PSEG Long Island's DER Interconnection Technical Requirements Document

Long Island Interconnection Working Group Meeting
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Disclaimer

Requirements for interconnection of DER to the LIPA system are defined in the *PSEG Long Island's Smart Grid Small Generator Interconnection Technical Requirements and Screening Criteria for Operating in Parallel with LIPA's Distribution System* document, as currently published. This presentation is intended to be informative, only, and does not modify, supplement, or interpret the requirement document as currently published.

Scope and Purpose of Document

- Clearly define LIPA system performance objectives that are the basis for DER requirements
- Define screening and study scopes to evaluate proposed DER interconnection consistency with system performance objectives
- Specify details of technical interconnection design requirements that will protect the reliability, safety, security, system equipment integrity, power quality of the LIPA system and the property of other customers
- Provide reasonable accommodation of DER

Document Outline

1. Scope and purpose
2. Definitions
3. Distribution system performance standards
4. Preliminary DER interconnection screening
5. Supplemental interconnection screening
6. Coordinated Electric System Interconnection Review (CESIR)
7. Interconnection design requirements (DER ≤ 500 kVA)
8. Interconnection design requirements (DER > 500 kVA)
9. DER interconnection commissioning and testing
10. DER system operation

Appendices

A. Determination of DER penetration levels
B. Supplemental screening calculations
C. Ground sources
D. Example diagrams

Distribution System Performance Standards

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Distribution System Performance Standards

- Applicable system conditions
  - Contingencies (N and N-1)
  - Load level
  - Output levels of DER (proposed and existing)
- Design basis events and contingencies
  - Concurrent variation in output of all connected DER with reasonable consideration of geospatial diversity
  - Short-circuit and open-circuit faults of any type
  - Operation of any LIPA system interruption device with/without fault
  - Spontaneous clearing of any short-circuit fault
  - Isolation of primary substation from transmission supply

Distribution System Performance Standards (cont'd)

- Circuit capacity – design to supply forecast load demand without consideration of DER, unless DER is contracted for firm service
- Steady state voltage within ANSI C84.1 Range A for all customers
  - Temporary deviation acceptable until corrected by LTC or cap switching as long as Range B is not exceeded
  - Can go to Range B if served by a dedicated transformer
  - PCC of primary metered customer must remain in Range A
- Primary voltages within range of 0.97 – 1.05 p.u.
- Voltage imbalance < 2% primary, 3% secondary
- If voltage is outside of range without DER, DER must not aggravate

Mitigation of Voltage Impacts using DER Reactive Power

- Reactive power injection and absorption may be considered as mitigation
- Constant power factor mode is preferred
- Closed-loop voltage regulation (volt-var) only if a specific study is performed to specify parameters and coordinate with LIPA system
- Reactive power consumption
  - Must be replaced elsewhere in the LIPA system – generators, transmission cap banks, or at the primary substation
  - May be subject to metered kVAR-hr charges

Distribution System Performance Standards (cont'd)

- Voltage variations
  - Flicker: P_{ST} and P_{LT} < 0.9; considering correlations
  - Rapid voltage change – depending on frequency of occurrence
  - LTC cycling: < 10% increase in operation count due to aggregation of DER – consider geospatial diversity
- Overvoltages – consistent with IEEE 1547-2018
- Harmonics – system must meet IEEE 519
- Short-circuit current contributions
  - Individual DER shall not consume more than 20% of available margin
  - Shall not cause nuisance lateral fuse operations
  - Shall not inhibit proper feeder protection

Distribution System Performance Standards (cont'd)

- Reclosing coordination
  - Instantaneous reclosing is used in LIPA system (~0.2 seconds)
  - On-board DER "anti-islanding" is insufficient to coordinate
  - Other means necessary if DER can support an island with significant voltage
    - Not an issue at low penetration on feeder <u>section</u>
    - Direct transfer trip (DTT) is usually necessary
    - Hot-line reclose blocking is not feasible at most LIPA substations
- Ground sources
  - Ground sources only to the degree necessary
  - Not needed/desired for inverter DER where feeder has majority of load L-N connected
  - Generally necessary for rotating generator DER

DER Interconnection Evaluation

Evaluations of Proposed DER Interconnections

- Evaluations consider:
  - Characteristics of the specific DER
  - Characteristics of the LIPA system at the PCC
  - Aggregate impact of all DER previously approved

Preliminary Screening

- Simple criteria to identify DER interconnection requests that have no significant risk of violating system performance criteria
  - Includes both individual and aggregate impacts

- Preliminary screening is exclusively for inverter DER
  - Rotating generator impacts do not fit with the screening

- If screening indicates "fail"
  - Request goes to supplemental screening in most cases
  - For some criteria, failure results in interconnection denial

Preliminary Screen P1

Screen P1 – Is interconnection to a secondary network or interconnection to a primary feeder that also supplies one or more secondary network proposed?

- Yes – Fail, interconnection to LIPA secondary networks is not permitted and if interconnection to a primary feeder serving a secondary network is proposed, a CESIR must be performed..
- No – Continue to Screen P2.

- DER interconnections can cause undesirable network protector operations
- Screen reflects longstanding LIPA system policy

Preliminary Screen P2

Screen P2 – Does the DER facility, including any of its transformers or generation equipment, present a ground source to the LIPA system having zero sequence admittance greater than 1.0 per unit on the bases of the LIPA system nominal voltage and the facility's rated kVA (the greater of the peak load kVA and the aggregate generation nameplate kVA rating).

- Yes – Fail, applicant can opt for a CESIR. Supplemental screening is not appropriate for failure of this screen.
- No – Continue to Screen P3.

- A study is essential to determine impact of ground source on protection

Preliminary Screen P3

Screen P3 – Does rated kVA of DER (and in the case of energy storage DER, does the maximum charging power plus the maximum load demand) exceed the rating of the secondary service cable or the service transformer?

- Yes – Fail, supplemental screening or CESIR are not appropriate for failure of this screen. The applicant may make arrangements for appropriate upgrade of service, and the screening process may then resume with Screen P4.
- No – Continue to Screen P4.

- Avoids overload of service
- Load that may not always be on cannot be considered as an offset

Preliminary Screen P4

Screen P4 – Is certified equipment to be used?

- Yes – Continue to Screen P5.
- No – Fail, applicant can opt for a CESIR. Supplemental screening is not appropriate for failure of this screen.

- Certified equipment assures IEEE 1547 compliance (for the most part) for DER that must be compliant at the DER terminals
  - Not absolute coverage; e.g., DER unit testing cannot assure that ANSI C84.1 voltage limits are not exceeded – system dependent
  - Large DER (exporting > 500 kW) must be compliant at PCC (utility meter point) which cannot be tested on a unit basis

Preliminary Screen P5

Screen P5– Does the DER penetration ratio, including the DER under review, of the distribution system served by a distribution substation bus exceed 80%?

- Yes – Fail, requester can opt for a CESIR. Supplemental screening is not appropriate for failure of this screen..
- No - Continue to Screen P6

- Provides a small margin to positively assure that there will not backfeed to the transmission system

Preliminary Screen P6

Screen P6 – Will the proposed interconnection use three-phase inverters or a reasonably balanced array of single-phase inverters?

- Yes – Continue to Screen P7
- No - Fail, applicant can opt for a CESIR. Supplemental screening is not appropriate for failure of this screen.

- Obviously applies only to three-phase DER interconnections
- Screen needed to avoid excessive circuit imbalance
- (Rarely an issue)

Preliminary Screen P7

Screen P7 – Is the interconnection to a primary lateral longer than 1000’ that also serves other customers?

- Yes – Fail, applicant can opt for a CESIR. The supplemental screening process does not accommodate long lateral situations.
- No - Applications for DER connected directly to a main feeder, a lateral shorter than 1000’, or via a dedicated lateral, can continue to Screen P8.

- Long laterals complicate analysis, this limitation is necessary to keep screening process simple
- If DER is on a dedicated lateral, no neighboring customers will be affected

Preliminary Screen P8

Screen P8 – Is the DER penetration ratio on any of the feeder sections described greater than 50%? (Note: this screen does not apply if direct transfer trip is otherwise required on the basis of DER rating.)

Feeder section to which the DER is connected.
The feeder starting from the substation to the next ASU beyond the point of DER connection, considering both normal and contingency feeder configurations.

- Yes – Fail, applicant can opt for supplemental screening. The supplemental screening process is to be entered at Screen S1.
- No, or DTT is otherwise required - Continue to Screen P9

- DER unlikely to sustain an island for the extent of a recloser cycle

Preliminary Screen P9

Screen P9 – Is the interconnection via a distribution transformer dedicated to the applicant's facility?

- Yes – Preliminary screening is successfully completed.
- No – Fail, applicant can opt for supplemental screening. The supplemental screening process is to be entered at Screen S13. Alternatively, the applicant may make arrangements for provision of dedicated transformer, and the preliminary screening process shall then be complete.

- If DER is on a dedicated service then secondary voltage variations do not affect other customers

Purpose of Supplemental Screening

- Alternative to going directly to a CESIR
  - Optional for interconnection applicant
- Requires system and DER data to evaluate, analysis without use of complex power system modeling tools
  - Based on simplified system calculations and empirical relationships
- Primarily for high-penetration situations
  - Enter supplemental screening at Screen S1
- Also addresses shared secondary situations
  - Enter supplemental screening at (last) Screen S13

Supplemental Screen S1

Screen S1 - Are there means to avoid out-of-phase reclosing, such as time-coordinated direct transfer trip or voltage-supervised reclosing?

- No – Fail, applicant may opt for a CESIR to determine if reclosing coordination is achieved.
- Yes – Continue to Screen S2.

- Time-coordinated transfer trip means DTT configured such that DER is off before feeder breaker opens
- Voltage-supervised reclose is not feasible in most LIPA substations because feeder side PTs are not readily installed in the switchgear

Supplemental Screen S2

Screen S2 – Can steady-state voltages on the primary feeder under normal conditions result in voltages at any other customer services greater than the upper limit of ANSI C84.1 Range A? (Refer to Appendix B-1 for the calculation on which this supplemental screen is based.)

- Yes – Fail, applicant may opt for a CESIR to provide a more refined analysis.
- No – Continue to Screen S3

- First screen (Test 2.1) is: $PR_{feeder} \leq 0.85$
- Remaining screens described on following slides

Test 2.2 – For Large PV DER

$$P_{new\_PV} + P_{ex} < MNDL \cdot \left[\begin{array}{l} \left(1.75 - 0.9 \cdot {d_{new}}/{d_{tot}}\right) \cdot \dfrac{P_{new\_PV}}{P_{new\_PV} + P_{ex}} + \\ \left(1.75 - 0.9 \cdot {d_{eq}}/{d_{tot}}\right) \cdot \dfrac{P_{ex}}{P_{new\_PV} + P_{ex}} \end{array} \right]$$

$$d_{eq} = \frac{\sum_n \left(P_n \cdot d_n\right)}{\sum_n P_n}$$

“Equivalent distance” of existing DER from substation

$$P_{effective} = P_{rated} \cdot \left(1 + 2.3 \cdot \frac{\sqrt{1 - pf^2}}{pf}\right)$$

Effective power” of DER, leading pf is a negative value

- Based on empirical analysis using typical feeder data

Test 2.3 – For Large Non-PV

$$P_{new\_non-PV} + P_{ex\_non-PV} < \frac{MNL}{P_{new\_non-PV} + P_{ex\_non-PV}} \cdot$$
$$\left[\left(1.75 - 0.9 \cdot {d_{new}}/{d_{tot}} \right) \cdot P_{new\_non-PV} + \left(1.75 - 0.9 \cdot {d_{eq\_non-PV}}/{d_{tot}} \right) \cdot P_{ex\_non-PV} \right]$$

$$P_{new\_non-PV} + P_{ex} < \frac{MNDL}{P_{new\_non-PV} + P_{ex}} \cdot$$
$$\left[\left(1.75 - 0.9 \cdot {d_{new}}/{d_{tot}} \right) \cdot P_{new\_non-PV} + \left(1.75 - 0.9 \cdot {d_{eq}}/{d_{tot}} \right) \cdot P_{ex} \right]$$

- Must meet both (daytime with PV and night without PV) constraint

Supplemental Screen S3

Screen S3 – Can steady-state voltages on the primary feeder under normal conditions result in voltages at any other customer services less than the lower limit of ANSI C84.1 Range A?

- Yes – Fail, applicant may opt for a CESIR to provide a more refined analysis.
- No – Continue to Screen S4.

- Concern is interaction of DER output with line-drop compensation of substation transformer OLTC
- Bus voltage may not be boosted enough to compensate for voltage drop on feeders without (as much) DER

Calculation for Screen S3

$$\frac{P_{DER\_tot} \cdot V_R}{\sqrt{3} \cdot V_{nom} \cdot CT} \cdot \left(1 - \frac{P_{DER\_\min} / P_{Ld\_\min}}{P_{DER\_tot} / P_{Ld\_tot}} \right) \leq 0.5$$

Where:

CT	=	Ratio of the CT used for OLTC control (CT:5, Amps)
P_{DER_min}	=	Total DER capacity on feeder with the least penetration (kW)
P_{DER_tot}	=	Total DER capacity on the substation bus (kW)
P_{Ld_min}	=	Peak load on the feeder with least penetration (kW)
P_{Ld_tot}	=	Peak load on the substation bus (kW)
V_{nom}	=	Nominal primary line-to-line voltage (kV)
V_R	=	Resistive setting of line drop compensation (Volts, 120 V base)

- Screen conservatively assumes that there is only 0.5 V margin left when feeder, lateral, transformer, and service cable voltage drops are considered

Supplemental Screen S4

Screen S4 – If the DER being screened is inherently variable in output, can the repetitive voltage variation due to the aggregate impact of all variable DER on the feeder exceed 2%?

- Yes – Fail, applicant may opt for a CESIR to make a more refined analysis.
- No, or the DER is not inherently variable – Continue to Screen S5.

- Does not apply to DER having relatively constant output
- Screening calculations are shown on following slides for PV
- Other types of variable DER will need a CESIR to evaluate voltage variability; e.g.:
  - Wind
  - Battery storage providing NYISO regulation service

Screen S-4 Calculations

- For a single PV DER > 25 kW on feeder: $$\frac{0.8 \cdot P_{PV} \cdot d_{PV} \cdot R_{fdr}}{V_{nom}^{2} \cdot 1000} \leq 0.02$$

- For a feeder with well-distributed PV DER (< 300 kW each unit) $$\frac{P_{Small\_PV} \cdot d_{tot} \cdot R_{fdr}}{V_{nom}^{2} \cdot 5000} \leq 0.02$$

- Where:

d_{PV}	=	Distance along feeder to PV under review (×1000')
d_{tot}	=	Total length of main feeder (×1000')
P_{PV}	=	Total DER capacity on the substation bus (kW)
R_{Fdr}	=	Resistance of main feeder per thousand feet (Ω/1000')
P_{Ld_tot}	=	Peak load on the substation bus (kW)
V_{nom}	=	Nominal primary line-to-line voltage (kV)

Screen S-4 Calculations – Multiple Large PV

1. Determine individual voltage variation contributions

$$\Delta V(n) = \frac{0.8 \cdot P(n) \cdot d(n) \cdot R_{fdr}}{V_{nom}^{2} \cdot 1000}$$

2. Determine which PV causes largest ΔV, location on main feeder where this facility is connected designated as the critical point

3. Screen for voltage variability at the critical point, considering geospatial correlation factor

$$\frac{0.8 \cdot R_{fdr}}{V_{nom}^{2} \cdot 1000} \cdot \left(\begin{array}{l} 0.25 \cdot P_{Small\_PV} \cdot d_{tot} + \\ \sum_{d(n)<d_{critical}} \left[P(n) \cdot d(n) \cdot k(n) \right] + d_{critical} \cdot \left(P_{critical} + \sum_{d(n)>d_{critical}} \left[P(n) \cdot k(n) \right] \right) \end{array} \right) \leq 0.02$$

Where:

$d_{critical}$	=	Critical distance (×1000’)
$d(n)$	=	Distance along feeder for PV facility n (×1000’)
$k(n)$	=	Geospatial correlation factor for facility n (unit-less)
$P(n)$	=	Capacity of PV facility n (kW)
$s(n)$	=	Straight-line distance to critical location (×1000’)

$$k(n) = \frac{0.9}{\sqrt[3]{s(n)}}$$

$$s(n) \approx \frac{\left| d(n) - d_{critical} \right|}{\sqrt{2}}$$

Supplemental Screen S5

Screen S5 – If the DER being screened is inherently variable in output, can the repetitive real and reactive current variations due to the aggregate impact of all variable DER on the distribution system served by the primary substation bus result in excessive operation of the primary substation's on-load tapchanger?

- Yes – Fail, applicant may opt for a CESIR to make a more refined analysis.
- No, or the DER is not inherently variable – Continue to Screen S6.

- Impact is via line-drop compensation interaction, not bus voltage variation
- Does not apply to DER having relatively constant output
- Screening calculations are shown on following slides for PV
- Other types of variable DER will need a CESIR to evaluate voltage variability

Screen S5 Calculation

$$\frac{k_{vrb} \cdot P_{vrb\_tot} \cdot V_R}{\sqrt{3} \cdot V_{nom} \cdot CT} \leq V_{db}$$

- Where:

  k_{vrb} = Variability factor – p.u. magnitude of power swing (unitless)

  P_{vrb_tot} = Total capacity of variable DER supplied by substation bus (kW)

  V_{db} = Deadband of substation transformer tap control (Volts, on 120 V base)

- Suggested variability factors:
  - PV: k_{vrb} = 0.8 (PV output when shadowed still is ~20% of the sunny output)
  - Battery storage providing NYISO regulation service: k_{vrb} = 2.0 (power swings both ways)

    (Note: NYISO does not presently have provisions for distributed resources to bid into the frequency regulation market)

Supplemental Screen S6

Screen S6 – Can simultaneous tripping of all DER on the distribution system result in any customer service voltages being less than the lower limit of ANSI C84.1 Range B?

- Yes – Fail, applicant may opt for a CESIR to make a more refined analysis.
- No – Continue to Screen S7.

- All DER on feeder may trip simultaneously for
  - Faults on same or other feeder
  - Transmission faults
- Substation transformer OLTC and capacitor status in the wrong position without DER supporting voltage
- Temporary condition until OLTC controls respond and capacitors are switched, thus ANSI C84.1 Range B applies

Screen S6 Calculation

$$\frac{P_{DER\_tot} \cdot V_R}{\sqrt{3} \cdot V_{nom} \cdot CT} \leq 4.0$$

- P_{DER_tot} is the total DER capacity on the substation bus (kW)
- With a 600:5 CT and V_R set to 3 V, this limits total DER to 18.3 MW per substation transformer

Supplemental Screen S7

Screen S7 – Can return to service of all DER on the distribution system result in any customer service voltages exceeding the upper limit of ANSI C84.1 Range B?

- Yes – Fail, applicant may opt for a CESIR to make a more refined analysis.
- No – Continue to Screen S8.

- Under IEEE 1547-2003, all DER could restart simultaneously following a mass trip event
- Substation transformer OLTC and capacitor status in the wrong position for DER operating
- Temporary condition until OLTC controls respond and capacitors are switched, thus ANSI C84.1 Range B applies
- IEEE 1547-2018 requires ramped restart, or randomly delayed restart for small DER; system controls should keep up with a gradual return

Screen S7 Calculation

$$\frac{P_{DER\_NoRamp} \cdot V_R}{\sqrt{3} \cdot V_{nom} \cdot CT} \leq 1.0$$

- P_{DER_NoRamp} is the total DER capacity having abrupt restart behavior, without randomized delay, on the substation bus (kW)
  - Assume all DER compliant to IEEE 1547-2003 has this characteristic
  - DER compliant with Cal Rule 21 (UL 1741SA) have programmable restart ramps
  - Future DER compliant with IEEE 1547-2018 will have either ramped restart or randomized restart delay for small DER (aggregate rating < 500 kVA)
- PSEG-LI will need to specify restart delays and ramp rates for new DER in the future
  - Make rate sufficiently slow so that OLTC can follow
- With a 600:5 CT and V_R set to 3 V, this limits total DER to 4.6 MW per substation transformer

Supplemental Screen S8

Screen S8 – Can the aggregate current injection by all DER on the distribution system result in fault currents exceeding the ratings of any LIPA equipment ?

- Yes – Fail, applicant may opt for a CESIR to make a more refined analysis.
- No – Continue to Screen S9.

- Inverter DER fault current contribution is ~110% - 120% of rating
  - Fault current contribution is largely independent of fault location
- Synchronous generator fault current contribution can be quite high:
  - 5x – 8x at DER terminals
  - 4x – 5x at MV level
  - Decreases with distance to fault
- Induction generator fault current is initially similar to synchronous generator, but decays over a few cycles

Screen S8 Calculation

$$\frac{2 \cdot S_{Inv\_total} + 6 \cdot S_{Rot\_total}}{\sqrt{3} \cdot V_{nom} \cdot 1000} + I_{no\_DER} \leq I_{momentary}$$

$$\frac{1.2 \cdot S_{Inv\_total} + 5 \cdot S_{Rot\_total}}{\sqrt{3} \cdot V_{nom} \cdot 1000} + I_{no\_DER} \leq I_{\text{int}erupting}$$

- Where:

S_{Inv_total} = Total inverter DER capacity connected to substation bus (kVA)

S_{Rot_total} = Total rotating generator DER capacity connected to substation bus (kVA)

I_{No_DER} = Available fault current without DER (kA)

$I_{momentary}$ = Momentary (close & latch) current rating for affected equipment (kA)

$I_{interrupting}$ = Interrupting current rating on load on the substation bus (kW)

Supplemental Screen S9

Screen S9 – Can the aggregate impact of all DER result in excessive load-rejection overvoltage?

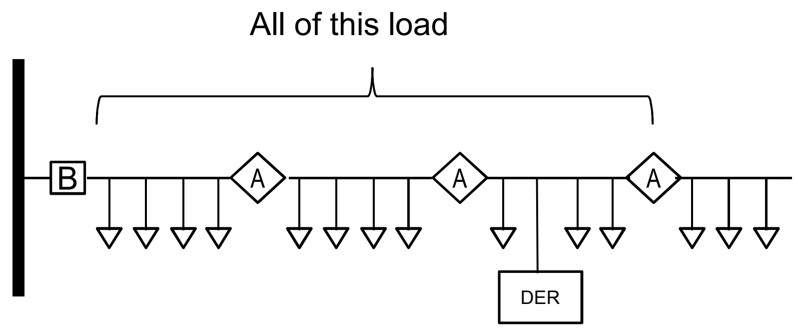
- Yes – Fail, applicant may opt for a CESIR to make a more refined analysis.
- No – Continue to Screen S10.

- Opening of feeder breaker while DER output exceeds load demand (backfeed) can result in an overvoltage
- Only applies to inverter-interfaced DER

Screen S9 Calculation

PV DER: $$\frac{DER_{sub-ASU}}{MDL_{sub-ASU}} \leq 1.4$$

Non-PV Inverter DER: $$\frac{NonPV_{sub-ASU}}{ML_{sub-ASU}} \leq 1.4$$



Where:

DER_{sub_ASU} = Total inverter DER capacity between substation and first downstream ASU

$NonPV_{sub\_ASU}$ = Non-PV inverter DER capacity between substation and first downstream ASU

MDL_{sub_ASU} = Minimum daytime load connected between substation and first downstream ASU

ML_{sub_ASU} = Minimum load (any time) connected between substation and first downstream ASU

The 1.4 p.u. criterion is a round-off of temporary overvoltage defining the limit of effective grounding ($0.8 \times \sqrt{3} = 1.386$)

Consider circuit reconfiguration

Supplemental Screen S10

Screen S10 – Can the aggregate impact of all DER result in excessive ground-fault overvoltage?

- Yes – Fail, applicant may opt for a CESIR to make a more refined analysis.
- No – Continue to Screen S11.

- Screening discriminates between inverter and rotating DER
- For inverter DER, L-N loads provide grounding
  - Key factor is the portion of loads that are L-N vs ungrounded
- For rotating DER, a large amount of load “swamps” the generator, resulting in no ground-fault overvoltage

Screen S10 Calculations for Inverter DER

PV DER + Non-PV Inverter DER : $$\frac{DER_{sub-ASU}}{MDL_{sub-ASU}} \leq 1.4 - 0.6 \cdot k_{\Delta}^{1.75}$$

Non-PV Inverter DER Only: $$\frac{NonPV_{sub-ASU}}{ML_{sub-ASU}} \leq 1.4 - 0.6 \cdot k_{\Delta}^{1.75}$$

- Where k_{Δ} is the fraction of load not connected phase-to-neutral (i.e., connected phase-to-phase, floating wye, or delta):

Screen S10 Calculations for Rotating DER

$$\frac{DER_{sub-ASU} + Rot_{sub-ASU}}{MDL_{sub-ASU}} \leq 0.26 - 0.1 \cdot k_{\Delta}$$

and

$$\frac{NonPV_{sub-ASU} + Rot_{sub-ASU}}{ML_{sub-ASU}} \leq 0.26 - 0.1 \cdot k_{\Delta}$$

- Where:
  - Rot_{sub_ASU} = Total inverter rotating generator DER capacity between substation and first downstream ASU
- Both screens need to be passed ("and")
- Both induction and synchronous generators are "rotating" as used here
- All DER capacity is conservatively assumed to be rotating generator in these screens

Supplemental Screen S11

Screen S11 – Is the interconnection potentially disruptive to protection coordination?

Yes – Fail, applicant may opt for a CESIR to make a more refined analysis or to determine necessary system protection modifications.
No – Continue to Screen S12.

- Screen based on DER short-circuit contribution (3-ph) relative to short-circuit level at primary PCC
  - Assumes all DER contributions are located at the evaluated PCC
- Additional screen to ensure zero-sequence contribution of all ground-sourcing DER < 100 A

Screen S11 Calculations

Positive/negative sequence test:

$$\frac{1.2 \cdot \Sigma S_{Inv} + 5 \cdot \Sigma S_{Rot}}{\sqrt{3} \cdot V_{nom} \cdot 1000} \leq 0.1 \cdot I_{SC}$$

Zero sequence test*:

$$\frac{V_{nom} \cdot 1000}{\sqrt{3}} \cdot \sum_{n} \frac{1}{Z_0(n)} \leq 100$$

- Where:

ΣS_{Inv} = Total inverter DER capacity connected to feeder (kVA)

ΣS_{Rot} = Total rotating generator DER capacity connected to feeder (kVA)

I_{SC} = Minimum three-phase fault current level at primary near PCC (kA)

$Z_0(n)$ = Minimum Zero-sequence impedance of ground source n connected to feeder. (Sum all such ground source admittances on feeder)

- *Zero sequence test applies only to DER providing a ground source

Supplemental Screen S12

Screen S12 – Is the interconnection via a distribution transformer dedicated to the applicant's facility?

- Yes – Supplemental screening is successfully completed.
- No – Continue to Screen S13.

- With a dedicated transformer, there is not a need to consider secondary system impacts

Supplemental Screen S13

Screen S13 – Is the location of the service transformer on the feeder such that the service voltage provided to other customers sharing the same distribution transformer are less than the upper limit of ANSI C84.1 Range A?

- Yes – Supplemental screening is successfully completed.
- No – Fail, applicant may arrange for a dedicated transformer or may opt for a CESIR to make a more refined analysis.

- For services near the head of the feeder, primary voltage may be so high as to not allow any rise across distribution transformer

Screen S13 Calculation

$$P_{effective} \leq 0.1 \cdot S_{xfmr} \cdot d \cdot \left(1 - PR_{feeder}\right)$$

- Where:

$P_{Effective}$	= Effective rating of DER, considering pf (kW)
S_{Xfmr}	= Rating of distribution transformer (kVA)
d	= Distance along main feeder where service transformer (or lateral) is connected (×1000')
PR_{feeder}	= DER penetration ratio of feeder (unitless)

- This screen is based on the following assumptions:
  - Voltage rise through distribution transformer for rated reverse flow at 1.0 pf = 2%
  - Voltage drop along main feeder is 0.2%/kft at light daytime load

Coordinated Electric System Interconnection Review

- Interconnection screens are not intended to be the final criteria for interconnection
- Applicant can opt for a detailed engineering study (CESIR) that evaluates expected performance with respect to the system performance criteria (Section 3)
- Scopes of CESIR are defined on a case-by-case basis depending on:
  - Characteristics and rating of DER systems
  - Characteristics of LIPA system at the proposed point of interconnection
  - Specific criteria failed in the screening process
- Coverage of CESIR in the document is presently a limited placeholder

Interconnection Design Requirements

Design Requirements

- Interconnection document only specifies requirements that are in addition to, modify, or further define those specified in IEEE 1547
  - IEEE 1547-2018 was the basis
  - Presently in an interim state where test standards have not caught up to the performance standard

Reactive Power Capability and Control

- Reactive power and control capability as specified in IEEE 1547-2018
  - Rotating generators shall comply with Category A requirements
  - Inverter-interfaced DER shall comply with Category B requirements
- Default is unity power factor operation
- Any control modes specified in IEEE 1547 may be required to be implemented at any time
  - Modes and parameters to be specified by PSEG-Long Island
- Reactive power flow is subject to tariff

Disturbance Performance

Ride-through capability as specified in IEEE 1547-2018

- Synchronous and induction generators – Category I
- Inverter-interfaced DER – Category II

Voltage tripping

Voltage Range (% of base voltage)	Clearing Time (seconds)	Clearing Time (cycles)
V ≥ 120	0.16	9.6
V ≥ 110	1.0	60
V ≤ 88	5.0	300
V ≤ 50	0.16	9.6

Frequency tripping

Frequency Range Hz	Clearing Time (seconds)	Clearing Time (cycles)
f ≥ 61.0	180	10800
f ≥ 62.0	0.16	9.6
f ≤ 58.0*	180	10800
f ≤ 56.5*	0.16	9.6

Re-entry to service after trip – 5 minute delay after voltage between 0.9 – 1.05 p.u. and frequency between 59.3 and 60.5 Hz

Protection Requirements (> 500 kVA) for Inverter DER

- Utility-grade relays are required in addition to protections integrated into inverter per IEEE 1547/UL1741
  - Under/over voltage (59/27)
  - Over/under frequency (81O/U)
  - Sync check (25) – only for "grid forming inverters"
  - Phase and ground overcurrent (50P/51P/50N/51N)
  - Transformer differential (87T) – only for banks > 2000 kVA
  - Negative sequence overcurrent or overvoltage (depends on inverter)
  - Zero sequence overvoltage – 3V0 (59G)
  - Directional power (32) – as required for contractual limitations

Protection Requirements (> 500 kVA) for Synch Gen DER

- Required utility-grade relay functions:
  - Sync check (25)
  - Under/over voltage (59/27)
  - Over/under frequency (81O/U)
  - Voltage restrained instantaneous/time overcurrent (50/51V)
  - Negative sequence overcurrent
  - Phase and ground overcurrent (50P/51P/50N/51N)
  - Bus differential (87B)
  - Transformer differential (87T) – only for banks > 2000 kVA
  - Loss of excitation (40)
  - Generator differential (87G)
  - Directional power (32) – as required for contractual limitations

Protection Requirements (> 500 kVA) Induction Gens

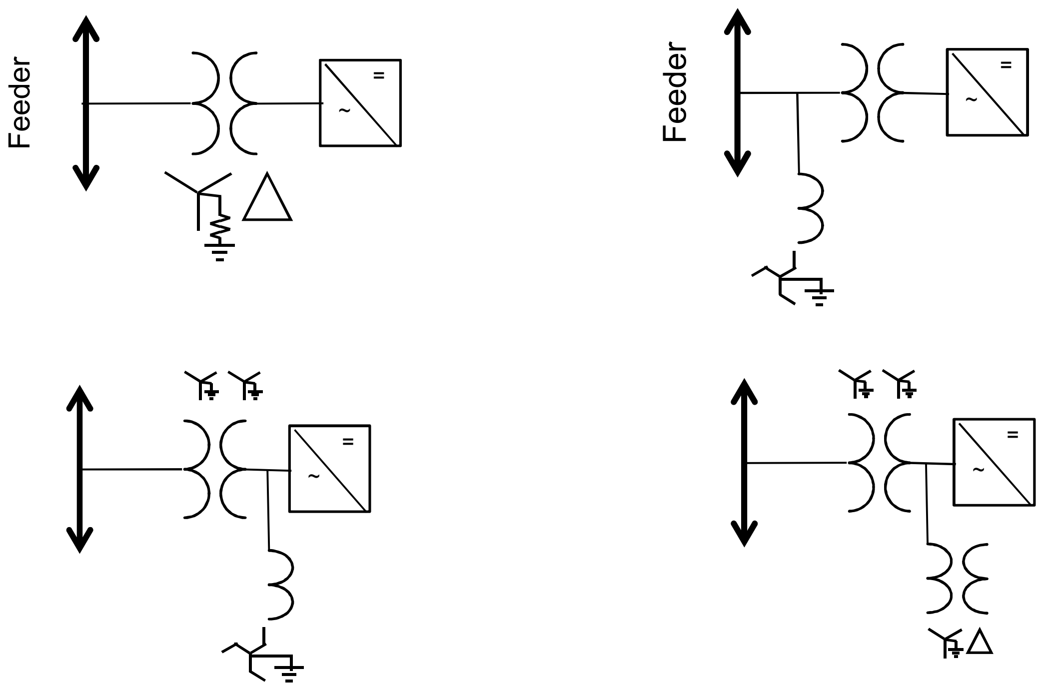
- Required utility-grade relay functions:
  - Under/over voltage (59/27)
  - Over/under frequency (81O/U)
  - Phase and ground overcurrent (50P/51P/50N/51N)
  - Bus differential (87B)
  - Transformer differential (87T) – only for banks > 2000 kVA

Reclosing Coordination

- If DER penetration on feeder is sufficient to maintain > 0.2 p.u. voltage while islanded, all additional DER must avoid islanding for longer than “instantaneous” reclose time (~12 cycles)
- DER anti-islanding functionality required by IEEE 1547/UL1741 not deemed sufficient
- Alternatives:
  - Direct transfer trip (DTT) - time coordination can be a challenge
  - Hot line blocking (a.k.a., undervoltage permissive) of reclose – physical constraints to adding PTs to feeder side of substation breaker
- DTT required on all DER ≥ 1000 kVA

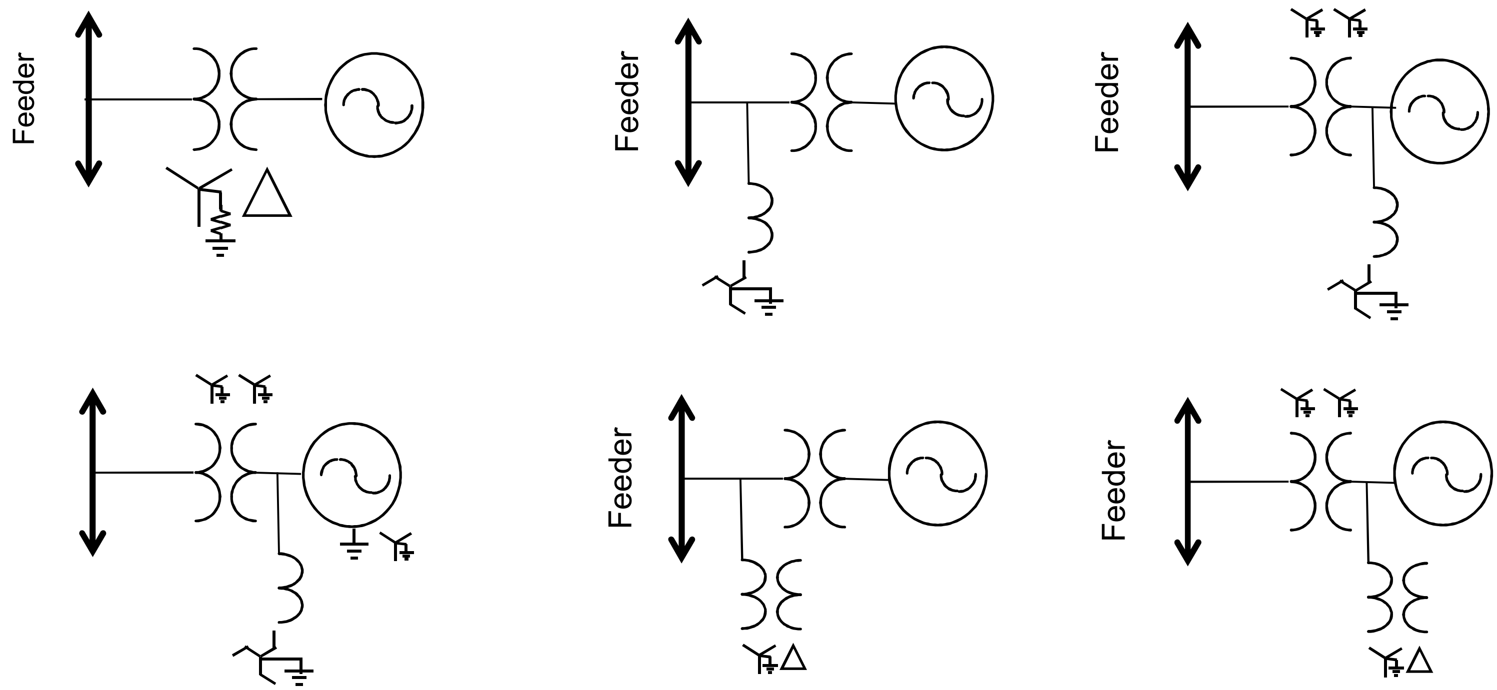
Transformer Configurations (>500 kVA) for Inverter DER

- Yg-yg preferred unless CESIR shows need for ground source
- Where ground sources are required:



Transformer Configurations (>500 kVA) for Rotating Gen

- Rotating generators > 500 kVA required to provide a ground source



SCADA

- DER ≥ 1000 kVA must have SCADA interconnection
- RTU must use DNP 3.0 serial protocol
- DER owner must provide for comms lines:
  - Dedicated leased TLS communication circuit
  - Backup via 4G
- Monitoring and control information:
  - Phase voltages and currents
  - Active and reactive power (P & Q)
  - Breaker status
  - DTT comm alarms
- Additional requirements for energy storage:
  - Available/unavailable status
  - Start/stop control
  - Automatic charge/discharge control mode
  - Active and reactive power dispatch

Engineering Studies (>500 kVA)

- Studies to be performed by, or on behalf of DER owner
  - Relay coordination
  - Grounding
    - Demonstrate effective grounding
    - Size neutral impedance to limit ground current at substation to 400 A (aggregate impact of all DER ground sources)

Design Documentation

- Information required in application forms
- Detailed one-line drawing
- Instruction manual (for inverters)
- Additional for DER > 500 kVA:
  - Relay functional diagram (on one-line)
  - Three-line ac diagram
  - DC schematics
  - Transformer rating and impedances
  - DC power supply documentation
  - Interconnection breaker speed curve
  - Battery spec sheet and maintenance procedures
  - Fuse data
  - CT data
  - Relay settings files and summary sheet
  - Protection functional test plan
  - Relay test reports

Commissioning and Testing

Inverter DER < 25 kVA

- Commissioning test: interrupt LIPA source
  - Verify deenergization
  - Verify five-minute delay for return to service after source is restored
- Repeat every four years (at PSEG-LI discretion)

DER $\geq$ 25 kVA

- Verification test procedure must be defined
- Pre-interconnection testing must be performed by qualified testing company
  - Verification tests performed prior to parallel operation
  - Repeated for any hardware or software changes
- Recurring tests on a 6 year cycle

DER Operations

PSEG LONG ISLAND
We make things work for you.

DER Operations

- Maintain compliance with IEEE 1547 version applicable at commissioning
- PSEG-Long Island to prepare and deliver Operating Instructions
- DER owner maintains point of contact
- Modifications to DER system requires PSEG-Long Island approval
- No backfeed during LIPA outage
- Grounds for DER disconnection are specified

Questions?

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