Modeling Guideline for NYISO Interconnection Data

A Guideline for Prospective Cluster Study Interconnection Customers

New York Independent System Operator

Page 1 of 52

Version 10

July 1, 2024

Table of Contents

1. Purpose 5
1.1 Version History: 5
2. Scope 5
3. Definitions 6
4. Necessary Data 8
4.1 Resources Available to Interconnection Customers 9
5. Steady State Modeling Requirements 10
5.1 General Considerations 11
5.2 Bus Data 12
Grouping Data: 12
Basic Data: 12
5.3 Generator Data 13
Owner Data: 13
Wind Data: 13
Plant Data: 13
Machine Data: 13
Basic Data: 14
Transformer Data: 15
5.4 Transformer Data 16
Owner Data: 16
I/O Data: 16
Transformer Impedance Data: 16
Transformer Normal Ratings Data: 16
Control Data: 17
5.5 Auxiliary Load Data 18
Basic Data: 18
Grouping Data: 18
Load Data: 18
5.6 Shunt Data 19
Basic Data: 19

Switched Shunt Data: 19

5.7 Line Data 20

Owner Data: 20

Branch Data: 20

5.8 STATCOM Data 21

Basic Data 21

Control Data 21

Owner Data 21

Shunt Data 21

Series Data 21

5.9 SVC Data 22

Owner Data: 22

Wind Data: 22

Plant Data: 22

Machine Data: 22

Basic Data: 22

Transformer Data: 23

5.10 LCC HVDC Data 24

Line Data 24

Rectifier/Inverter Data: 24

5.11 VSC HVDC Data 26

Line Data 26

Converter Data 26

5.12 Special Considerations for Multi-Unit Facilities 28

6. Short Circuit Modeling Requirements 29

a. General Considerations for Short Circuit 29

b. Conventional Generator Data (for Synchronous Resources) 30

Internal V Source 30

Current Limits (A) 30

Power Flow Regulation 30

Generating Unit Info 30

c. VCCS Data (for Inverter Based Resources) 31

Main Data Table 31

d. Bus Data 32
e. Transformer Data 33
Two Winding Transformers 33
Three Winding Transformers 34
f. Line Data 35
g. FACTS Devices 36
STATCOMS: 36
Main Data Table 36
h. Special Considerations for HVDC Projects 37
7. Stability Modeling Requirements 38
a. General Considerations 38
b. Typical Model Structure (Inverter-Based) 39
c. Typical Model Structure (Synchronous) 40
8. Model Usability Testing 42
8.1 Procedures and Criteria for Dynamic Models 42
8.1.1 Case Setup 42
8.1.2 Procedures and Criteria for the 20-second flat run test. 42
8.1.3 Procedures and Criteria for the 9-cycle 3-phase fault test: 43
8.1.4 NERC PRC-024 Protection Settings Criteria 44
8.1.4.1: PRC-024 Voltage Requirements 44
8.1.4.2: PRC-024 Frequency Requirements 45
8.1.5 TO Specific Criteria for Fault Ride-Through Performance and Protection 47
8.1.5.1: LIPA Dynamic Requirements 47
8.1.5.2: LIPA Protection Requirements 47
8.1.6 Criteria for Primary Frequency Response, Droop, and Deadband 49
8.2 Procedures and Criteria for Short Circuit Models 50
8.2.1 Criteria for fault response 50
8.2.2 Criteria for VCCS Parameters (IBR only) 50
9. References 52

1. Purpose

This guideline was developed to document the NYISO's standards and requirements as they relate to interconnection project models required for projects entering a Cluster Study, including the Transitional Cluster Study, pursuant to Attachment HH of the NYISO OATT.

1.1 Version History:

Version	Changes
1.0	Initial Document

2. Scope

The guideline outlines the following data requirements:

- One-line diagrams
- Steady State Data
- Short Circuit Data
- Stability Data
- Model Usability Testing

3. Definitions

CBA case: The Cluster Baseline Assessment case for a Cluster Study that does not include the projects in that Cluster Study (*i.e.*, the “pre-project case”).

.CHF: A Change file, which records a series of ASPEN Oneliner™ commands. In the context of this document, the .CFH will add the model of a project to an existing ASPEN Oneliner™ case.

CPA case: The Cluster Project Assessment case for a Cluster Study that does include the projects in that Cluster Study.

CSR: Co-Located Storage Resources, a market structure that allows an Energy Storage Resource and a wind or solar intermittent power resource to be located behind the same POI as one Generator.

HSR: Hybrid Storage Resource, a market structure that allows one Energy Storage Resource (“ESR”) and at least one Intermittent Power Resource (IPR) and/or Run-of-River (RoR) Hydro resource located behind the same POI to be treated as one Generator.

CTO: Connecting Transmission Owner

.DLL: A Dynamic Link Library file. In the context of this document, these contain a user-written stability model for a project.

.DYR: A PSSE Dynamics File, which contains data for dynamic generator, controller, and protection models.

ERIS: Energy Resource Interconnection Service – the service provided by the NYISO to interconnect the Interconnection Customer’s Generating Facility or Cluster Study Transmission Project to the New York State Transmission System or to the Distribution System, in accordance with the NYISO Minimum Interconnection Standard, to enable the New York State Transmission System to receive Energy and Ancillary Services from the Generating Facility or Cluster Study Transmission Project, pursuant to the terms of the ISO OATT.

FACTS: Flexible Alternating Current Transmission Systems

FERC: Federal Energy Regulatory Commission

GSU: Generator Step Up Transformer. Here defined as the step up transformer from the generator unit voltage to the collector system voltage.

HVDC: High voltage direct current

.IDV: An “Idev” file, which records a series of PSSE commands for later playback. In the context of this document, the .IDV will add the model of a project to an existing PSSE case.

LCC: Line-Commutated Converter, a type of HVDC technology.

NERC: Northern Electric Reliability Corporation: The organization that sets technical standards and enforces compliance for the North American power grid (US and Canada).

NPCC: Northeastern Power Coordinating Council: A Regional Entity that sets further standards for the interconnection of NYISO, ISO-New England, Ontario, Hydro Quebec, and Nova Scotia.

NYISO OATT: NYISO's Open Access Transmission Tariff

.OLR: An ASPEN Oneliner™ file, which holds short circuit data in a format specific to ASPEN Oneliner™.

Pgen: Power Generated, or the current output of a unit in MW.

Pmax: Maximum power, or the nameplate rating of a unit in MW.

POI: Point of Interconnection.

Project: The proposed facility as described in a single Interconnection Request submitted under the NYISO's Standard Interconnection Procedures in Attachment HH of the NYISO OATT.

PSSE: **PSS®E** Power System Simulator for Engineering, a positive sequence, rms, fundamental frequency simulation software package published by Siemens.

PSU: Plant Step Up transformer, or the main transformer(s) that step up the Project to the POI voltage.

.RAW: A "Raw" file, which holds steady-state data in a universal format.

.SAV: A "Save" file, which holds steady-state data in a format specific to PSSE

.SLD: A "Slider Diagram" file, which provides a graphical representation of certain busses in a PSSE case.

SUM : Summer Peak Case

SVC: Static VAR Compensator, a FACTS device that provides dynamic reactive power for a single reactive element, with capability to switch in discrete blocks.

VCCS: Voltage Controlled Current Source

VSC: Voltage Source Converter, a type of HVDC technology

4. Necessary Data

For a complete modeling data package, the Interconnection Customer must provide the following items with its Interconnection Request:

1. A One-Line Diagram of the Project.
    a. The one-line diagram must be a professional engineering drawing.
    b. The one-line diagram must clearly label the project POI with station or line names.
    c. The one=line diagram must represent the general electrical components of the Project.
2. A Steady State Model for the Project, compatible with PSSE version 35.3.3. This includes the following components:
    a. A .sav or .raw file with the Project represented.
    The Project may be connected to a single-machine infinite bus system in this file.
    b. A .idv file in batch format that adds the Project to an existing case.
    c. A .sld file that shows the Project's busses and POI.
3. A Short-Circuit Model for the Project, compatible with ASPEN version 15.7. This includes the following components:
    a. A .olr file with the Project represented.
    b. A .chf file that adds the Project to an existing case.
4. A dynamic model for the Project, compatible with PSSE version 35.5.3. This includes the following components:
    a. A .dyr file with Project dynamic behavior and protection settings represented.
    b. Projects will be modeled using PSSE standard library models.
    c. In the case that no standard library model is available, a documented exception can be made with the following:
        i. Written documentation demonstrating that the particular project cannot be represented by a standard library model.
        ii. A user written model consisting of a .dyr file, a .dll file, other supporting files such as a umf/userpar file as applicable, and the uncompiled source code as available. This model must be of a model series already accepted by the MMWG.

4.1 Resources Available to Interconnection Customers

The following are available to assist the Interconnection Customer in the preparation and testing of an acceptable Project model:

1. NYISO Base Cases. The latest available CBA and CPA cases will be available upon request. This includes steady-state, short circuit, and stability cases.
    a. For the transitional cluster, if a CBA case is not available, Interconnection Customers may request the Class Year 2023 ATRA case, and the latest FERC-715 filing case.
    b. To request these cases, a CEII NDA must be executed: CEII Request Form
2. The NYISO Load and Capacity Data Report ("Gold Book"): 2024 NYISO Goldbook
3. NYISO Reliability Analysis Data ("RAD") Manual: NYISO RAD Manual
4. Modeling Guideline for NYISO Interconnection Data (This Document)

5. Steady State Modeling Requirements

This section details the requirements for steady state (PSSE) models submitted to the NYISO in the cluster study process.

A steady state model consists of the following:

- A .sav or .raw file with the Project modeled. This must be compatible with PSSE version 35.3.3.
- A .idv file in batch format that adds the Project to an existing case. This must be compatible with PSSE version 35.3.3.
- A .sld file that shows all Project busses and equipment. This must be compatible with PSSE version 35.3.3.

The remainder of this section details the requirements for each element within a steady state model.

5.1 General Considerations

The steady state model should be aggregated wherever possible to use the fewest number of equivalent busses and generators.

Each resource type within the Project should ideally be represented by a single equivalent generator. For example, if a Project consists of solar and energy storage, the model should have one equivalent generator representing solar resources, and one equivalent generator representing the Energy Storage resources. Where this is not possible, model one equivalent generator per resource per PSU.

The Generating Facility must meet the power factor requirements outlined in 9.5.1.1 of Appendix 15 to Attachment HH of the NYISO OATT.

5.2 Bus Data

This subsection sets out the requirements for modeling a Project bus.

Grouping Data:

The NYISO will fill out Grouping Data for each bus. By default, please leave the Area, Owner and Zone of Each bus as ‘1’

Area: 1

Owner: 1

Zone: 1

Basic Data:

Voltage and angle shall be left at the default 1 p.u. voltage, and 0 degree angle. The Project model shall use bus numbers 888000 through 888999 as needed. The NYISO will replace these when adding the Project to the CPA case. Bus names should follow the convention laid out below:

Voltage Angle: 0

Voltage Magnitude: 1.0

Bus Number: 888000-888999

Bus Names: Follow the convention in the below table, the NYISO will fill in the “####” after assigning a cluster number to the Project.

Table 5.2.1: NYISO Steady State Bus Naming Convention

Bus Type	Naming Convention
POI	C####_POI
PSU high side	C####_PSU1, C####_PSU2, etc.
Collector Station	C####_COL1, C####_COL2, etc.
GSU high side	C####_GSU1, C####_GSU2, etc.
Generator	C####_G1, C####_G2, etc.
STATCOM	C####_STAT1, C####_STAT2, etc.
HVDC Rectifier	C####_RECT1, C####_ RECT2, etc.
HVDC Inverter	C####_INV1, C####_ INV2, etc.
FACTS Device	C####_FACT1, C####_FACT2, etc.

5.3 Generator Data

This subsection sets out the requirements for modeling a project generator. An aggregated model with one equivalent generator per resource type is expected whenever possible.

Owner Data:

Generator ownership data will be filled in by the NYISO. The submitted .idv may use the default values:

Owner: 1

Fraction: 1

Wind Data:

The plant control mode depends on the type of resource being modeled. Synchronous machines should be in control mode 0 and inverter based generation in control mode 1 or 2.

Control Mode: According to the Following Table:

Table 5.3.1: Generator Control Modes

Resource Type	Control Mode
Synchronous	0 – Not a Wind Machine
Inverter-Based	1 – Standard QT QB Limits 2 – QT QB Limits Based on Wind Power Factor

Plant Data:

The machine should be controlling voltage at the appropriate bus, based on the design of the Project. This should match the bus for voltage control in the stability model.

Scheduled Voltage: The target voltage at the controlled bus, in p.u. Following the design of the facility.

Remote Bus: The bus number at which voltage is controlled (888000-888999). This must match the bus number for voltage control in the stability model.

Machine Data:

The generator should be setup such with all machines at full output, the Project injects its requested ERIS at the POI. For energy storage, with all machines at maximum withdrawal, the Project withdraws its maximum withdrawal from the system amount at the POI. For CSR projects, these are sub-divided by resource type. For example, when all solar units are dispatched at full output, the Project must deliver its solar ERIS allocation at the POI.

Reactive capability shall be based on the planned operating point of the facility, when injecting ERIS at the POI. Note that the project must provide a power factor of +/- 0.95 at the POI (synchronous resources) or the PSU high-side (inverter based resources).

Pgen: The provided .idv should set Pgen to zero (NYISO will dispatch the Project)

Pmin: For energy storage resources, when all units are dispatched to Pmin, the Project's requested charging value is withdrawn from the POI. For non-storage resources, Pmin is either zero, or the minimum operating power (wind units may have a cut-in speed, for example).

Pmax: The maximum real power generation of the unit.

- The generator should be setup such that the Project can inject, at a minimum, its requested ERIS at the POI.
- For CSR projects, these are sub-divided by resource type. For example, when all Solar units are dispatched at full output, the Project must be able to at least deliver its Solar ERIS allocation at the POI.

In general: ERIS + losses = < Pmax (MW) = Nameplate rating

Qmin: The minimum reactive power that the machine will provide according to its characteristics and intended operating point when injecting ERIS. The Generating Facility must meet power factor requirements as outlined in 9.5.1.1 of Appendix 15 to Attachment HH of the NYISO OATT.

Qmax: The maximum reactive power that the machine will provide according to its characteristics and intended operating point when injecting ERIS. The Generating Facility must meet power factor requirements as outlined in 9.5.1.1 of Appendix 15 to Attachment HH of the NYISO OATT.

Mbase: The MVA base for the machine, or total nameplate rating in MVA.

Rsource and Xsource: Equivalent source impedance for the machine in per unit on the base MVA of the machine. R_source=0 and X_source=999 is acceptable for inverter based resources, if the exact impedance is not known.

Basic Data:

Unit ID must be assigned based on resource type. The bus type code must be 2.

Bus Type Code: 2

Machine ID: According to the following Table:

Table 5.3.2: NYISO Unit IDs

Resource Type	Unit ID
Combustion Turbine	CT
Steam Turbine	ST
Nuclear	NU
Solar	S
Hydro	H
Wind	W
Battery Energy Storage	E
Pumped Storage	PS
Flywheel	FW
Biofuel	B
Methane	M
Fuel Cell	FC
Natural Gas	NG
Landfill Gas	LG
Combined Cycle (Oil/Gas)	CC
CSR Combination*	Unit ID
DC Coupled Solar and Storage	CR
DC Coupled Wind and Storage	CW
HSR *	Unit ID
DC Coupled IPR and Storage	HR

*For AC Coupled Resources, model each technology type as its own generator.

Transformer Data:

Implicit transformers within the generator are not allowed in NYISO models.

Rtran (pu): 0

Xtran (pu): 0

5.4 Transformer Data

The GSU is expected to be a two-winding transformer, aggregated for each unit in the case of inverter-based resources. If the GSU is a three-winding transformer, it should be modeled as such.

The PSU is expected to be a two or three winding transformer. If it is three winding, it should be modeled as such.

Owner Data:

Transformer ownership data will be filled in by the NYISO. The submitted .idv may use the default values:

Owner: 1

Fraction: 1

I/O Data:

The NYISO inputs data on I/0 code 1/2/1:

Winding Data I/O code: 1 - Turns ratio (p.u. on bus base kV)

Impedance Data I/O: 2 - Z p.u. (winding kV winding MVA)

Admittance I/O code: 1 – p.u. (system base)

Transformer Impedance Data:

R and X must be provided. For a GSU, these are on the equivalent nameplate MVA rating. For a PSU, these are on the self-cooled MVA rating.

R (p.u.): Winding resistance in per-unit. Calculated on the nameplate MVA for GSUs, and the self-cooled MVA rating for PSUs.

X (p.u.): Winding reactance in per-unit. Calculated on the nameplate MVA for GSUs, and the self-cooled MVA rating for PSUs.

Transformer Normal Ratings Data:

For a GSU transformer, Rate A/B/C are typically modeled as the nameplate MVA. For a PSU (main power) transformer, Rate A/B/C should reflect the 2nd stage cooling rating, if external cooling is available.

For a GSU transformer, the winding MVA is the total nameplate MVA. For a PSU transformer, the winding MVA is the self-cooled rating.

Ratings (MVA): Rate 1, Rate 2, Rate 3 =Nameplate (GSU) or 2nd stage cooling (PSU)

Winding 1 Ratio (pu): No-Load (nominal) Tap for Winding 1, typically 1.0
Winding 2 Ratio (pu): No-Load (nominal) Tap for Winding 2, typically 1.0

Winding MVA: Nameplate (GSU) or self-cooled rating (PSU)

Control Data:

Transformers should be in control mode 0 for fixed taps, or 1 for load tap changing. In the event the Project includes a Phase Angle Regulator, modes 3 and 4 may be used for that Phase Angle Regulator.

Tap positions: The total number of tap positions available to the transformer.

Control Mode: 0 for fixed taps, or 1 for automatic load tap changing.

Controlled Bus: If the transformer has a load tap changer, the bus number at which the voltage is regulated.

R1MAX, R1MIN: The maximum and minimum winding ratio that can be achieved by the tap changer.

Vmax, Vmin: The upper (max) and lower (min) voltage limit for the load tap changer's control.

5.5 Auxiliary Load Data

Auxiliary loads are represented as a constant power load.

Basic Data:

Auxiliary loads will be set to non-scalable.

Scalable: Not Scalable

Grouping Data:

Transformer ownership data will be filled in by the NYISO. The submitted .idv may use the default values:

Area: 1

Owner: 1

Zone: 1

Load Data:

Pload: Active Power of the Auxillary load (MW)

Qload: Reactive Power of the Auxillary load (MVAR)

5.6 Shunt Data

This section details the data required for fixed and switched shunts.

Basic Data:

Adjustment Method: 0 for sequential input order. 1 for nearest combination. Select the option that best fits the intended operation of the shunt.

Control Mode: 0 for fixed shunts; For switched shunts, select from the following table:

Table 5.6.1: Switched Shunt Control Modes

Control Objective	Control Mode
Bus Voltage	1
Generator MVAR Regulation	3
HVDC MVAR Regulation	4
Remote Switched Shunt Regulation	5
Shunt FACT MVAR Regulation	6

Switched Shunt Data:

Vhi: The high voltage (or MVAR percentage for control modes 3-6) limit. If not known, use 1.05 as a default.

Vlow: The high voltage (or MVAR percentage control modes 3-6) limit. If not known, use 0.95 as a default.

Binit: Default output of the shunt in MVAR. Must be a valid switching state.

Block Steps: For each block type, the number of identical switching blocks.

Block MVAR: For each block type, the reactive power provided by that block in MVAR.

5.7 Line Data

This section details the data required for collector feeders and other transmission lines.

Note that collector feeders should be clustered wherever possible, such that each modeled unit has a single feeder.

Owner Data:

Line ownership data will be filled in by the NYISO. The submitted .idv may use the default values:

Owner: 1

Fraction: 1

Branch Data:

Branch data will be entered in per unit on a 100 MVA base.

R: Resistance in per unit on a 100 MVA base

X: Reactance in per unit on a 100 MVA base

B: Total line susceptance in per unit on a 100 MVA base.

Rate 1, Rate 2, Rate 3: Rate A (Normal), Rate B (Long Term Emergency), Rate B (Short Term Emergency) ratings for the line. To be provided as summer ratings in the .idv.

5.8 STATCOM Data

This section details the data required for STATCOMS, which are modeled using the shunt FACTS device model in PSSE.

Basic Data

Device Name: Should follow the template C####_STAT1, C####_STAT2. The NYISO will fill in the cluster number.

Sending Bus Number / Name: Bus number / name for STATCOM bus, must match stability model.

Terminal Bus Number/Name: 0 (Shunt Device)

Control Data

Control Mode : Normal (In -Service)

Owner Data

Owner Data: 1 (Will be filled in by the NYISO)

Shunt Data

Vsend Setpoint: Target Voltage in p.u. Must be within range allowed by plant protection.

Shunt Max (MVA): STATCOM reactive capability in MVA

RMPCt (%): The portion of voltage control at the remote bus, which the STATCOM will provide. Typically 100%

Remote Bus Number / Name: Bus number / name for controlled bus, must match stability model.

Series Data

Not Used for STATCOMS

5.9 SVC Data

SVCs are modeled as generators with no real-power capability.

Owner Data:

Generator ownership data will be filled in by the NYISO. The submitted .idv may use the default values:

Owner: 1

Fraction: 1

Wind Data:

The SVC should be to control mode 0.

Plant Data:

The SVC should be controlling voltage at the appropriate bus, based on the design of the Project. This should match the bus for voltage control in the stability model.

Scheduled Voltage: The target voltage at the controlled bus, in p.u. Following the design of the facility.

Remote Bus: The bus number at which voltage is controlled (888000-888999). This must match the bus number for voltage control in the stability model.

Machine Data:

Pgen: 0

Pmin: 0

Pmax: 0

Qmin: The minimum reactive power capability of the SVC.

Qmax: The maximum reactive power capability of the SVC.

Mbase: The MVA base for the machine, or total MVAR capability of the SVC.

Rsource and Xsource: R_source=0 and X_source=999 is acceptable for SVCs, if the exact impedance is not known.

Basic Data:

Bus Type Code: 2

Machine ID: 1

Transformer Data:

Implicit transformers are not allowed in NYISO models.

Rtran (pu): 0

Xtran (pu): 0

5.10 LCC HVDC Data

This section details the data required for LCC HVDC.

Line Data

Line Name: Follow template: C####_LCC1, C####_LCC2. The NYISO will fill in the cluster number once assigned.

Control Mode: Select Power such that real power flow can be scheduled along the line. If this is not the case, please provide documentation describing how the LCC will be controlled.

Vschedule: The DC line voltage in kV

Setval (MW): 0, the line will be dispatched by the NYISO during case setup.

RDC-Ohm: DC line resistance in Ohms

Rcmp-Ohm: Compounding Resistance, in Ohms

Delti: Margin (p.u.), typically 0

Vc Mode: Voltage below which to switch to current control.

Dcvmin: Minimum compounded DC voltage, typically 0

CCC Imax: Iteration Limit for Solution, typically 20

CCC Accel: Acceleration Factor for Solution, typically 20

Rectifier/Inverter Data:

The rectifier and inverter data fields must be provided separately for the rectifier and the inverter side of the LCC-HVDC.

Bus Number: Bus where the rectifier/inverter is located

Bus Name: Bus name where the rectifier/inverter is located

Measuring Bus: Bus for voltage control

CCC X (ohms): Commutating Capacitor reactance (per bridge) in ohms

Primary Base Voltage: AC base voltage for rectifier/inverter (accounting for rectifier/inverter transformer)

Bridges in Series: The number of commutating bridges in the HVDC, typically 1 or 2 for LCC technology.

Trans Ratio (p.u.): Transformer tap ratio for the rectifier/inverter, typically 1.0

AC Tx From Bus: If rectifier/inverter transformer is explicitly modeled, from bus for the transformer.

Max Firing Angle (deg): The maximum firing angle of the rectifier/inverter, accounting for ignition/extinction delays.

Commutating R: Equivalent resistance for the rectifier/inverter

Tap Setting (pu): Nominal tap for the rectifier/inverter transformer.

Max Tap Setting (pu): Highest tap for the rectifier/inverter transformer.

AC Tx To Bus: If rectifier/inverter transformer is explicitly modeled, to bus for the transformer.

Min Firing Angle (deg): The minimum firing angle of the rectifier/inverter, accounting for ignition/extinction delays.

Commutating X: Equivalent reactance for the rectifier/inverter

Tap Setting (pu): Size of each tap change on the rectifier/inverter transformer.

Min Tap Setting (pu): Lowest tap for the rectifier/inverter transformer.

AC Tx To Bus: If rectifier/inverter transformer is explicitly modeled, circuit ID for the transformer.

5.11 VSC HVDC Data

This section details the data required for VSC HVDC.

Line Data

Line Name: Follow template: C####_VSC1, C####_VSC2. The NYISO will fill in the cluster number once assigned.

Control Mode: In-Service

Owner Data: 1 by default, the NYISO will fill this in.

Rdc (Ohms): DC Line Resistance in Ohms

Converter Data

The following must be specified for Converter 1 and Converter 2.

Bus Number/Name: Number/Name of the rectifier/inverter bus

DC Control Type: Either kV (Line Voltage) or MW (DC Line Power). For most applications, it is anticipated that one converter will be in each of these two control modes.

AC Control Mode: Either voltage or power factor. Voltage mode is anticipated for most applications.

AC Current Rating (A): Maximum converter rating in amps.

PWR Weighting Factor: Priority for Active/Reactive power. 1.0 (P priority) be default.

RMPCT (%): For the controlled bus, the percentage of total reactive compensation that the VSC will provide. 100% by default.

DC Setpoint (kV/MW): For a converter on DC Control Type “kV”, this should be the nominal DC line voltage. For a converter on DC Control Type “MW”, this should be 0, and the NYISO will schedule the line during dispatch.

AC Setpoint (p.u.): For a converter on AC Control Mode “Voltage” this should be the desired voltage at the controlled bus. This voltage must be within the limits of the Project’s protection.

MVA Rating: Nameplate rating of the converter in MVA

Max Q (MVAR): Maximum Lagging Reactive Power for Converter (Account for Harmonic Filters if not explicitly Modeled). Note that the Generating Facility must meet the power factor requirements outlined in 9.5.1.1 of Appendix 15 to Attachment HH of the NYISO OATT.

Min Q (MVAR): Maximum Leading Reactive Power for Converter (Account for Harmonic Filters if not explicitly Modeled). Note that the Generating Facility must meet the power factor requirements outlined in 9.5.1.1 of Appendix 15 to Attachment HH of the NYISO OATT.

Remote Bus Number: Bus number for voltage control. Must match the provided stability model.

A Loss (kW): Static Loss in kW (Converter Losses)

B Loss (kW/A): Linear loss coefficient (Converter Losses)

Min Conv Loss: Minimum Converter Loss (At least as high as A Loss)

5.12 Special Considerations for Multi-Unit Facilities

Projects proposing to interconnect with multiple Generating Faciities (*e.g.*, CSR or HSR) must request ERIS for each Generator.

- When each unit of the intermittent power resource is dispatched to the maximum, the ERIS of the intermittent power resource should be injected at the POI.
- When each unit of the storage resource is dispatched to the maximum, the ERIS of the storage resource should be injected at the POI.
- When each unit of the storage resource is dispatched to the minimum, the requested withdrawal amount of the storage resource should be withdrawn from the POI.

For NYISO's identification, the generator bus names should follow the following special convention:

C####_CSR_ID

Where NYISO will fill in the cluster number, and the customer will replace "ID" with the unit ID for that resource. For example, a solar generator bus would be named "C####_CSR_S".

6. Short Circuit Modeling Requirements

This section details the requirements for short circuit (ASPEN Oneliner™) models submitted to the NYISO in the cluster study process.

A short circuit model consists of the following:

- A .olr file with the Project represented. This must be compatible with ASPEN Oneliner™ version 15.7.
- A .chf file that adds the Project to an existing case. This must be compatible with ASPEN Oneliner™ version 15.7.

The remainder of this section details the data requirements and expected performance for a short circuit model.

a. General Considerations for Short Circuit

Inverter based generators should be modeled as VCCS, injecting reactive current only, following the guidelines set forth in ASPEN Oneliner™ Help Contents Appendix K2. See Section 8 of this document for details on short circuit model testing.

Synchronous machines should be modeled as conventional generation.

Per the NYISO Transmission Expansion and Interconnection ("TEI") Manual, loads and shunts are ignored in short circuit and should be excluded from the model.

NYISO's solution settings for ASPEN are provided below in Table 6.1.1:

Table 6.1.1: NYISO Short Circuit Settings

FIELD	SELECTION SETTINGS
Prefault voltage	From a linear network solution
Generator Impedance	Subtransient
Define Fault MVA as product of	Current & prefault voltage
Ignore in Short Circuits	Loads Transmission line G+jB Shunts with + seq values
MOV-Protected series Capacitor	Unchecked
Current Limited generators	Enforce current limit A
Simulate converter interfaced resources	Yes
Simulate voltage-Controlled current sources	Yes

A check will be performed to ensure the Project model injects fault current into a 1 phase, 2 phase and 3 phase to ground fault at the POI. The Project must create no Network Anomalies.

b. Conventional Generator Data (for Synchronous Resources)

This subsection outlines the necessary data for a conventional generator model.

Internal V Source

p.u: 1

Ref. Angle:

Current Limits (A)

A: 1/X’’ or the maximum fault current for the machine.

B: 1/X’’ or the maximum fault current for the machine.

Power Flow Regulation

Radio Button: Default – Regulates Voltage

Hold V: 1 p.u.

At: Generator terminal bus or other controlled bus as applicable.

Generating Unit Info

Unit ID: Follow Table 5.3.2.

Unit Rating: Machine nameplate MVA

Impedances: All impedances to be supplied in per unit on the Machine’s nameplate MVA, including the following:

- Subtransient: X’’
- Transient: X’
- Synchronous: X_0
- Negative Sequence: X1
- Zero Sequence: X0

Neutral Impedance (in actual Ohms): Neutral impedance of the machine. 999 if ungrounded.

Scheduled Generation: Both P and Q are set to 0 for short circuit.

P and Q Limits: Should match steady state data.

c. VCCS Data (for Inverter Based Resources)

This subsection outlines the necessary data for a VCCS model.

MVA Rating: Total nameplate MVA of all inverters represented by the equivalent VCCS

Pos. Sequence Voltage Measured at: Select “Device Terminal” or “Network side of transformer” as appropriate based on intended design.

Limits on Terminal Voltages:

- Max: 1.05, or maximum voltage allowed by protection
- Min: 0 (see NERC PRC-024)

Main Data Table

The main data table represents a current-voltage characteristic for the equivalent VCCS model. Each row represents a voltage and the current the resource will inject at that voltage (this current must be purely reactive – see ASPEN Oneliner™ Help Contents Appendix K2).

Table 6.3.1 shows an example of a VCCS model that meets these requirements. The model for a Project must be based on the real characteristics of the inverters and scaled based on the number of inverters represented by the equivalent VCCS.

Table 6.3.1: Sample VCCS Table for an Inverter Based Resource

Voltage (p.u.	Current (A)	Angle (deg)
1.0	0	-90
0.5	500	-90
0.2	450	-90

d. Bus Data

This subsection outlines the necessary data for each bus in the short circuit model. Breaker data is not required.

Name: A bus name following the convention laid out in Table 5.2.1

Bus no: A bus number between 888000 and 888999. This should match the same bus number in the steady state model.

Location: Not required.

Nominal kV: Base voltage for the bus in kV

Area number: Default to 1, the NYISO will fill this field.

Zone no: Default to 1, the NYISO will fill this field.

DistriView Substation Group no: Not required.

Bus Type: Leave all boxes unchecked

e. Transformer Data

This subsection outlines the necessary data for each transformer in the short circuit model. Transformers should be modeled using their exact winding configuration (2 or 3 winding, with proper vector group and clock position).

Two Winding Transformers

Name: Use format C###_GSU1, C####_GSU2, etc. for GSU transformers and C####_PSU1, C####PSU2, etc. for PSU transformers.

Ckt ID: Use ID 1 unless there are multiple branches between the same two busses.

MVA 1,2,3:

- For GSU transformers, each of these is equal to the aggregate nameplate MVA
- For PSU transformers, each of these is equal to the highest available cooling rating.

MVA Base:

- For GSU transformers, equal to the aggregate nameplate MVA
- For PSU transformers, equal to the self cooled rating.

Vector Group: Specify the proper vector group for the transformer. This should match the oneline diagram. Ensure that the “Neutral Ground Z (Ohms)” fields are filled out for proper grounding configuration.

Impedance Values:

- R1: Positive sequence winding resistance in p.u. on MVA base
- X1: Positive sequence winding reactance in p.u. on MVA base
- R0: Zero sequence winding resistance in p.u. on MVA base
    - For transformers that are an open circuit in the zero sequence, simply copy the positive sequence impedance here.
- X0: Zero sequence winding reactance in p.u. on MVA base
    - For transformers that are an open circuit in the zero sequence, simply copy the positive sequence impedance here.

Admittance Values: Not used in NYISO short circuit simulations. B and G values can be left blank.

Three Winding Transformers

Name: Use format C###_GSU1, C####_GSU2, etc. for GSU transformers and C####_PSU1, C####PSU2, etc. for PSU transformers.

Ckt ID: Use ID 1 unless there are multiple branches between the same two busses.

MVA 1,2,3:

- For GSU transformers, each of these is equal to the aggregate nameplate MVA
- For PSU transformers, each of these is equal to the highest available cooling rating.

MVA Base:

- For GSU transformers, equal to the aggregate nameplate MVA
- For PSU transformers, equal to the self-cooled rating.

Vector Group: Specify the proper vector group for the transformer. This should match the oneline diagram. Ensure that the “Neutral Ground Z (Ohms)” fields are filled out for proper grounding configuration.

Positive Sequence Impedance Values:

- Zps: The winding resistance and reactance for the primary-secondary winding in p.u. on the MVA base of the transformer.
- Zpt: The winding resistance and reactance for the primary-tertiary winding in p.u. on the MVA base of the transformer.
- Zst: The winding resistance and reactance for the secondary-tertiary winding in p.u. on the MVA base of the transformer.

Zero Sequence Impedance Values:

- Select “Short Circuit Impedances”
- Zps: The winding resistance and reactance for the primary-secondary winding in p.u. on the MVA base of the transformer.
    - For windings that are an open circuit in the zero sequence, simply copy the positive sequence impedance here.
- Zpt: The winding resistance and reactance for the primary-tertiary winding in p.u. on the MVA base of the transformer.
    - For windings that are an open circuit in the zero sequence, simply copy the positive sequence impedance here.
- Zst: The winding resistance and reactance for the secondary-tertiary winding in p.u. on the MVA base of the transformer.
    - For windings that are an open circuit in the zero sequence, simply copy the positive sequence impedance here.

Magnetizing Susceptances: Not required.

f. Line Data

This subsection outlines the necessary data for each line in the short circuit model.

Name: Use format C###_COL1, C####_COL2, etc. for collector feeders and C####_Gentie1, C####_Gentie 2, etc. for gen tie lines.

Ckt ID: Use ID 1 unless there are multiple branches between the same two busses.

Length: Line Length in miles.

Branch Parameters:

- R1: Positive sequence line resistance in p.u. on MVA base
- X1: Positive sequence line reactance in p.u. on MVA base
- R0: Zero sequence line resistance in p.u. on MVA base
- X0: Zero sequence line reactance in p.u. on MVA base
- G1: Not required
- G10: Not required
- G2: Not required
- G20: Not required
- B1: Enter half the total line charging susceptance.
- B10: Enter half the total zero sequence line charging susceptance if known. If not, enter half the total line charging susceptance.
- B2: Enter half the total line charging susceptance.
- B20: Enter half the total zero sequence line charging susceptance if known. If not, enter half the total line charging susceptance.

Current Ratings: Not required for short circuit model.

g. FACTS Devices

Shunt FACTS are not required to be modeled in ASPEN Oneliner™, with the exception of STATCOMs.

STATCOMS:

STATCOMs should be modeled as a VCCS in such a way that they do not inject real current, keeping in mind that ASPEN interpolates between entered current values.

MVA Rating: STACOM nameplate MVA

Pos. Sequence Voltage Measured at: Select “Device Terminal” or “Network side of transformer” as appropriate based on intended design.

Limits on Terminal Voltages:

- Max: 1.05, or maximum voltage allowed by protection
- Min: 0, or minimum voltage allowed by protection

Main Data Table

The main data table represents a current-voltage characteristic for the equivalent VCCS model. Each row represents a voltage and the current the resource will inject at that voltage (this current must be purely reactive – see ASPEN Oneliner™ Help Contents Appendix K2).

Table 6.7.1 shows an example of a VCCS STATCOM model that meets these requirements. The model for a Project must be based on the control characteristics of the STATCOM.

Table 6.7.1: Sample VCCS Table for a STATCOM

Voltage (p.u.)	Current (A)	Angle (deg)
1.10	500	90
1.05	0	90
1.0	0	-90
0.95	0	-90
0.9	500	-90
0.1	500	-90

h. Special Considerations for HVDC Projects

Each end of an HVDC project should be modeled by a VCCS, including appropriate rectifier/inverter transformers.

For a point to point application, the model includes:

- The rectifier transformer.
- A VCCS representing the rectifier.
- The inverter transformer.
- A VCCS representing the inverter.

For a wind park application, the offshore wind facility does not need to be represented in ASPEN, provided it makes no AC connection to the grid. The model would then include:

- The inverter transformer.
- A VCCS representing the inverter.

7. Stability Modeling Requirements

This section details the requirements for stability (PSSE) models submitted to the NYISO in the cluster study process.

A stability model consists of the following:

- A .dyr file with dynamic models for the Project and all Project protection. This must be compatible with PSSE version 35.3.3.
    - Projects will be modeled using PSSE standard library models.
    - In the case that no standard library model is available, a documented exception can be made with the following:
        - Written documentation demonstrating that the particular project cannot be represented by a standard library model.
        - A user written model consisting of a .dyr file, a .dll file, other supporting files such as a umf/userpar file as applicable, and the uncompiled source code as available. This model must be of a model series already accepted by the MMWG.

The remainder of this section details the data requirements and expected performance for a stability model.

a. General Considerations

All stability models submitted to the NYISO should use PSSE standard library models wherever possible.

Model Usability will be assessed under the criteria outlined in Section 8 of this document.

b. Typical Model Structure (Inverter-Based)

A model for an inverter based resource includes Protection, a Generator Model, an Electrical Control Model, a Plant Control Model, and Other models as applicable.

The following table outlines typical models used for each resource. This table is non-comprehensive, and there are many more standard library models available.

Table 7.2.1: Typical Stability Models for Inverter Based Resources

	Item	Acceptable Range/Verificaiton Method
Protection Models (VTGTPAT and FRQTPAT)	Number of Protection Models	Every Unit should have at the minimum: High Voltage Protection, Low Frequency Protection, High Frequency Protection, Low Voltage Protection
	Protection Model Values	Must Comply With PRC-024. If in LIPA, must meet LIPA ride-through requirements outlined in *PSEG-LI Statement for Performance Requirements for Transmission Connected Resources Using Non-Synchronous Generation*
	Model	**Acceptable Resources**
Typical Models (Generator)	REGCA1	Any Inverter Based
	REGCAU2	Any Inverter Based
	WT3G1	Type 3 Wind
	WT3G2	Type 3 Wind
	Model	**Acceptable Resources**
Typical Models (Electrical Control)	REECA1	Any Inverter Based Except Battery
	REECB1	Solar
	REECCU1	Battery
	WT3E1	Type 3 Wind
	Model	**Acceptable Resources**
Typical Models (Plant Control)	REPCA1	Any Inverter Based or Type 3 Wind
	REAX3BU1	Type 3 Wind w/ Many Machines in model
	REAX4BU1	Any Inverter Based w/ Many Machines in model
	Model	**Acceptable Resources**
Typical Models (Other)	PLNTBU1	Plant control for CSR or multiple machines
	SVSMO3T2	STATCOM

c. Typical Model Structure (Synchronous)

A model for a synchronous resource includes Protection, a Generator Model, a Governor Model, an Exciter Model, and a Stabilizer model as applicable.

The following table outlines typical models used for each resource. This table is non-comprehensive, and there are many more standard library models available. Note that several simplified models are not recommended under NERC Modeling Notification Process Documents.

Table 7.3.1: Typical Stability Models for Synchronous Resources

	Item	Acceptable Range/Verificaiton Method
Protection Models (VTGTPAT and FRQTPAT)	Number of Protection Models	Every Unit should have at the minimum: High Voltage Protection, Low Frequency Protection, High Frequency Protection, Low Voltage Protection
	Protection Model Values	Must Comply With PRC-024.
	Model	**Acceptable Resources**
Typical Models (Generator)	GENTPJ	Round rotor synchronous machines (Usually Hydro)
	GENTPJ	Salient pole synchronous machines (Usually Gas / CC)
	Many others used in practice.*	
	Model	**Acceptable Resources**
Typical Models (Governor)	GGOV1	Any synchronous machine
	Many others used in practice.*	
	Model	**Stipulation**
Disallowed Models (Excitation)	Do not use -> SEXS	A more accurate exciter model should be provided
	Do not use -> EX2000*	A more accurate exciter model should be provided
	Many detailed acceptable models used in practice.*	
	Model	**Stipulation**
Typical Models (Stabilizer)	Many stabilizer models used in practice.	

*Several simplified models are not recommended under NERC modeling Notifications. See: https://www.nerc.com/comm/PC/Pages/System-Analysis-and-Modeling-Subcommittee-(SAMS)-2013.aspx

8. Model Usability Testing

8.1 Procedures and Criteria for Dynamic Models

Stability models are tested via two test faults and several parameter checks.

The performance of the Project and the surrounding system are evaluated to determine whether or not the model is acceptable.

Four sets of criteria are presented in this section:

1. Criteria for the 20-second flat run test
2. Criteria for the 9-cycle 3-phase fault test
3. Protection Criteria
4. Primary Frequency Response and Droop Criteria

In addition, where certain CTOs have more stringent requirements, such requirements will be checked as described in section 8.1.5 of this document.

8.1.1 Case Setup

The Project will be added in steady state to the SUM CBA case, or to the latest SUM CPA case that includes projects which have met cluster inclusion milestones.

If such a case is not available for the transitional cluster study, the latest available SUM FERC-715 filing case will be used.

The Project will be dispatched against conventional generation where possible to build this case. The case will then be converted to a .CNV file.

The Project's .DYR file will be incorporated into the .SNP file for the dynamics package associated with the used base case.

8.1.2 Procedures and Criteria for the 20-second flat run test.

A 20 second no fault test is run in accordance with the MMWG Procedural Manual. To perform this test, the following steps are carried out:

1. The case is initialized and run to 0.1 seconds.
2. The simulation is run to 20 seconds without applying any disturbance.
3. The case is saved at t = 20 seconds.

The 20 second no fault test will be considered passed if the following conditions hold for all Project generators. The Project must also not adversely impact the performance of nearby units.

1. **No generator's real power changes by 0.1 MW or more.**
    a. The comparison shall be made between t = 0 and t = 20 seconds
    b. If generators other than the project are changing, the test will be considered passed if the same change occurs in the base case.
2. **No generator's reactive power changes by 0.1 MVAR or more.**
    a. The comparison shall be made between t = 0 and t = 20 seconds
    b. If generators other than the project are changing, the test will be considered passed if the same change occurs in the base case.
3. **No synchronous generator's angle changes by more than 0.1 degrees.**
    a. The comparison shall be made between t = 0 and t = 20 seconds
    b. If generators other than the project are changing, the test will be considered passed if the same change occurs in the base case.
4. **No unit shall trip during the simulation.**
    a. No exceptions.
5. **The initial TYSL solution in PSSE must converge.**
    a. The solution should converge in at most 3 iterations.
6. **The Project models do not have any suspect DSTATES during initialization.**
7. **The Project models converge within one solution iteration following the 0.1 second initialization period.**

8.1.3 Procedures and Criteria for the 9-cycle 3-phase fault test:

A 9-cycle, 3-phase fault test is run to verify ride through performance and the Project's ability to return to its initial active power. To perform this test, the following steps are carried out:

1. The case is initialized.
2. The simulation is run to 0.1 seconds without applying any disturbance.
3. A three-phase fault is added at the Project's POI bus.
4. The simulation is run for 9 cycles (0.15 seconds).*
5. The fault is removed without opening any element.
6. The simulation is run to a total simulation time of 60 seconds.

* If the CCT of the POI bus is less than 9 cycles, this test will be run up to that CCT

The 9-cycle 3-phase fault test will be considered passed if the following conditions hold:

1. **No generator's real power changes by 1.0 MW or more.**
    a. The comparison shall be made between t = 0 and t = 60 seconds
    b. If generators other than the project are changing, the test will be considered passed if the same change occurs in the base case.
2. **No generator's reactive power changes by 1.0 MVAR or more.**
    a. The comparison shall be made between t = 0 and t = 60 seconds
    b. If generators other than the project are changing, the test will be considered passed if the same change occurs in the base case.
    c. Exciters with dead band control are exempt from this requirement.
3. **No unit tripping.**

   a. The project must not trip.
   b. If generators other than the project trip, the test may be considered passed in some instances if the same trip occurs in the base case.
4. **System shall be stable.**
   a. No unit or group of units has lost synchronism.
   b. Angular stability should be evident at t = 60 seconds.
5. **Generator voltages return to at least 0.9 p.u. within 5 seconds after the fault is cleared.**

8.1.4 NERC PRC-024 Protection Settings Criteria

NERC PRC-024-3 [4] specifies minimum requirements for Project protection. The standard establishes “no-trip” zones for voltage and frequency excursions, establishing a minimum ride-through requirement.

The protection settings in a Project’s .DYR file will be checked for compliance with this standard. The Project’s protection settings must reflect the actual settings intended to be used in the plant based on its design and capability. The protection settings should not try to mimic the specified minimum requirements.

8.1.4.1: PRC-024 Voltage Requirements

The voltage requirements in PRC-024 are broken out into low and high voltage times:

- For low voltages, the time provided is the minimum time for which the unit must remain online when the voltage at its PSU (high side) is below the value specified.
- For high voltages, the time provided is the minimum time for which the unit must remain online when the voltage at its PSU (high side) is above the value specified.
- Many protection models are specified at the inverter terminal, rather than the PSU high side. When PRC-024 is checked, an assumption is made that the terminal and PSU voltage are close.

Table 8.1.4.1.1 shows the PRC-024 voltage ride through requirements for the Eastern Interconnection as of revision 3 [4]:

Table 8.1.4.1.1: NERC PRC-024-3 Voltage Ride Through Requirements (For Eastern, Western, and ERCOT Interconnections)

High Voltage Duration		Low Voltage Duration	
Voltage (pu)	Minimum Time (sec)	Voltage (pu)	Minimum Time (sec)
≥1.200	0.00	<0.45	0.15
≥1.175	0.20	<0.65	0.30
≥1.15	0.50	<0.75	2.00
≥1.10	1.00	<0.90	3.00
<1.10	4.00	≥ 0.90	4.00

Protection settings that trip before the specified minimum time are considered to be within the "No trip zone". For example, if a relay is set at 0.5 p.u. voltage, the applicable requirement is 0.3 seconds for voltages under 0.65 p.u. Therefore, a trip time of 0.4 seconds would be compliant, and a setting of 0.2 seconds would be non-compliant.

Figure 8.1.4.1.1 shows the no-trip zone on a time-voltage curve:

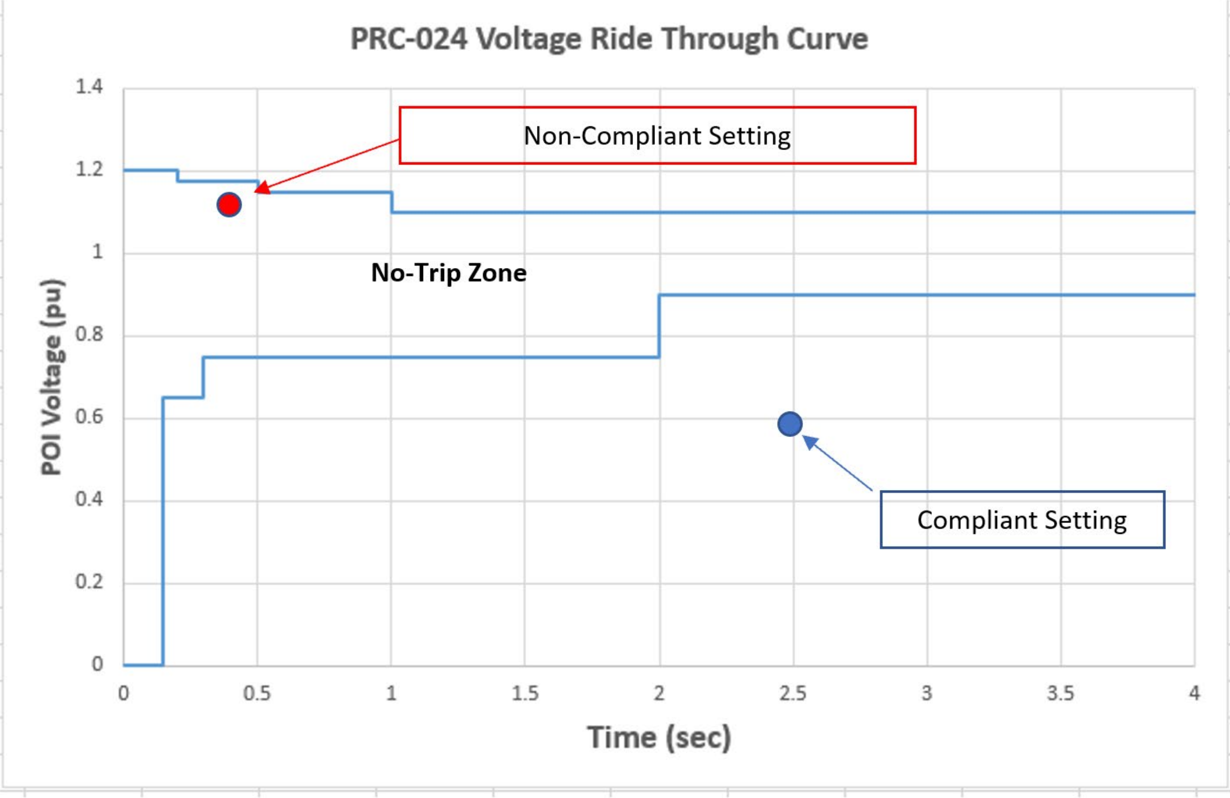

Figure 8.1.4.1.1: Voltage Ride Through Curve with No-Trip Zone and Sample Settings

8.1.4.2: PRC-024 Frequency Requirements

The frequency requirements in PRC-024 are broken out into under and over frequency times:

- For low frequency, the time provided is the minimum time for which the unit must remain on line when the frequency at its PSU (high side) is below the value specified.
- For high frequency, the time provided is the minimum time for which the unit must remain on line when the frequency at its PSU (high side) is above the value specified.
- Many protection models are specified at the inverter terminal. When PRC-024 is checked. an assumption is made that the terminal and PSU frequency are close.

Table 8.1.4.2.1 shows the PRC-024 frequency ride through requirements for the Eastern Interconnection as of revision 3 [4]:

Table 8.1.4.2.1: NERC PRC-024-3 Frequency Ride Through Requirements (For Eastern Interconnection)

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	**Minimum Time (Sec)**	**Frequency (Hz)**	**Minimum Time (sec)**
≥61.8	Instantaneous[9]	≤57.8	Instantaneous[9]
≥60.5	$10^{(90.935-1.45713*f)}$	≤59.5	$10^{(1.7373*f-100.116)}$
<60.5	Continuous operation	> 59.5	Continuous operation

Protection settings that trip before the specified minimum time are considered to be within the “No trip zone”. For example, if a relay is set at 61 Hz, the applicable requirement is calculated using the equation in Table 8.1.4.2.1 for frequencies between 60.5 Hz and 61.8 Hz. Substituting 61 for “f” gives a minimum ride-through of 112 seconds Therefore, a trip time of 120 seconds would be compliant, and a setting of 100 seconds would be non-compliant.

Figure 8.1.4.2.1 shows the no-trip zone on a time-frequency curve.

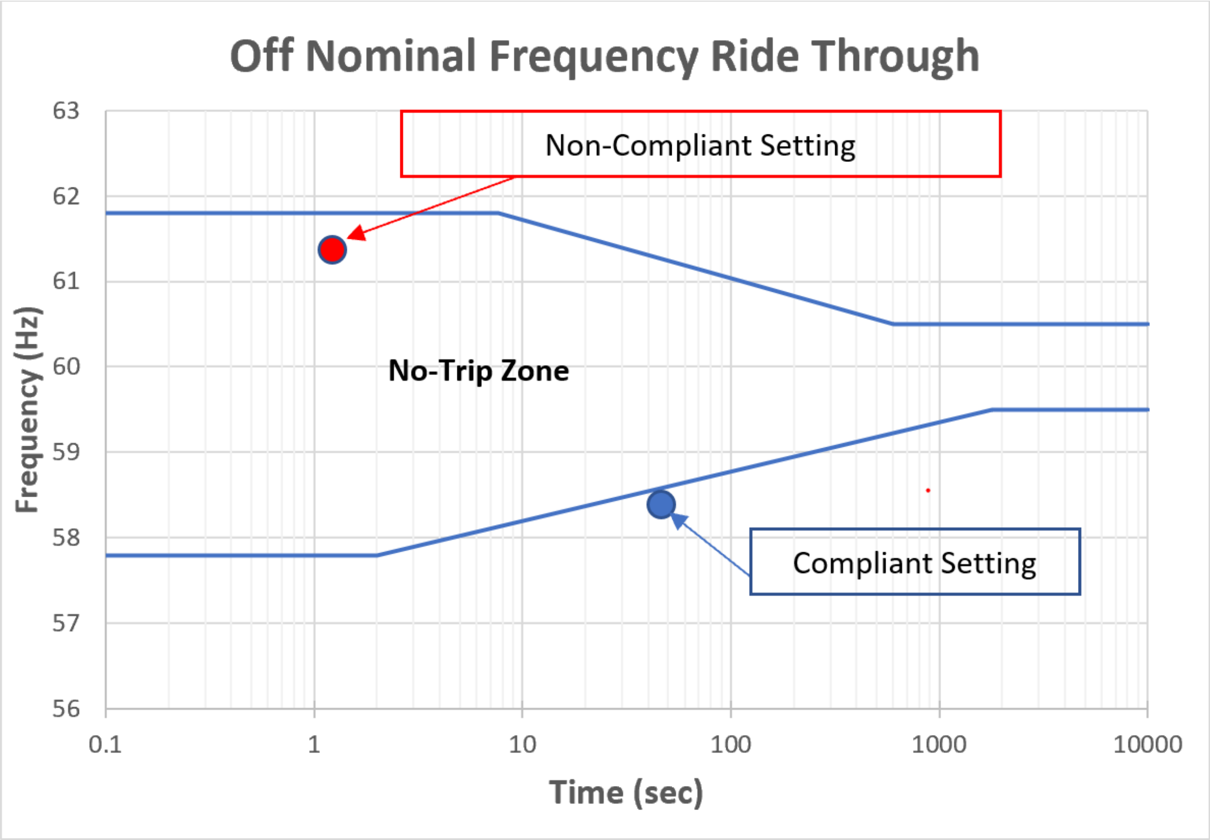

Figure 8.1.4.2.1: Frequency Ride Through Curve with No-Trip Zone and Sample Settings

8.1.5 TO Specific Criteria for Fault Ride-Through Performance and Protection

Some TO's have specific fault ride-through requirements for non-synchronous resources. The protection settings for the Project will be checked against the requirements of the CTO.

8.1.5.1: LIPA Dynamic Requirements

LIPA dynamic Requirements are detailed in "PSEG-LI Performance Requirements for Transmission-Connected Non-Synchronous Resources" [2].

LIPA's dynamic requirements will be evaluated in the Project's response to the 9 cycle-3 phase fault, as applicable (see section 4.3). Checks performed by the NYISO are listed here:

Reactive current shall be injected in a smooth manner (without steps or discontinuities with a linear reduction in terminal voltage).

The Project shall smoothly recover to 90% of its pre-fault active power output, at a specified active power recovery rate following the 9-cycle 3 phase fault.

Active power recovery shall begin no later than 20 msec after the point-of-interconnection voltage reaches 0.90 per-unit of the positive-sequence nominal voltage.
The specified active power recovery rate must be in a range of 0.1-10 p.u. per second.

Synchronous machine PSU voltages within LIPA shall recover to 0.65 p.u, within 0.4 seconds.

8.1.5.2: LIPA Protection Requirements

The LIPA system has a more stringent set of protection requirements than those required by NERC PRC-024 with larger "No-Trip Zones". LIPA's requirements for inverter-based resources and type-3 wind are set forth in "Performance Requirements for Non-Synchronous Generation" [2].

Note that PSEG-LI specifies several sub-cycle requirements, which are not checked in interconnection studies as PSSE is a positive sequence fundamental frequency software.

Table 8.1.5.2.1 shows the effective PSEG-LI voltage ride through requirements.

Table 8.1.5.2.1: LIPA Voltage Ride Through Requirements

High Voltage		Low Voltage	
Voltage (p.u.)	Minimum Trip Time (Sec) (Cumulative)	Voltage (p.u.)	Minimum Trip Time (Sec) (Cumulative)
>1.7	0.0002**	<0.25	0.16
>1.6	0.001**	<0.5	1.2
>1.4	0.003**	<0.7	2.4
>1.2	0.015***	<0.9	3

** Less than 1 cycle, and not typically modeled in PSSE.
***0.015 is close enough to 1 cycle for testing in PSSE.

From the table, note that LIPA does not specify high-voltage ride through for voltages below 1.2. In this case, PRC-024 applies. The effective LIPA no-trip zone for voltage is shown in Figure 8.1.5.2.1:

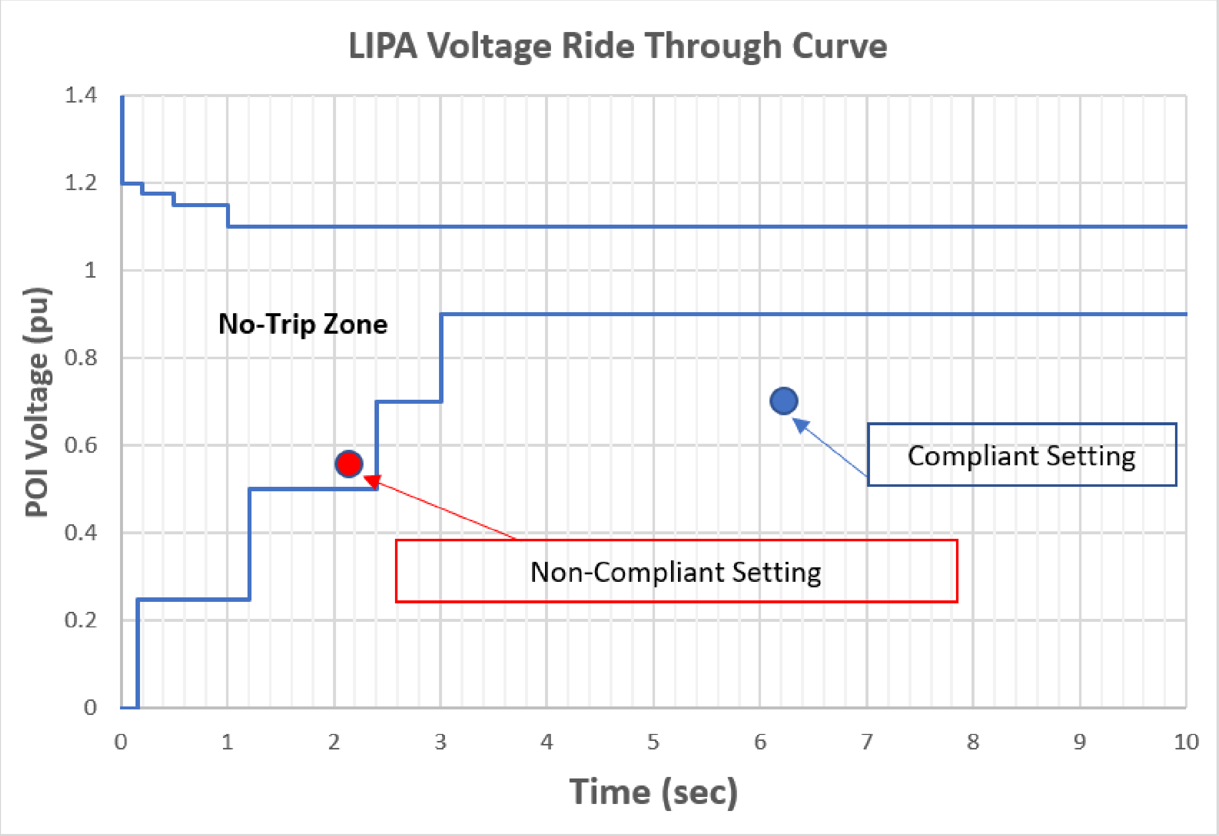

Figure 8.1.5.2.1: LIPA Voltage Ride Through Curve with No-Trip Zone and Sample Settings

The LIPA frequency requirements are more stringent than NERC PRC-024, and act as cumulative requirements measuring the frequency at the POI. Table 8.1.5.2.2. summarizes the under and over frequency requirements.

Table 8.1.5.2.2: LIPA Frequency Ride Through Requirements

Frequency Range (Hz)	Cumulative Duration (seconds)
f > 61.8	may trip
61.8 - 61.2	300 sec
61.2 - 58.8	continuous
58.8 - 57.0	300 sec
f < 57.0	may trip

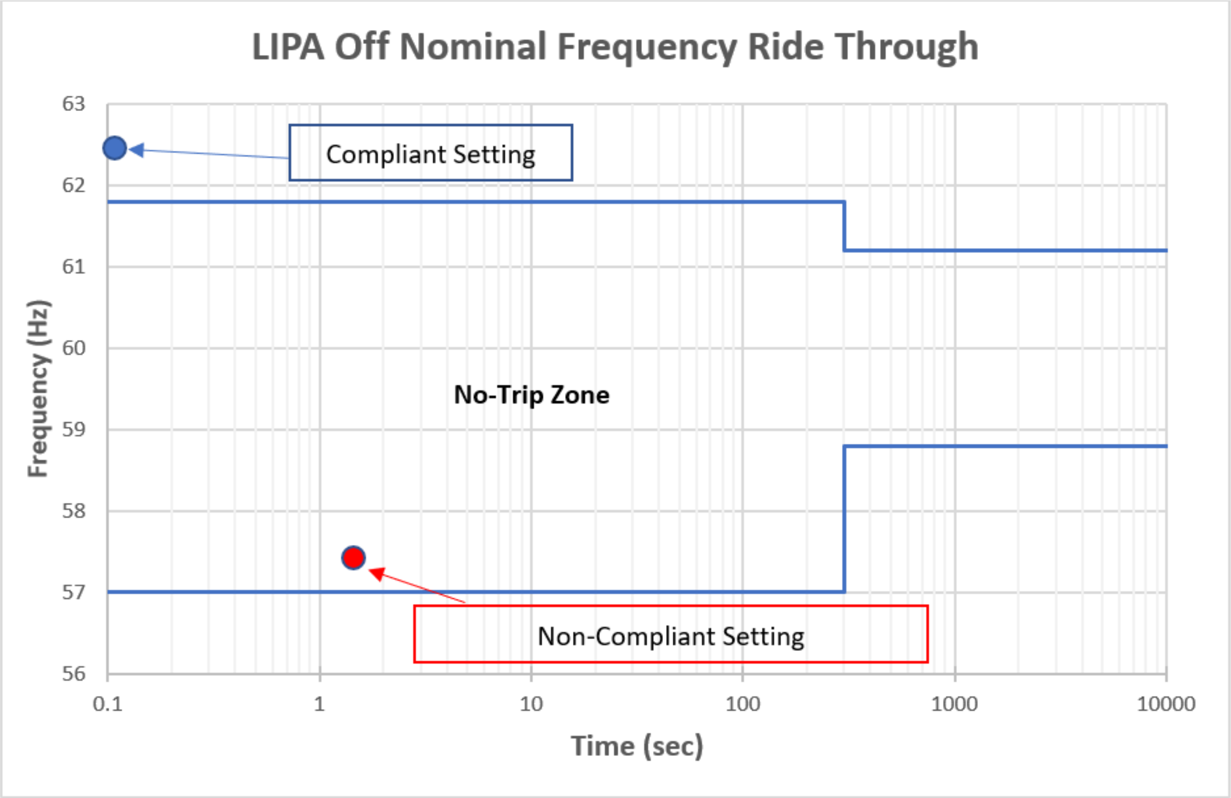

Figure 8.1.5.2.2: LIPA Frequency Ride Through Curve with No-Trip Zone and Sample Settings

8.1.6 Criteria for Primary Frequency Response, Droop, and Deadband

The Project's .DYR file will be checked for compliance with the Primary Frequency Response, Droop, and Deadband requirements established in the pro-forma interconnection agreement (Section 9.5.2 of Appendix 15 to Attachment HH).

Table 8.1.6.1 lays out the requirements for each parameter:

Table 8.1.6.1: Frequency Control Requirements

Performance Requirement	Criteria	Check Performed
Primary Frequency Response	Frequency control must be enabled	Flags will be checked in the in the Governor (conventional) or Plant Control Model (inverter-based).
Droop	Maximum of 5% Droop	Checked in the Governor (conventional) or Plant Control Model (inverter-based). For generic renewable plant control, parameters

		Ddn and Dup are 20 or higher.
Frequency Deadband	+/- 0.036 Hz or Less	Checked in the Governor (conventional) or Plant Control Model (inverter-based). For generic renewable plant control, parameter fdbd1 is between -0.006 and zero. For generic renewable plant control, parameter fdbd2 is between zero and 0.006

8.2 Procedures and Criteria for Short Circuit Models

Short circuit models are tested via three test faults and several parameter checks.

The performance of the Project is evaluated to determine whether or not the model is acceptable.

Two sets of criteria are presented in this section:

1. Criteria for POI fault testing
2. Criteria for VCCS parameters (IBR only)

8.2.1 Criteria for fault response

Short circuit models should demonstrate reactive current injection into each of the following zero-impedance (bolted) faults, applied at the POI:

- Single Phase to Ground
- Two Phase to Ground
- Three Phase to Ground

The project model shall not trip (inject a zero current) for any of these fault simulations.

8.2.2 Criteria for VCCS Parameters (IBR only)

The VCCS parameters of the model will be checked to ensure that the following criteria are met:

- Only reactive current is injected by the Project model.

    - See ASPEN Oneliner™ Help Contents Appendix.2
- The Project model does not shut down on low voltage.
    - Either the minimum limit on terminal voltage is zero, or the “Shut down based on min phase voltage” box is unchecked.

9. References

1. PSSE Model Library (Help -> PSSE Documentation -> Model Library)
2. NERC PRC 024-03
3. NYISO OATT Attachment HH
4. ASPEN Oneliner™ Help Contents Appendix K2
5. NYISO TEI Manual
6. PSEG-LI Statement for Performance Requirements for Transmission Connected Resources Using Non-Synchronous Generation
7. NERC Modeling Notifications: https://www.nerc.com/comm/PC/Pages/System-Analysis-and-Modeling-Subcommittee-(SAMS)-2013.aspx