the other transformer(s) can pick up the load. Therefore, the total substation coincident peak load shall be no greater than the LTE rating of the smallest substation transformer in this case. Substations with multiple transformers and no bus tie capabilities should be considered as separate electrical systems and require circuit field ties to back up the load from other substations.

When analyzing the N-1 back-up capability at the substation level, the following factors apply:

- For two transformer substations (same distribution voltage), the total distribution coincident peak load should be no greater than the LTE rating of the smallest substation transformer.
- For the loss of the transformer in an existing single transformer substation, the distribution circuits must be designed with tie capabilities to permit switching of all affected load to other area substations until a suitable mobile or spare transformer is installed.

  If adequate circuit ties can't be established, then other solution alternatives are required to create N-1 back-up capability at the substation level[7] (e.g. install a second substation transformer).
- When planning a new substation, circuits should be designed to have as many ties to other area substations as possible. Circuits that do not allow for ties to other area substations due to their geography should be designed to have ties to circuits from separate bus sections from the same substation.
- Substations will be designed to allow the installation of a mobile transformer.

[7] *For existing substations, full rebuild justification should be required to advance N-1 redundancy at the substation.*

The table below shows the substation transformer ratings and durations to be used for Normal and LTE.

Table 1: Substation Transformer Ratings and Durations[8]

Description	Normal		Long Term Emergency (LTE) CT & ME		Long Term Emergency (LTE) NY	
	Sum.	Win.	Sum.	Win.	Sum.	Win.
Pre-Load % of Top Nameplate	100%	100%	100%	100%	100%	100%
Load Duration	24 hrs	24 hrs	12 hrs[9]	4 hrs[8]	4 hrs[10]	4 hrs[9]
Transformers < 10 MVA (% of Nameplate)	100%	115%	125%	140%	125%	140%
Transformers 10 thru 99 MVA (% of Nameplate)	105%	120%	130%	145%	130%	145%

All new Bulk Energy System (BES[11]) power transformers should be rated based on Avangrid's Facility Rating Methodology (TM 2.71.60) Appendix D. New BES transformers should be rated using EPRI's PTLOAD program to determine power transformer overload/ thermal loading capabilities by the Facility Ratings Group of Avangrid.

For service transformers including pad mounted and step-down banks, Avangrid's DEG 5.0 states that "New installations of stepdown transformer banks should be loaded to 80% of their nameplate ratings, allowing for load growth. Transformers, including Step-down units, can typically be loaded over their nameplate rating by 20 percent in the summer and 40 percent in the winter."

3.2.4 N-1 CONTINGENCY DISTRIBUTION FEEDER

When analysing the N-1 loss of a single radial distribution circuit, it is assumed that the fault occurs at the first section out of the substation during peak load conditions and the entire load from the faulted circuit must be backed Appropriate ties must be available so that all the load of the faulted circuit can be transferred to either an adjacent circuit at the same substation or circuits supplied from neighbouring substations without exceeding their LTE ratings. Distribution circuits with adequate tie points and

[8] *Values do not apply to substation padmount transformers*
[9] *Based on ISO-NE Planning Procedure 7*

[10] *Based on the New York Transmission Owners Task Force on Tie-Line Ratings Final Report 2019*
[11] *BES – Bulk Energy System generally operated at voltages at or above 100kV*

sectionalizing points offer flexibility during first contingency operation. This provides the ability to restore as many customers as possible and isolate faulted line sections.

The thermal loading of the wire and cable portions of a circuit should not exceed the contingency ratings under emergency conditions. *The normal ratings of wire and cable shall be used for any first contingency condition that can be expected to last beyond one 24-hour load cycle.*

For circuits that do not have feeder telemetry, a Load Diversity Factor (LDF) of 95% should be applied when combining the faulted circuit's load and the backup circuit's loads. LDF refers to the assumption that not all loads or customers from the circuits under review will peak at the same time.

Contingency ratings for wire and cable can be found on DEG 5.2 Avangrid Distribution Overhead Conductor Wire and Cable Ratings and Avangrid DEG 10.3 Underground Cable Ratings Standards.

When the customer count per isolating device on any distribution circuit exceeds 500 the circuit will be reviewed for further sectionalizing opportunities. On circuit open wire mainlines, a minimum of one switching location (preferably gang-operated switch) every 1,500 feet should be provided.

In some locations with special needs, such as secondary networks or areas with high population density, it may be necessary to provide N-2 contingency planning.

Where practical, the normal supply and the contingency supply to a critical or major customer load should not originate from the same substation bus section. This, however, does not imply that all of a substation's bus load must be backed up for a bus outage.

3.2.5 ALLOWABLE NUMBER OF SWITCHING OPERATIONS

Distribution circuits must have load transfer capabilities to adjoining circuits within the approved service reliability criteria after fault conditions.

To limit the complexity and time to manually restore service the following maximum switching operations is required during N-1 contingency planning:

- *No more than six (6) switching steps to restore service*

If the number of switching steps listed above is exceeded or cannot be met, a distribution project or solution should be recommended to address the N-1 issue. Performing temporary switching from season to season to address overloads in an area is not acceptable and a permanent solution must be recommended.

With the deployment of more SCADA enabled switching devices, Avangrid will be able to implement automatic restoration logic to ensure the minimal amount of customers are impacted by any single event.

4. Reliability Assessment Criteria

Power reliability can be defined as the degree to which the performance of the elements in a system results in electricity being delivered to customers within accepted standards and in the amount desired. The degree of reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply.

4.1 AVANGRID RELIABILITY INDICES

The reliability goals across all Avangrid OpCos are standardized to the industry accepted reliability indices of Customer Average Interruption Duration Index (CAIDI), System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI). These indices consider sustained interruptions, which are those greater than 5 minutes in length. Shorter interruptions, known as temporary interruptions, are not included in the calculations of these indices. The period considered for these indices is one calendar year.

The CAIDI index represents the average time needed to restore service to the average customer per sustained interruption. It is the sum of customer interruption durations divided by the total number of customer interruptions as follows:

$$CAIDI = \frac{\sum Customer\ Interruption\ Hours}{\sum Customers\ Interrupted}$$

The SAIFI index represents the average frequency of sustained interruptions per customer in the system over a predefined period. It is the total number of customer interruptions divided by the total number of customers served or connected in the system as follows:

$$SAIFI = \frac{\sum Customers\ Interrupted}{\sum Total\ Number\ of\ Customers}$$

The SAIDI index represents the average duration of sustained interruptions per customer in the system over a predefined period of time. It is the total number of meter-hours interrupted divided by the total number of customers served or connected in the system as follows:

$$SAIDI = \frac{\sum Customer\ Interruption\ Hours}{\sum Total\ Number\ of\ Customers}$$

The Reliability indices listed above are tracked internally for every OpCo and reported on an annual basis to each state's regulatory commission.

In addition to the indices explained above, additional metrics may be evaluated in order to get a better understanding on the system performance, customer experience and future risks to reliability. Appendix 3 provides additional reliability metrics that may be used to further evaluate the performance of the system and the customer experience. Please note that Avangrid is currently not calculating or reporting on these other reliability metrics.

4.2 WORST PERFORMING CIRCUITS

Distribution system reliability analyses identify Avangrid's worst performing distribution circuits and assess the reliability improvements that may be gained by decreasing the number of customers affected or duration by a single outage event, providing alternative sources, implementing automation schemes, and ensuring that circuits operate within operating limits.

Per regulatory orders in each state, remedial action is required when distribution circuits are identified as a Worst Performing Circuit for the individual OpCos. In order to evaluate individual circuit performance, multiple Key Performance Indicators (KPIs) need to be considered. The main KPIs are the Sustained Interruption Indices since their use is widespread in the industry.

Consequently, it is key to calculate the contribution to system's SAIFI and CAIDI, where the individual distribution circuit's performance is weighted against the performance of the specific operating company using the following formulas:

$$\%\ Contribution\ to\ System\ SAIFI = 100 * \frac{\left(\frac{\sum Customer\ Interruptions\ on\ Circuit\ XX}{\sum Customers\ Connected\ at\ OpCo}\right)}{OpCo\ SAIFI}$$

$$\%\ Contribution\ to\ System\ CAIDI = 100 * \frac{\left(\frac{\sum Customer\ Interruption\ Hours\ on\ Circuit\ XX}{\sum Customer\ Interruption\ Hours\ at\ OpCo}\right)}{OpCo\ CAIDI}$$

A period of three (3) full calendar years (previous) should be used to perform the analysis. In order to mitigate the variability of weather events, the percent contribution to system SAIFI and CAIDI is calculated using a 3-year timeframe using the following formulas:

$$3Y\ \%\ Cont.to\ System\ SAIFI = 100 * \frac{\sum Customer\ Interruptions\ on\ Circuit\ XX\ 3y}{\sum Customer\ Interruptions\ on\ OpCo\ XX\ 3y}$$

$$3Y\ \%\ Cont.to\ System\ CAIDI = 100 * \frac{\sum Customer\ Interruptions\ Hours\ on\ Circuit\ XX\ 3y}{\sum Customer\ Interruptions\ Hours\ on\ OpCo\ XX\ 3y}$$

The circuits are then ranked using these weighted values, which must be interpreted based on the underlying events the circuit experienced. These two lists are then used to select the worst performing circuits of specific operating areas for the annual reliability reports. *The circuits contributing to 30% of the OPCO reliability performance are identified for specific review and potential reliability improvement initiatives.*

Finally, in Connecticut, the Public Utility Regulatory Authority (PURA) has established additional customer focused reliability indices which must be tracked and reported on a yearly basis as well as more detailed recommendations on worst performing circuits assessment, which can be found in Appendix 3 (Applicable to UI only).

5. Distribution Automation

Deploying Distribution Automation (DA) assets is a key tool for utilities to have better operability of the system and to improve reliability performance. By leveraging DA, utilities can minimize the impact of outage events while decreasing the time required to restore service to customers. DA deployments provide the ability to sectionalize and restore unaffected portions of the feeder before an outage can be considered sustained, therefore, converting many more sustained outages into momentary outages. DA deployment limits the number of customers affected by main line faults, and DA control allows operators to restore service remotely more rapidly than waiting for field response. The Electric Power Research Institute (EPRI) defines DA as "A system of medium voltage switches, communications and control software, that enables remote monitoring, sensing and automatic control of devices on the distribution system".

Avangrid uses a general rule of thumb to install remote control devices to make customers pockets or zones of 300 to 500 customers and/or 10 miles; also end of mainline fault current should be no less than twice the peak load current of the circuit, however, this is to be analyzed on a case by case basis.

Mainline reclosers will be set with pickups between 100A and 300A, in coordination with the largest fuse size within the respective zone of protection. Tie reclosers settings will be studied on a case-by-case basis.

Fuse coordination should follow the established fusing guidelines from Avangrid's Distribution Network Standards Group.

Reclosers and SCADA Switches are utilized as part of Avangrid's DA Program. Reclosers are used to isolate mainline branches and at tie points[12] to facilitate remote restoration. As a general rule, no more than three reclosers should be installed in series due to coordination issues, except for sequential reclosing operation. SCADA Switches are installed along a circuit to minimize and isolate the number of customers in individual sections or pockets.

Avangrid employs the following schemes as part of its DA program:

- Advanced Restoration Automation (ARA)
- Loop Scheme
- Sequential Reclosing

The following sections provide additional details on each of these schemes.

5.1 ADVANCED RESTORATION AUTOMATION (ARA)

Advanced Restoration Automation (ARA) schemes leverage a utility's deployed DA assets and communications structure to enable automated restoration, further reducing the scale and duration of outage events. Avangrid can implement this system as an additional feature to the existing SCADA system. ARA will aid operators in detecting and isolating distribution faults while restoring unfaulted line sections automatically using SCADA control. This system can operate in closed or open loop, either performing the necessary switching to restore customers automatically or by generating a list of recommended steps for operators to execute and restore service.

ARA utilizes SCADA enabled devices such as reclosers, SCADA Switches, and circuit breakers to identify the optimal way of restoring as much service as possible within three minutes of the outage occurrence. Avangrid will receive an ancillary benefit by avoiding the need to dispatch Field Services in order to operate the proposed switching schedule.

5.2 LOOP SCHEME

Loop Scheme is a simple scheme involving a few reclosers using time duration and voltage level to isolate faulted sections of the grid and restore un-faulted sections of the grid based on predetermined logic. Loop schemes use standard recloser features to reconfigure protection settings, sectionalize faults, minimize affected areas, and restore network supply without the need for communications or operator intervention.

Loop schemes automatically reconfigure a feeder affected by an outage when an alternative source of supply is available. The alternative source is typically a second feeder connected via a normally open point.

[12] *Reclosers at tie points with settings currently only being applied in NY, CMP uses reclosers at tie points with no settings*

5.3 SEQUENTIAL RECLOSING SCHEME

Avangrid will utilize Sequential Reclosing Schemes where applicable, allowing for more reclosers to be installed in series than traditional recloser placement practices. Sequential reclosing helps further segment circuits creating smaller pockets or zones of customers between sectionalizing devices. Smaller pockets of customers, along with increased sectionalizing of circuits will help Avangrid manage outages by minimizing the scale/impact of the event. Sequential Reclosing Schemes are compatible with the use of ARA and Loop Schemes.

6. Power Flow Software

The Avangrid OpCos use CYME (by Eaton) as the distribution power flow software tool to perform engineering analysis. The CYME Power System Analysis software ("CYMDIST") is a Power Engineering analysis tool used to simulate the distribution system and to assess its performance for planning, operational, and contingency purposes. Furthermore, CYMDIST is used to perform Reliability Assessment, Network Optimization, Coordination of Protection Devices, as well as to analyze and assess the impact of interconnection of new DER on the distribution system, commonly referred to as Distributed Generation (DG). The tool is also used to develop DER hosting capacity analyses and maps for PV, Battery Storage and EVs. These analyses enable the Engineering Departments to develop safe, economic and reliable system solutions.

The figure below shows the components and sources of data required to create CYME models and perform the different types of analyses

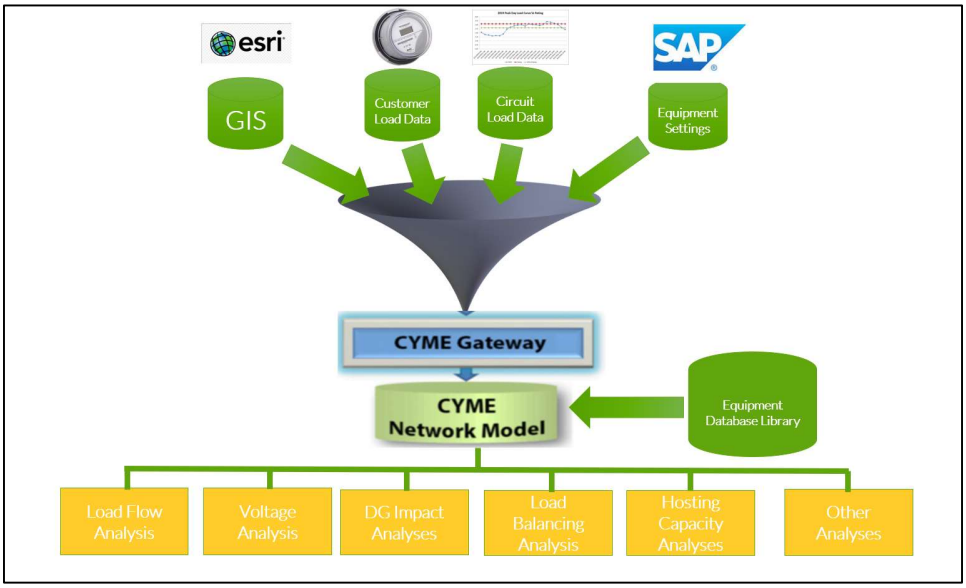


Figure 2: CYME Modelling Process

As can be seen from the figure above, the CYME Gateway connects to the Avangrid source systems to obtain the electrical connectivity from GIS, Customer load (demand or usage where available), circuit load data (where available) and equipment settings. The CYME gateway also connects to the CYME Equipment database which contains the equipment characteristic information such as impedance and ratings. The base models are then created in one database containing the electrical connectivity and the impedance and

ratings information combined. Once the models are validated and verified, engineers can start performing different power flow analyses.

6.1 STUDY ASSUMPTIONS

6.1.1 PEAK LOAD RECONSTITUTION

The largest in-service or approved[13] generator (greater than 1 MW) or the generator with the largest output at the time of peak connected to a substation and circuit is assumed to be off-line. When available, the actual output of the generator should be included as an adder in the total peak load of the substation and circuit to reconstitute the peak value.

The reconstitution of large DG output at this level is required due to load masking since the company must be prepared to provide capacity in the event a large customer owned DG is unavailable at peak. The company does not have control over the operation of these large DG units.

When actual generator output is unknown, an assumed output factor should be used based on generator technology and the substation and circuit peak time season. The values in the table below are general output assumptions for Solar PV, Battery Storage and other DG technologies, when available, it is recommended to use actual generator output data.

Table 2: DG Coincident Capacity Factors

DG Source	Summer Capacity Factor	Winter Capacity Factor
Solar PV	26%	0%
Battery Storage	Nameplate MWh / 6	Nameplate MWh / 6
Fuel Cells, Synchronous, Turbine, Others	100% of Nameplate	100% of Nameplate

6.1.2 VOLTAGE DROP CALCULATIONS

When performing voltage drop calculations or analysis for residential and commercial customers' service voltage, the maximum primary voltage drop from the substation to the last customer is 10% at peak load, assuming voltage

[13] *Approved Generators are those that have a signed interconnection agreement with the OpCo.*

regulation at the substation (126V – 114V on a 120V base). A threshold of 117V on the primary side should be used while performing power flow analyses to flag a potential low voltage condition with 3V drop reserved for the distribution transformer, secondary wire and customer service cable. When performing voltage drop or load flow analyses, starting source voltages (from transmission system) of 0.95 PU, 1.0 PU and 1.05 PU should be evaluated.

Distribution Planning analyze voltage levels on the primary side of the system using power flow software during normal conditions (N-0) for Range A at the following 117V – 126V and during contingency conditions (N-1) for Range B at the following 113V – 127V.

7. Interconnections (Load & DER)

Distribution Planning will analyze the impacts of any significant interconnection to the distribution network to ensure no interruption of service to existing customers occurs.

7.1 LOAD INTERCONNECTION

Distribution Planning will be notified for technical recommendations when new or existing customer requests to connect a three-phase diversified load of 500 kVA or more to the distribution system are made. Any new or existing customer load request over 500 kVA and less than 1 MVA will receive an informal report and loads over 1 MVA will receive a formal detailed report. For new loads over 1MVA, Distribution Planning will also notify Transmission Planning to determine the impact to the transmission system. It is also required that Distribution Engineering (Operations) provides Distribution Planning all queued/pending new load requests on the impacted circuit and substation transformer bank. All new customer loads below 500 kVA shall be evaluated by Distribution Engineering working with Distribution Planning as needed.

New motor loads between less than 500 kVA shall be sent to Distribution Engineering to evaluate the impact of motor startups for flicker and voltage drop. Any new motor load larger than 500 kVA shall be sent to Distribution Planning for a load study and technical recommendations.

The table below provides a summary of the roles and responsibilities by department for new load interconnection requests.

Table3: New Load Interconnections Roles & Responsibilities

Peak Demand of Load Interconnection / Power of Motor	Distribution Planning		Distribution Engineering		Transmission Planning	
	Notify	Evaluate	Notify	Evaluate	Notify	Evaluate
Loads < 500kVA	x			x		
500kVA < Loads < 1 MVA		x	x		x[14]	
1 MVA < Loads < 10 MVA (12kV) or 18 MVA (34kV)		x	x			x
Loads > 10 MVA (12kV) or 18 MVA (34kV)	x		x			x
Motors < 500 kVA				x		

Appendix 4 provides diversification factors to be used to estimate peak demand based on different types of connected loads provided.

New load requests greater than 6.5MW (12kV) or >10MW (35kV) shall be considered for express feed to ensure customer load requirements are met and to reduce the risk of extended outages for other customers. New load requests greater than 10MW (12kV) or 18MW (35kV) may also result in the inability to support this amount of capacity on an existing distribution circuit and will need to go to Transmission Planning and Project Development for a detailed study on system recommendations before involving Distribution Planning.

Under normal loading conditions, the addition of the new load shall not violate any of the criteria outlined in the Distribution Planning Criteria. When addition of new loads results in the violation of criteria, Distribution Planning will evaluate alternatives to accommodate the proposed load.

New customer loads should not worsen or create new normal or N-1 contingency conditions. Circuits with automated schemes will require review to ensure the new load does not impact the control schema.

Existing customers with independent redundant feeds shall have the peak load evaluated on all feeds. Appropriate capacity for these customers will be reserved on the backup emergency feeds.

7.2 GENERATION INTERCONNECTION

[14] *As needed based on specific capacity deficient Transmission areas*

Distribution Planning will be notified for technical analysis when a new or existing customer requests to connect a generator greater than 300 kW for NYSEG and RG&E and 100 kW for UI or an application that triggers an impact study (as a Level 4 application for CMP) according to each state's interconnection rules and requirements. Each state or OpCo DG Interconnection document provides additional guidance on the interconnection requirements. See Appendix 2 for links to each state's Generator Interconnection Requirement documents.

The addition of the new generation shall not violate any of the criteria outlined in the Distribution Planning Criteria under normal and/or contingency conditions, or any requirements outlined in any regulatory generation interconnection document. When the addition of new generation results in a violation of these guidelines, Distribution Planning will recommend system reinforcements to address the violations.

If the generator is transferred to an alternate feeder, Avangrid reserves the right to disconnect the generator from the distribution system if the generator negatively impacts the power quality performance of the system or other customers.

New or existing generators shall be interconnected with accordance with the requirements specified in the newest version of IEEE 1547 Standard.

Please note that as of January 1, 2023, the New York Joint Utilities implemented a requirement for all inverter-based resources to use IEEE Standard 1547-2018 compliant and UL 1741 SB certified (smart) inverters.

8. Load Forecasting

Company level peak load forecasts are generated at each OpCo's system level by a methodology that utilizes a single multi-variable econometric model that includes both weather and economic variables to estimate the concurrent impact of each of these drivers on Peak MW. Additionally, DER output at the time of the system peak is also accounted for in the econometric model. The estimated coefficients are then used in simulation runs to model Normal Scenario (50-50) and Extreme Scenario (90-10) weather conditions. This methodology yields normalized historical peaks as well as forecasted peaks under both weather scenarios. The normal peak load is based on average historical weather data, and the extreme peak is based on the 90th percentile of that historical weather data. The extreme peak is referred to as a 90-10 forecast because it assumes a 10% chance that the forecasted peak load would be exceeded. Put another way, the forecast will be exceeded on average only once every 10 years. The 90-10 (extreme weather scenario) for summer or winter shall be used for planning load forecast purposes.

The corporate-level peak forecast is then disaggregated across Divisions or Service Centers and/or Substations based on localized growth trends from a granular analysis of local economic development data. In addition to the econometric (background) load growth calculated as a Compounded Annual Growth Rate (CAGR) from the load forecast, the load projections at the circuit and substation level should also consider specific customer new spot loads as well electrification of transportation and heat.

9. Non-Wires Alternatives (NWA) / Non-Wires Solutions (NWS)

Non-Wires Alternatives (NWA) and Non-Wires Solutions (NWS) projects are non-traditional solutions that can mitigate a system need and may defer, delay, or avoid traditional distribution grid infrastructure

investments. These solutions usually include DER such as distributed generation (DG), energy storage (ES), energy efficiency (EE), demand response (DR), and grid software and controls.

Currently, New York and Maine have active NWA programs while the NWS program is under development in Connecticut as described below in Section 9.1.3 Connecticut. Avangrid's strategy is to pursue NWA projects which are cost effective for customers, provide reliable alternatives to traditional capital investment projects, and comply with regulatory and/or legislative directives and environmental policies.

NWA solutions are an important consideration in the distribution planning process. New constraints should be evaluated for NWA suitability, including those driven by resource location, time-based performance, economic considerations, and design. The following sections summarize each state's established requirements and criteria for NWA applicability.

9.1 STATE/TECHNICAL REQUIREMENTS

Avangrid's NWA framework varies within each of the states that the Company operates due to varying regulatory and/or legislative requirements.

9.1.1 NEW YORK

In New York, the NWA framework was originally established for evaluation of traditional electric distribution projects through the state's Reforming the Energy Vision (REV) proceeding and has since been expanded through the Distributed System Implementation Plan (DSIP) which enhanced the existing process to include traditional electric transmission projects. The NWA process is a critical pathway to support achievement of the goals established by the Climate Leadership and Community Protection Act (CLCPA) in New York.

The NWA process in New York consists of applying a set of suitability criteria to all transmission and distribution projects. The OpCos use the suitability criteria to determine which traditional wires solutions may be deferred or avoided via an NWA solution based on project type, timeline, and project cost. The NWA suitability criteria is shown within the table below.

Suitability Criteria	Potential Elements Addressed
Project Type Suitability	• Load Relief projects that do not involve a customer contribution or have a specific customer in-service date that is sooner than the timeline suitability criteria of 36 months. • Reliability projects and/or a combination of reliability and load relief projects.
Timeline Suitability	• Minimum of 36 months to time of need.
Cost Suitability	• Projects with construction cost greater than $1M.

Figure 3: NY NWA Suitability Criteria

On an annual basis, the OpCos apply the NWA suitability criteria to the full list of electric transmission and distribution projects included in the OpCos five-year Capital Investment Plan. This process enables proactive and comprehensive review and identification of NWA opportunities. Additionally, the OpCos have established various checkpoints in the project approval process to ensure NWA solutions are fully

contemplated as alternatives to defer or avoid the traditional capital project. The New York Non-Wires Alternatives Opportunity Identification and Scoping Process Guide document provides a detailed overview of how NWA solutions are identified and evaluated as part of the distribution system planning process.

9.1.2 MAINE

In Maine, the Company's NWA framework was originally established through LD 1181: An Act To Reduce Electricity Costs through Nonwires Alternatives and, subsequently updated through LD 1887: An Act To Clarify the Review and Procurement Process For Nonwires Alternatives. The NWA Statute in Maine (the "Statute") establishes a third-party NWA Coordinator through the Office of Public Advocate. The NWA Coordinator will make recommendations to utility transmission and distribution (T&D) planning studies, investigate utility projects for NWA solutions and recommend NWA projects to the Commission. Based on the Statute,

- Any project $500,000 or higher is required to be evaluated for an NWA unless the project meets established exclusion criteria under the Chapter 319 MPUC order;
- Utilities are required to annually file a five-year T&D planning study for small transmission (>69 kV, <$5M) and all distribution projects;
- Efficiency Maine Trust is established as the implementer of behind the meter NWA solutions;
- The threshold for Commission approval requirements on transmission projects is lowered to projects over $5,000,000;

The Statue also states that prudently incurred costs of NWA solutions can be recovered by the utility through rates.

9.1.3 CONNECTICUT

The Non-Wires Solutions (NWS) framework in Connecticut is currently being developed through Docket Nos. 17-12-03 RE07 PURA Investigation Into Distribution System Planning of the Electric Distribution Companies – Non-Wires Alternatives and 24-08-08 Non-Wires Solutions Process Initiation Phase and goes into effect January 1, 2025. A third-party consultant or Process Monitor to PURA has been hired to help establish the NWS program's framework. The Process Monitor's role is to facilitate stakeholder meetings, review the annual data filing, provide oversight over the NWS procurement process, and report to PURA any comments about the overall NWS program.

UI along with Eversource are currently working with the Process Monitor to establish the NWS program including the annual filing and its requirements, procurement process, cyber security processes, etc. The NWS program is expected to be fully established by the end of 2024.

10. Investment Planning

Avangrid uses a rigorous technical and financial approval process for Capital investments with checks and balances at each phase of the process. Distribution system improvements are identified as a result of many different types of system needs or drivers, criteria violations, or risks that can jeopardize the service reliability to customers. System needs are analyzed for proper justification during the Origination Phase

(IP1) of the process. Once the Need is verified, Solution Alternatives are developed (including NWAs when applicable) during the Technical Phase (IP2) to address the violation based on safety, reliability and cost effectiveness. Once Technical approval is obtained, the project moves on to Financial approval (IP3) and finally it is designed and constructed. The figure below shows overall Investment Planning process.

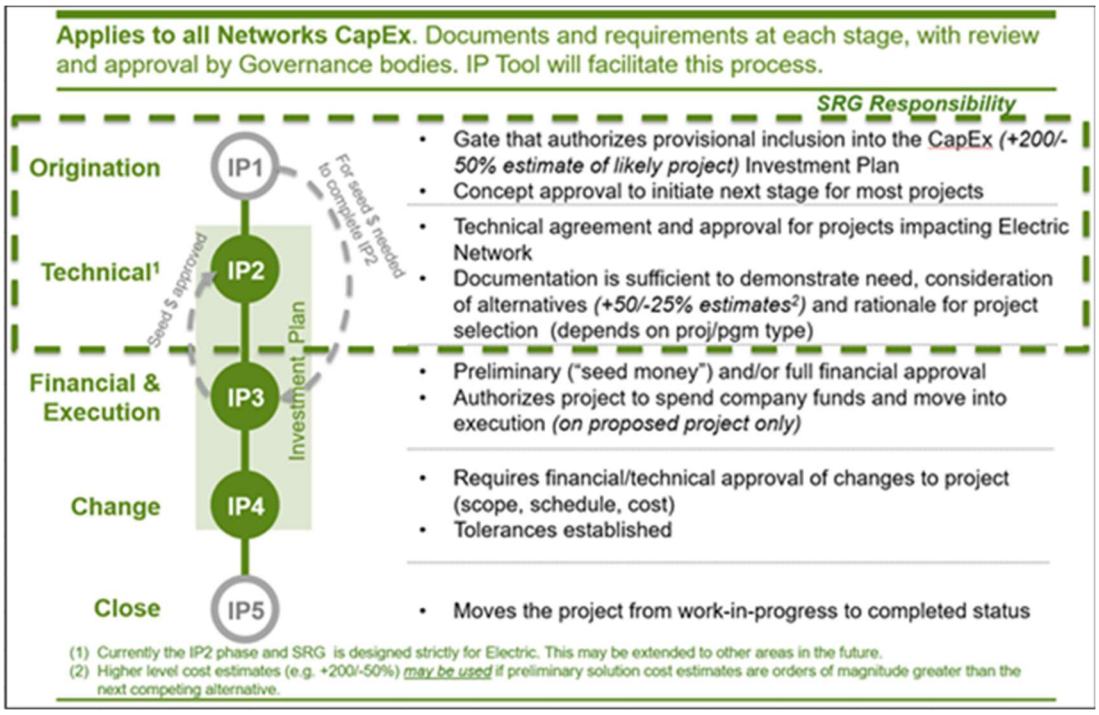


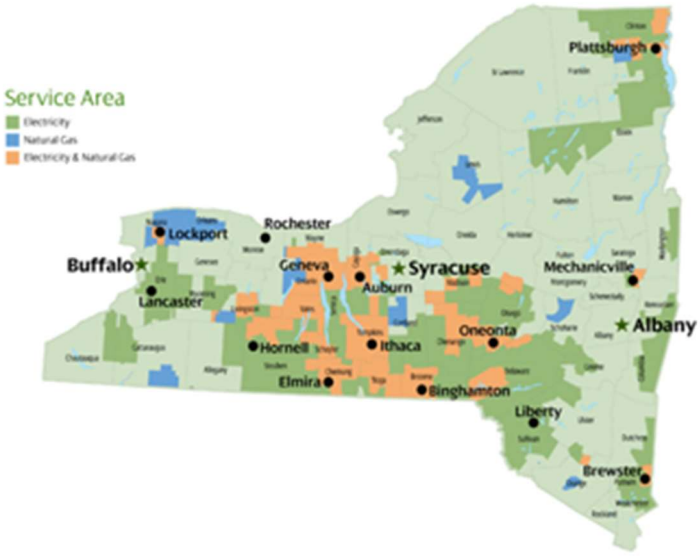
Figure 4: Investment Planning Process

As a part of the technical phase (IP2), Planners and other engineers are required to evaluate the impact of their proposed investments on system reliability. Reliability improvement is one of the factors taken into account in the Company's capital investment prioritization form which must also be completed prior to IP2 approval.

Appendix 1: Avangrid Operating Companies Characteristics

NEW YORK STATE ELECTRIC & GAS (NYSEG)

- All-time system peak load of 3,365 MW on July 21, 2011
- Approximately 900,000 electric customers
- Approximately 18,000 square miles of service area
- Serves approximately 40% of Upstate New York
- Approximately 430 distribution substations
- Approximately substation 960 transformer banks
- Approximately 1,390 distribution circuits
- Approximately 35,000 miles of distribution lines
    - Approximately 3,000 miles of underground primary cables
    - Approximately 29,000 miles of overhead conductors
- Two underground secondary network systems (Binghamton & Auburn)



ROCHESTER GAS & ELECTRIC (RG&E)

- All-time system peak load of 1,765 MW on July 21, 2011
- Approximately 385,000 electric customers
- Approximately 2,700 square miles of service area
- Serves areas surrounding City of Rochester
- Approximately 156 distribution substations
- Approximately substation 280 transformer banks
- Approximately 620 distribution circuits
- Approximately 8,000 miles of distribution lines
    - Approximately 3,000 miles of underground primary cables
    - Approximately 5,000 miles of overhead conductors
- One underground secondary network system (Downtown Rochester)



CENTRAL MAINE POWER (CMP)



- All-time system peak load of 1,809 MW in 2021
- Approximately 630,000 electric customers
- Approximately 11,000 square miles of service area
- Serves 11 Divisions
- Approximately 200 distribution substations
- Approximately 250 substation transformer banks
- Approximately 470 distribution circuits
- Approximately 26,000 miles of distribution lines
  - Approximately 2,000 miles of underground primary cables
  - Approximately 24,000 miles of overhead conductors
- One underground secondary network system (Downtown Portland)

THE UNITED ILLUMINATING COMPANY (UI)



- All-time system peak load of 1,456 MW on August 3, 2006
- Approximately 340,000 electric customers
- Approximately 335 square miles of service area
- Serves 17 towns/cities in Southwest Connecticut including major cities of Bridgeport and New Haven
- 28 distribution substations (13.8 kV)
- 57 substation transformer banks
- Approximately 340 distribution circuits
- Approximately 3,200 miles of distribution lines
  - Approximately 700 miles of underground primary cables
  - Approximately 2,500 miles of overhead conductors
- Two underground secondary network systems (Downtown Bridgeport and Downtown New Haven)

Appendix 2: Useful Links

1. Document Repository for Integrated System Planning - ISP OneDrive
2. Integrated System Planning Web Tool - ISP Web Tool
3. Avangrid Distribution Standards - Avangrid Standards
4. Investment Planning Tool - Clarity PPM
5. Distribution System Review Group Teams Page - D-SRG
6. Transmission System Review Group Teams Page - T-SRG
7. Guideline for Substation Configuration - TM 2.00.01
8. Maine NWA Exclusion Criteria - MPUC Chapter 319
9. Individual State Generator Interconnection Requirement Documents

New York Generator Interconnection Requirements:

Bulletin 86-01 Requirements for the Interconnection of Generation, Transmission and End-User Facilities (see Attachment 2: NY Bulleting 86-01 Distributed Generation Technical Review Process)

New York State Standardized Interconnection Requirement and Application Process for New Distributed Generators and Energy Storage Systems 5 MW or Less Connected in Parallel with Utility Distribution Systems.

Maine Interconnection Requirements:

Chapter 324 Small Generator Interconnection Procedures

CMP Schedule B - Transmission & Distribution Interconnection Requirements for Generation

Connecticut Interconnection Requirements:

Guidelines for Generator Interconnection, Fast Track and Study Process

Exhibit B - Generator Interconnection Technical Requirements

Appendix 3: Additional Reliability Metrics

The following reliability metrics apply to UI only and have been included in this document with the purpose of characterizing the utility performance from the perspective of the customer rather than the perspective of the system.

CEMI-n stands for 'Customers Experiencing Multiple Interruptions' and represents a measurement of repeated outages suffered by customers. This metric captures the percentage of customers experiencing more than a defined number of sustained interruptions 'n' in a year.

CELID-n stands for 'Customers Experiencing Long Interruption Durations' and displays the percentage of customers experiencing long (i.e., more than 'n' hours) interruptions over the course of a year.

CEMSMI-n stands for 'Customers Experiencing Multiple Sustained Interruptions and Momentary Interruption Events'. It tracks the number 'n' of both sustained interruptions and momentary interruption events.

CEMM-n stands for 'Customers Experiencing Multiple Momentary Outages' and tracks the number of customers experiencing momentary interruptions. It shows the percentage of customers experiencing more than a defined number of sustained interruptions 'n' in a year.

CEMI, CELID, CEMSMI, and CEMM are reported for customers experiencing three or more, five or more, seven or more, and nine or more sustained interruptions, in accordance with the following categories:

- Including Major Storms
- Excluding Major Storms
- Including planned outages & Major Storms
- Excluding planned outages & Major Storms

Utilities may individually evaluate the situation of those customers experiencing more than 'n' = 3, 5, 7 and 9 outages / hours per year. This applies to every customer-centric indicator and every category.

Finally, PURA has also established recommendations for the 'Worst Performing Circuits Program'. It suggests analysing the most recent four calendar years of reliability data and implement a holistic approach that evaluates the KPIs above in addition to SAIFI and SAIDI.

Appendix 4: Load Diversification Factors

Peak demand estimation

When necessary, the summer and winter peak kVA/kW demands will be estimated by applying the following diversification factors to the provided connected loads:

Note: These diversification factors are being provided as a general guide only and should be adjusted by the Planner if necessary, given the specific characteristics of the load being estimated.

- A peak building/dwelling/unit diversified kVA will be calculated by applying the following diversity factors:
  - 100% Lighting
  - 75% Air conditioning (summer peak only)
  - 75% Heating (winter peak only)
  - 75% Computer
  - 40% Cooking
  - 100% Continuous Operations Motor Load
  - 50% Semi-Continuous Motor Load
  - 30% General Purpose Motor Load
  - 10% Receptacles
  - 50% Refrigeration
  - 60% Water heating
  - 30% Special Equipment (elevators, welders, X-ray, etc.)
  - 50% Miscellaneous
  - 80% Future Loads
  - 100% Electric Vehicle Charging Station

- For multiple building/dwelling/unit calculations, the following diversification factors can be applied:

  - 2 - 4 units = 100%
  - 5 - 9 units = 78%
  - 10-14 units = 63%
  - 15-19 units = 53%
  - 20-24 units = 49%
  - 25-29 units = 46%
  - 30-34 units = 44%
  - 35-39 units = 42%

- 40-49 units = 41%
- 50 and more = 40%

- For diversifying new loads into the local distribution system, a factor of simultaneity will be used to account for the expected percentage of new load that will add to the existing peak of the distribution system. A standard simultaneity factor of 80% will be used if no other specific information exists for a more precise estimation. The planner will have the discretion to adjust this percentage based on their knowledge of current system peaks and expected new load demands.