Intermittent Renewable Resources (IRR)
Transmission Interconnection Code (TIC)

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IRR-TIC 1. Introduction

All Generators connecting to the Transmission System must comply with the National Electrical Power Company (NEPCO) grid code (Grid Code). However the Grid Code was originally developed assuming synchronous generators. Wind Farm (WF) generators and Photovoltaic (PV) generators, collectively in the category of Intermittent Renewable Resources (IRR)s, merit provisions of the Grid Code specifically for them which are provided in this document named IRR-TIC.

Although the grid code provided in this document was written with WF and PV generators in mind, it also may be extended to all IRRs.

IRR-TIC 2. Scope

The primary objective of this document is to establish the technical rules which IRRs must comply with in relation to their connection to and operation on the Transmission Network.

IRR-TIC applies to IRRs that are connected to the Transmission Network, where the Transmission Network is as defined in the Grid Code; this includes IRRs directly at NEPCO's 33 kV bus bar. This Code is applicable to projects **[NEPCO TO DEFINE THE CRITERIA SUCH AS A CUT-OFF DATE, OR SIGNED INTERCONNECTION AGREEMENT, OR OTHER CRITERIA].**

In addition to compliance with IRR-TIC, IRRs are required to comply with the Grid Code, including in particular the following sections of the Grid Code:

- GC - General Conditions
- PC - Planning Code
- PC Appendix A excluding
  - PCA 1.3.3
  - PCA 2.3
- CC- Connection Conditions excluding:
  - CC 5.2.3

IRRs shall also comply with the following:

- OC – Operating Code excluding
  - OC 3.6.2
  - OC 10.7.5
- SDC – Scheduling and Dispatch Code
- MC – Metering Code

Where the IRR-TIC may conflict with the Grid Code, the IRR-TIC shall override. Language in the Interconnection Agreement & other Agreements (such as Power Purchase Agreement) for an IRR with NEPCO shall override both IRR-TIC and the Grid Code. "IRR" is interchangeable with "Generating Unit" and "Plant" in the Grid Code.

IRR-TIC 3. Definitions and Acronyms

Where otherwise not defined here, definitions are as provided in the Grid Code.

Active Power: The product of voltage and the in-phase component of alternating current (normally measured in kilowatts (kW) or megawatts (MW)).

Active Power Control: The automatic change in Active Power output from IRR in a response to an Active Power Control Set-Point received from NEPCO.

Active-Power Control Set-point: The maximum amount of Active Power in MW, set by NEPCO, which the IRR is permitted to export.

Available Active Power: The amount of Active Power that the IRR could produce based on current resource conditions. Generally for an IRR the Available Active Power is the same as the Active Power, unless the IRR has been curtailed, constrained or is operating in a restrictive Frequency Response mode.

Grid Code: NEPCO Transmission Grid Code, First Amendment Version, February 2010

Frequency Response: Is the automatic decrease or increase in active power output of an IRR in response to a system frequency rise or fall, in accordance with primary control capability

HV: High voltage, typically higher than 33 kV, however in the context of generator interconnection in the IRR-TIC it also includes NEPCO's 33 kV bus-bar.

HVRT: High voltage ride-through

IRR: Intermittent Renewable Resource, A Generation Resource that can only produce energy from variable, uncontrollable resources, such as wind or solar

IRR Unit: One inverter block (for PC) or one turbine (for wind) along with its transformer, which is the basic unit generator in an IRR plant which may include several of such units in a collection system configuration.

IRR-TIC: Intermittent Renewable Resource – Transmission Interconnection Code, as presented in this document in whole or in part

LVRT: Low voltage ride-through

MV: Medium Voltage, 1 kV up to 33 KV

NEPCO: National Electric Power Company of The Hashemite Kingdom of Jordan

PCC: Point of Common Coupling located on the HV substation side of the IRR that connects to NEPCO's facilities. It can reach up to the incoming cable sealing ends.

PFR: Primary Frequency Response. The instantaneous proportional increase or decrease in real power output provided by a generation resource and the natural real power dampening response provided by load in response to system frequency deviations. This response is in the direction that stabilizes frequency

PV: Photovoltaic generating plant consisting of several inverters as collection systems connected to the point of common coupling via a solar farm collector grid

Reactive Power: The product of voltage and the out-of-phase component of alternating current (normally measured in kilovars (kVAr) or megavars (MVAr)). Reactive Power is produced by capacitors, overexcited generators and other capacitive devices and is absorbed by reactors, under-excited generators and other inductive devices.

SSR: Sub-synchronous Resonance

SSI: Sub-synchronous Interference

Transmission System: Used interchangeably with Transmission Network, where the latter is defined in the Grid Code

WF: Wind farm generating plant consisting of several wind turbines connected to the point of common coupling via a wind farm collector grid

Generator active/reactive power sign/direction conventions:

Active power output from a generator is positive (+) flow.

Lagging power factor operating condition is when reactive power flow is out of the Generation Resource (overexcited generator) and is considered to be positive (+) flow, i.e., in the same direction as active power flow. The generator is producing reactive power (capacitive).

Leading power factor operating condition is when reactive power flow is into the Generation Resource (under-excited generator) and is considered to be negative (-) flow, i.e., in the opposite direction to active power flow. The generator is absorbing reactive power (inductive).

Unity power factor operating condition is when no reactive power is flowing from or out of the Generation Resource (normally excited generator).

IRR-TIC 4. Frequency Requirements

IRR-TIC 4.1. Relaying Requirements

Under extreme system fault conditions all IRR units must be disconnected at a frequency greater than 51.5 Hz. At a frequency less than 47 Hz they may be disconnected at generator discretion. Where under and over frequency relays are installed, these relays shall be set such that the automatic removal of the IRR from NEPCO's Transmission Network meets the requirements shown in Table 4-1.

Table 4-1 - Frequency Relaying Requirements

Frequency Range	Delay to Trip
51.5 Hz < Freq	.5s
47.5 Hz ≤ Freq ≤ 51.5 Hz	**Continuous Operation**
47.0 Hz < Freq < 47.5 Hz	20s
Freq = 47.0 Hz	.5s

Additionally:

- IRRs must remain connected to the Transmission System during rate of change of Transmission System Frequency of values at least up to and including 0.5 Hz per second
- No additional IRR shall be started while the Transmission System Frequency is above 50.2 Hz.
- The operational characteristics of the relay operation must be coordinated with other control systems of the IRR (such as excitation, frequency (speed) governor response, and other controls where applicable).

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IRR-TIC 4.2. Active Power Requirements

IRR plants shall be capable of operating at reduced power output after receiving a signal from the Transmission System operator. The following should be implemented, but not activated. It has to be activated on request of the Transmission System operator anytime.

The generating plants must be capable of reducing their active power in steps amounting to a maximum 10% of the registered capacity (generally being the same as the rated nameplate capacity) at the PCC. This power reduction must be possible in any operating condition and from any operating point to a target value given by the Transmission Network operator. This target value is normally preset without steps or in steps, and corresponds to a percentage of the nameplate capacity.
The reduction of the power output to the respective target value must be realized without delay, but within one minute, at the latest, from receiving the signal from the Transmission Network operator.
The Transmission Network operator shall not interfere in the control of the IRR; it shall only be responsible for signaling.

IRR-TIC 4.3. Governor – Primary Frequency Response (PFR)

IRRs that have capacity available to either increase output or decrease output in real-time must provide PFR, which may make use of that available capacity response to Transmission System frequency deviations. The PFR shall be similar to the droop characteristic governor system used by conventional steam generators. The governor droop shall be set by NEPCO and be in the range of 2% to 10%, with a default of 5%. The generation resource automatic control system design shall have an adjustable dead band that defaults at +/- 0.03 Hz.

In Primary Frequency Response mode the PFR control system shall have the capabilities as displayed in the Power-Frequency Response Curve in Figure 4-1, where the power and frequency ranges required for points A, B, C, D, E shall be defined by NEPCO. The default requirements are for A and B to be at 100%, where the code does not currently require IRRs to operate below the active operating power available to them from the resource, unless the IRR was in a state of curtailment at the time of frequency deviation below 49.5 Hz.

All IRRs in operation must reduce their instantaneous active power output when the system frequency is more than 50.5 Hz as shown in Figure 4-1. The default droop of 5% means 100% change in power output for 5% frequency deviation, which also translates to decreasing output at a gradient of 40% of the generators instantaneously available capacity per Hz as illustrated in Figure 4-2 .

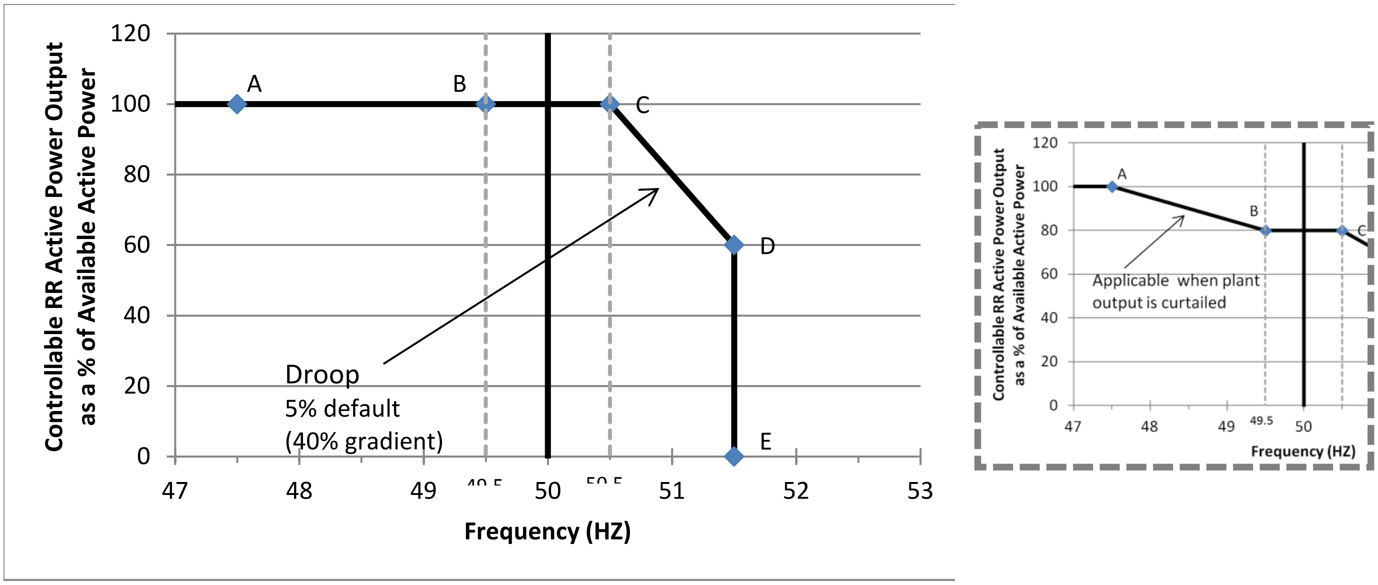
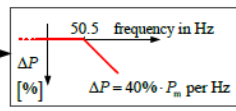


Figure 4-1 - Power-Frequency Response Curve

$f_{\text{grid}} \longrightarrow$  $\longrightarrow \Delta P$

$$\Delta P = 20 P_{\text{m}} \frac{50.5 \text{ Hz} - f_{\text{grid}}}{50 \text{ Hz}} \quad \text{at } 50.5 \text{ Hz} < f_{\text{grid}} < 51.5 \text{ Hz}$$

P_{m} instantaneously available power

ΔP power reduction

f_{grid} grid frequency

For $47.5 \text{ Hz} < f_{\text{grid}} \le 50.5 \text{ Hz}$ continues operation

At $f_{\text{grid}} \le 47.5 \text{ Hz}$ and $f_{\text{grid}} \ge 51.5 \text{ Hz}$ disconnection from grid

Figure 4-2 – <u>Default droop of 5% -</u> Active power reduction at around 50.5 Hz grid frequency with a gradient of 40%

Controllable IRR Frequency Response and Governor Droop shall be calculated with respect to the IRR registered capacity (generally being the same as the rated nameplate capacity). A controllable IRR can provide low frequency support only if the Active Power Control set-point is less than the Available Active Power. The code however does not currently require IRRs to operate below the active operating power available to them from the resource, unless the IRR was in a state of curtailment at the time of frequency deviation below 49.5 Hz.

Under normal Transmission System Frequency ranges, the IRR shall operate with an Active Power output as set by the line ‘B’ - ‘C’. If the Transmission System Frequency falls below point ‘B’, then the Frequency Response System shall act to ramp up the IRR’s Active Power output, in accordance with the Frequency/Active Power characteristic defined by the line ‘B’-‘A’. The code however does not currently require IRRs to operate below the active operating power available to them from the resource, unless the IRR was in a state of curtailment at the time of frequency deviation below 49.5 Hz.

Where the Transmission System Frequency is below the normal range and is recovering back towards the normal range, the Frequency Response system shall act to ramp down the IRR’s Active Power output in accordance with the Frequency/Active Power characteristic defined by the line ‘A’-‘B’.

Frequency dead-band shall be applied between the Transmission System Frequencies corresponding to points ‘B’ and ‘C’, where no change in the IRR’s Active Power output shall be required.

Once the Transmission System Frequency rises to a level above point ’C’, the Frequency Response System shall act to ramp down the IRR’s Active Power output in accordance with the Frequency/Active Power characteristic defined by the line ‘C’-‘D’-‘E’. At Transmission System Frequencies greater than or equal to ‘D’-‘E’, there shall be no Active Power output from the IRR.

Points ‘A’, ‘B’, ‘C’, ‘D’ and ‘E’ shall depend on a combination of the Transmission System Frequency, Active Power and Active Power Control Set-point settings. These settings may be different for each IRR depending on system conditions and IRR location, and shall be defined by NEPCO.

Alterations to the Active Power Control Set-point may be requested in real-time by NEPCO and the implementation of the set-point shall commence within 10 seconds of receipt of the signal from NEPCO. The rate of change of output to achieve the Active Power Control Set-point should be no less than the maximum ramp rate settings of the IRR control system.

Alterations to the Active Power output, triggered by Transmission System Frequency changes, shall be achieved by proportionately altering the Active Power output of all available IRR units as opposed to switching individual units on or off, where possible.

No time delay other than those necessarily inherent in the design of the Frequency Response System shall be introduced. The Frequency Response System shall continuously monitor the Transmission System Frequency in order to continuously determine the IRR’s appropriate Active Power output.

If the Transmission System Frequency rises to a level above ‘D’-’E’, as defined by the Power-Frequency Response Curve in Figure 4-1, the IRRs will not be required to provide frequency response service and may disconnect in accordance with the time delays set in Table 4-1. Any IRR which has disconnected shall be brought back on load as fast as technically feasible (provided the Transmission System Frequency has fallen below 50.5 Hz).

Procedure for Setting and Changing the Power-Frequency Response Curves: Two Power-Frequency Response Curves (Curve 1 and Curve 2) may be specified by NEPCO at least 120 Business Days prior to the IRR’s scheduled Operational Date. The IRR shall be responsible for implementing the appropriate settings during Commissioning. The Frequency Response System shall be required to change between the two curves within one minute from receipt of the appropriate signal from NEPCO.

IRR-TIC 5. Voltage Requirements

IRR-TIC 5.1. Voltage Range & Relaying Requirements

IRRs shall remain continuously connected to the Transmission Network at maximum Available Active Power or Controlled Active Power output for normal and disturbed system conditions for step changes in Transmission System voltage of up to 10 % as shown in Table 5-1

Table 5-1 - Voltage Relaying Requirements

Voltage Range (% $V_{nominal}$)	Delay to Trip
$115 \leq V < 120$	.2s
$110 < V < 115$	1s minimum*
$90 \leq V \leq 110$	Continuous Operation
$85 \leq V < 90$	60s minimum*
$80 \leq V < 85$	10s
$0 < V < 80$	0.3s to 2.5s per LVRT graph
$V = 0$	.3 s

*Equipment capable of staying on-line for longer duration must activate that capability in coordination with NEPCO

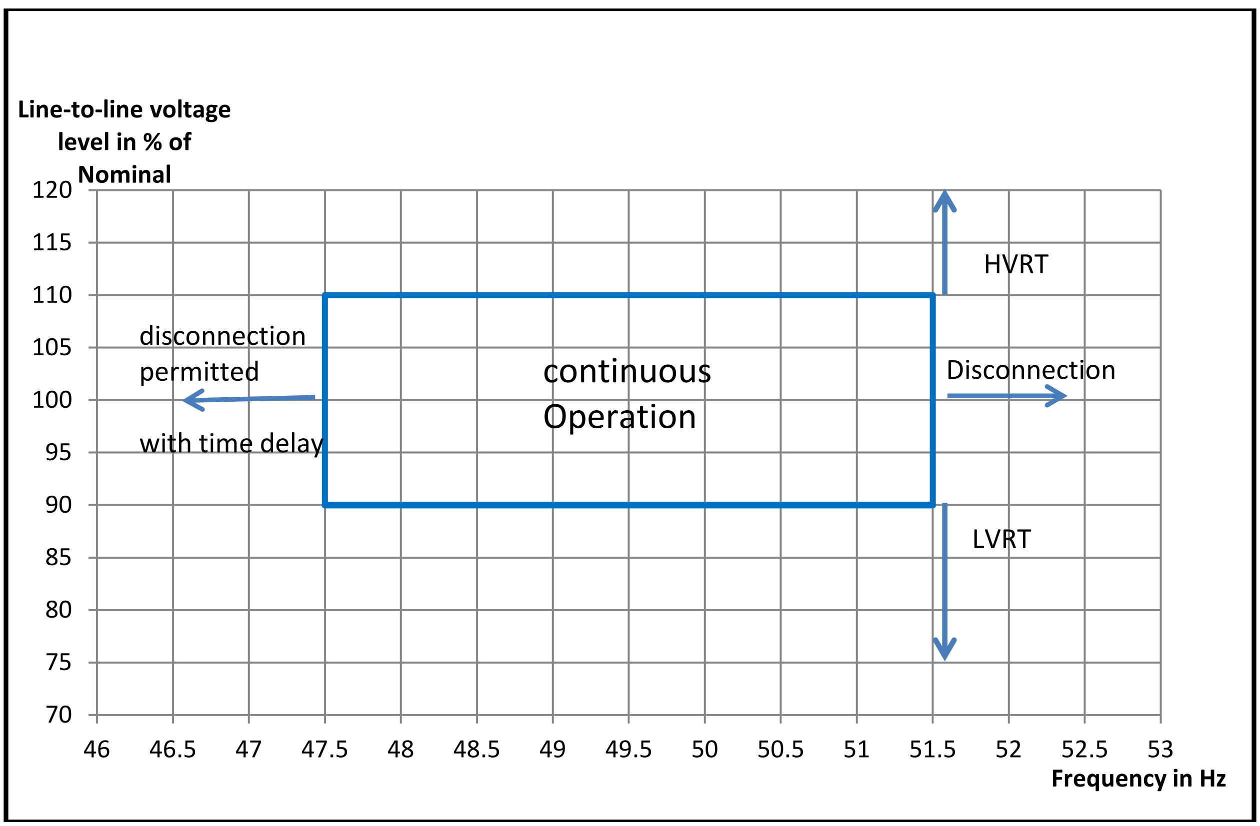


Figure 5-1 - Required Duration of Operation of an IRR in Dependency to the PCC Voltage and the Nominal Frequency

IRR-TIC 5.2. Fault Ride Through (Zero and LVRT)

The Low Voltage Ride-Through (LVRT) specifies the capability range for IRRs to remain connected to the system during and following grid faults, including the requirement to participate in the dynamic voltage control. The dynamic voltage control, to be superimposed on the steady state voltage control, is to be implemented as a fast local control to change the reactive current output of the IRR as necessary to counter the sudden voltage change resulting from grid faults and disturbances.

A voltage fall below the red line triggers the permitted disconnection of the unit. IRR must be capable of remaining connected at or above this limit during and immediately after any short circuit which is correctly isolated by protection schemes even in the case of action by the second level protection. IRR must survive a zero voltage dip of at least the depth shown in the solid red line at the PCC in Figure 5-2.

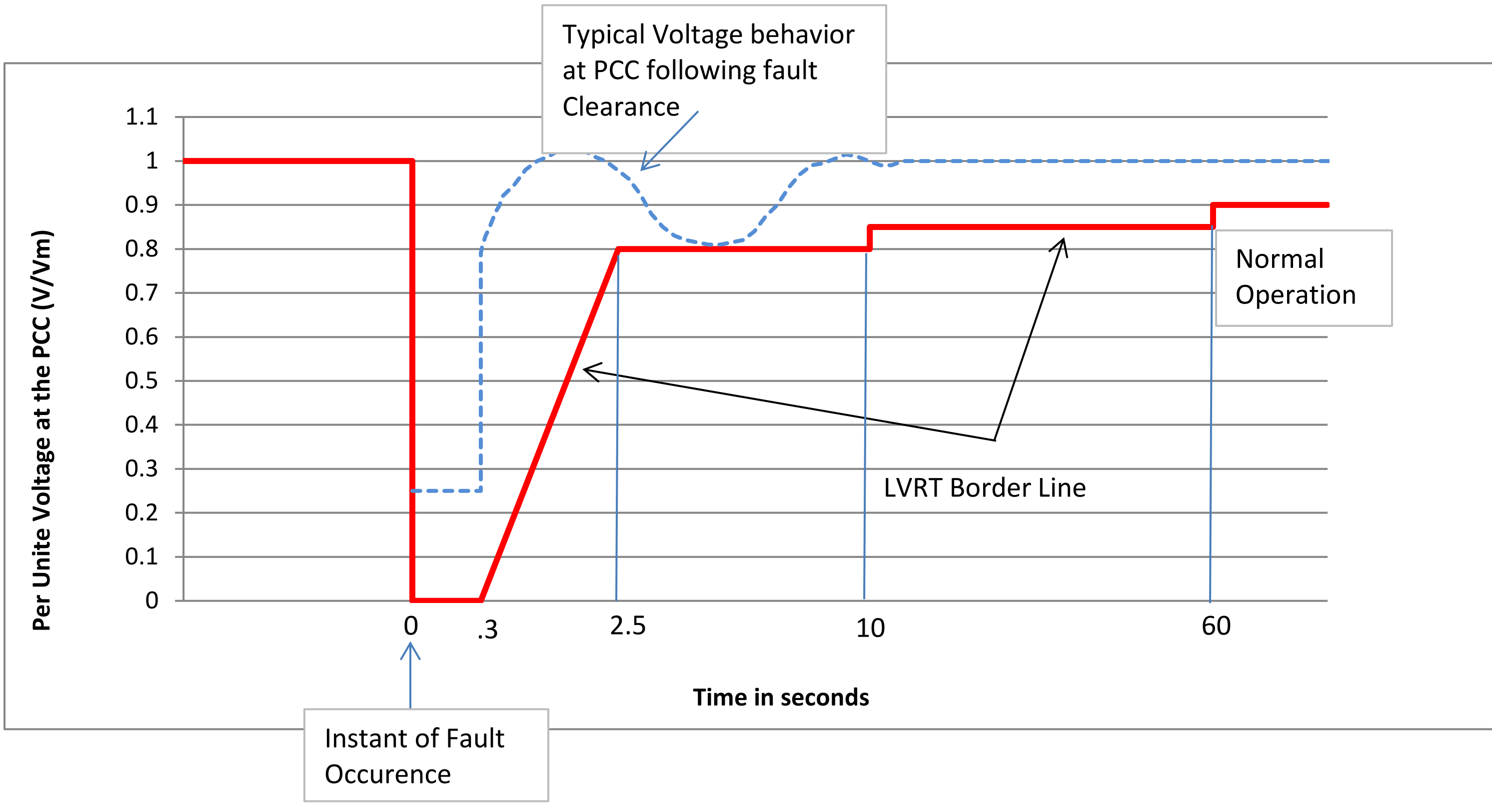


Figure 5-2 - Definition of Voltage Characteristic at the PCC for LVRT

During the Transmission System Voltage dip the IRR shall provide Active Power in proportion to retained voltage and maximize reactive current to the Transmission System without exceeding IRR Unit generator limits. The maximization of reactive current shall continue for at least 300 ms or until the Transmission System Voltage recovers to within the normal operational range of the Transmission Network, whichever is the sooner. IRRs must survive any incident of this severity in the voltage dip and duration.

The IRR shall recover, at the minimum, 90% of their generation prior to the incident, but as available from the natural resources, as quickly as the technology allows, but within no more than one minute after the voltage has recovered to its normal operating range.

IRR-TIC 5.3. High Voltage Ride Through (HVRT)

The curves in **Figure 5-3** refer to the positive sequence voltage at the fundamental frequency.

Exceeding the solid border line triggers the immediate disconnection of the unit. IRRs must be capable of remaining connected at or below this limit during and immediately after any system condition. Any other disturbances as well should not result in the border line shown in **Figure 5-3** being crossed. These are minimum requirements, however NEPCO requires equipment that is capable of riding through higher voltage and longer duration to deploy their full capability in coordination with NEPCO.

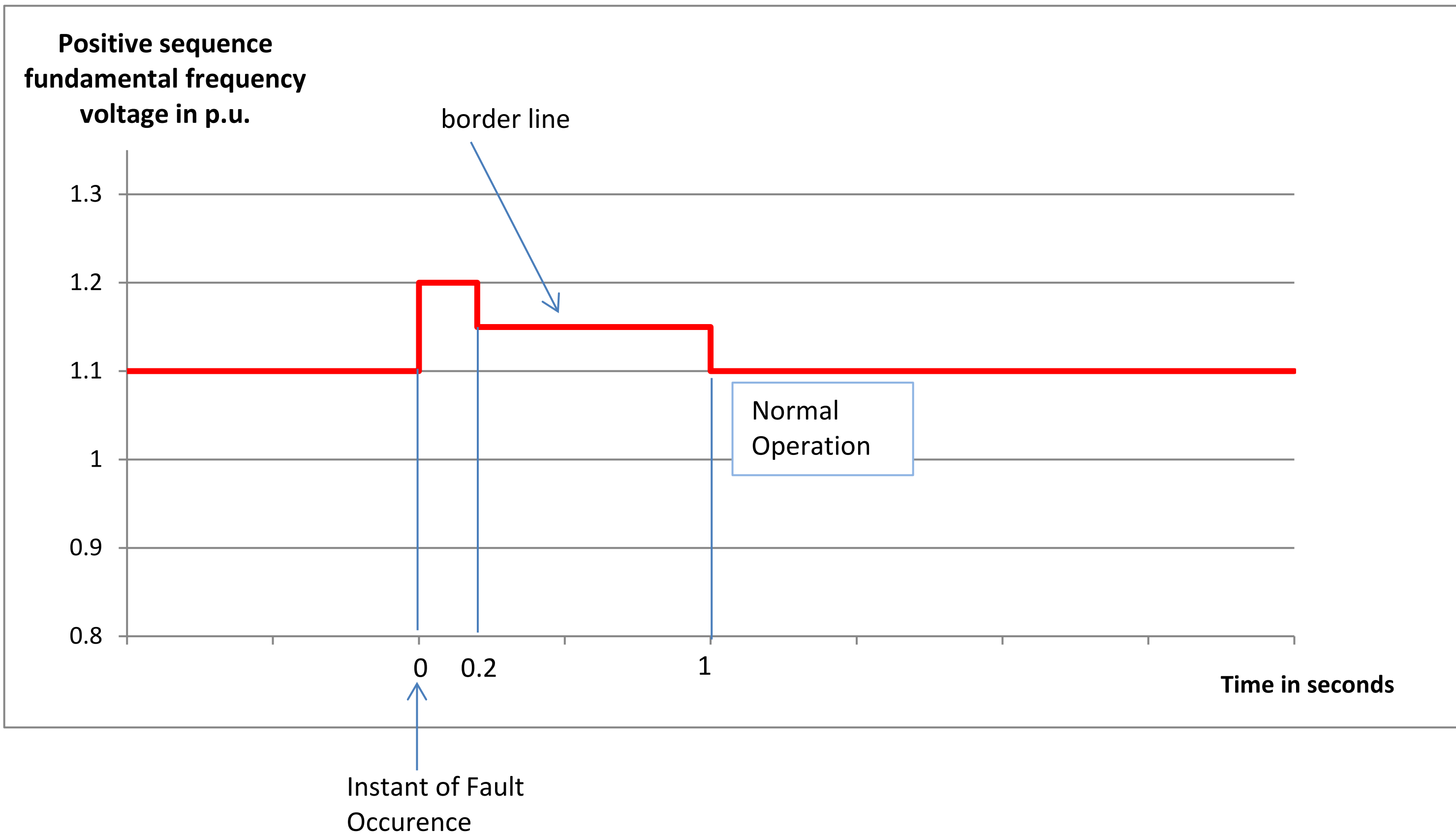


Figure 5-3 - Definition of Voltage Characteristic at the PCC for HVRT

IRR-TIC 5.4. Automatic Voltage Regulation (AVR)

IRR must be capable of operating in a voltage control mode to maintain the voltage at the PCC to stay at a set point provided by the DISCO to the IRR. The voltage setting requirement shall be within the normal operating range of the system (+/- 10% of nominal)

IRR must respond to a sudden voltage decrease/increase with the corresponding fast positive sequence fundamental frequency reactive current output in accordance with Figure 5-4. The requirements refer to the PCC. It is recommended to implement fast voltage controller functionality at the IRR level corresponding to the requirements below. However, to fulfill these requirements at the PCC, under certain circumstances, higher requirements must be implemented at IRR level as indicated in Figure 5-4. It is at the discretion of the IRR whether only IRR units or other Var equipment like STATCOM close to the PCC are installed for Var generation and fast voltage control of dynamic nature.

Figure 5-4 illustrates an example of required static gain of the voltage controller. A controller with higher dynamic gain (e.g. by implementing proportional-differential controller characteristic) is acceptable as long as the stability of the voltage controller is guaranteed.

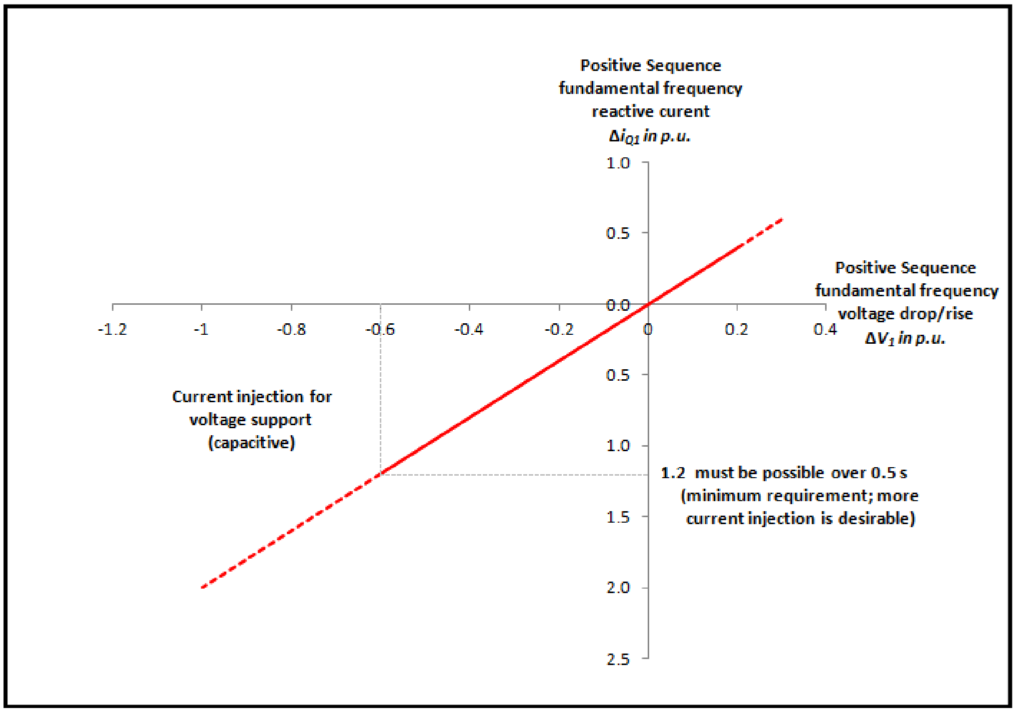


Figure 5-4 – Example Voltage Controller Characteristic

During Fault Ride-Through mode reasonable reduction of active current in favor of reactive current supply is allowed.

The positive sequence voltage drop or rise is defined with respect to the pre-fault 30-second-average voltage. It is allowed to calculate this value continuously including the low/high voltage periods (moving voltage average of the past 30 seconds).

$$\Delta v_1 = v_1,\text{Fault} - v_1\ (30\text{ s})$$

Figure 5-5 demonstrates the minimum dynamic requirements of the voltage controller based on the step response for the fast reactive current injection with the corresponding rise and settling times.

Rise Time < 30 ms
Settling Times < 60 ms

The step response of the reactive current must be well damped (damping ratio >5%) and should settle at the steady-state value.

$$iQ_{,1} = iQ_{,1}\,(t = 0) + k_1 \cdot \Delta v_1$$

where $iQ_{,1}\,(t = 0)$ represents the reactive current before the fault occurrence. The injected reactive current represents an addition to the steady-state reactive current supplied before the fault.

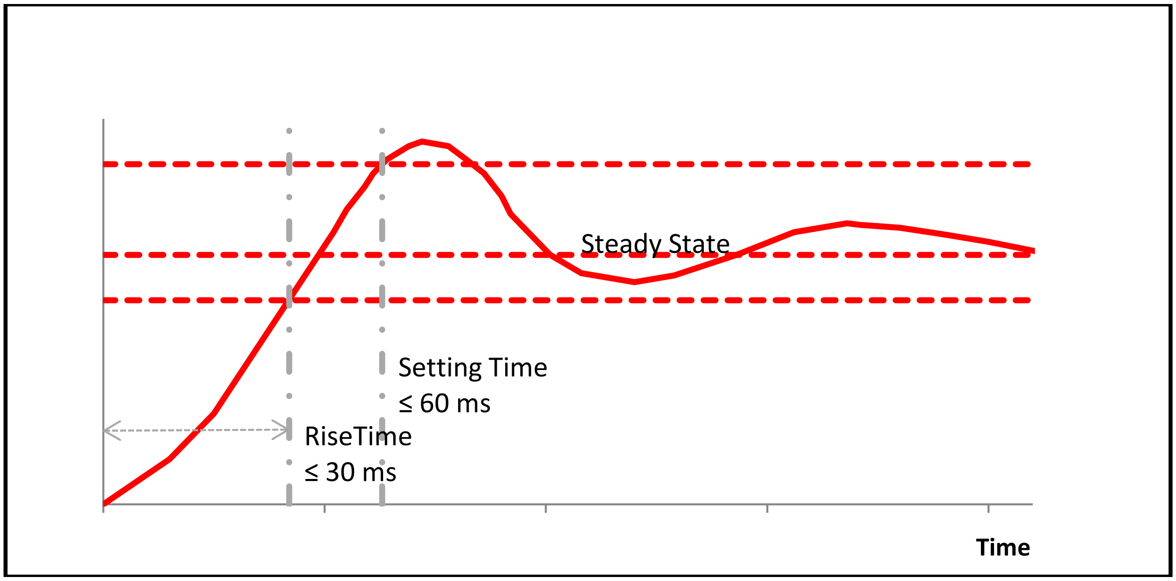


Figure 5-5 – Illustration of Min Step Response for Required Reactive Current

IRR-TIC 5.5. Grid Connected Transformer Configuration

IRRs shall provide on-load tap-changing (OLTC) facilities for all Grid Connected Transformers. All IRRs shall coordinate with NEPCO on the design specification for the performance of the tap-changing facility of the Grid Connected Transformer.

The IRR Grid Connected Transformers connection configuration must be pre-approved in writing by NEPCO.

Tap changing steps shall be proposed to NEPCO and pre-approved for the project, and shall be designed to ensure that the IRR units can comply with the IRR-TIC requirements.

IRR-TIC 5.6. Reactive Power Requirements

It must be possible to operate the IRR plant in reactive power control mode, and follow any operating point within the range cos φ = 0.95 leading under-excited (inductive) to cos φ = 0.85 lagging over-excited (capacitive) at PCC as shown in **Figure 5-6**. .

For active power supply below the nominal power the **Figure 5-6** indicates the minimum reactive power and power factor requirements.

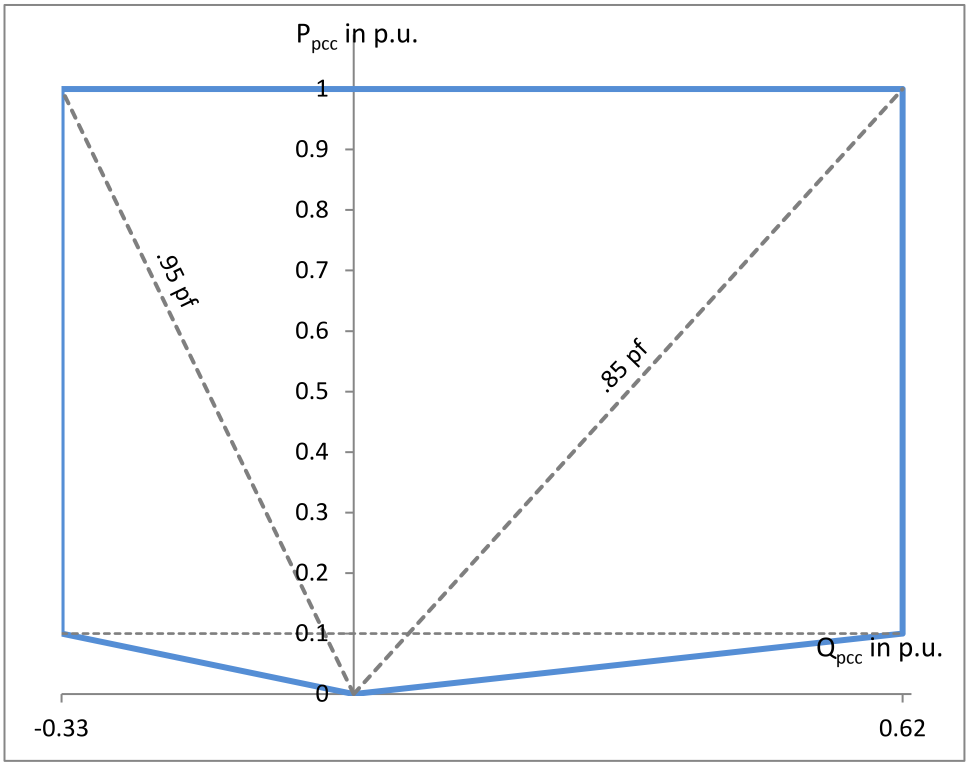


Figure 5-6 - Minimum PQ Diagram to be Fulfilled by IRR plant

Additionally the full lagging reactive capability of 0.85 pf of the rated IRR capacity shall be made available at 100% to 90% of the nominal voltage. The full leading reactive capability of 0 .95 pf of the rated IRR capacity shall be made available at 100% to 110% of the nominal voltage. The reactive support must be dynamic in nature for the equivalent of the rated plant (sum of IRR) capacity, and the rest of the reactive support may be provided by automatically switched capacitors or better at the point of interconnection.

The IRR shall be capable to provide reactive power support in any of three modes: AVR, power factor control, or reactive set point control. An implementation example for the steady-state Var settings and controller design are shown in Figure 5-7.

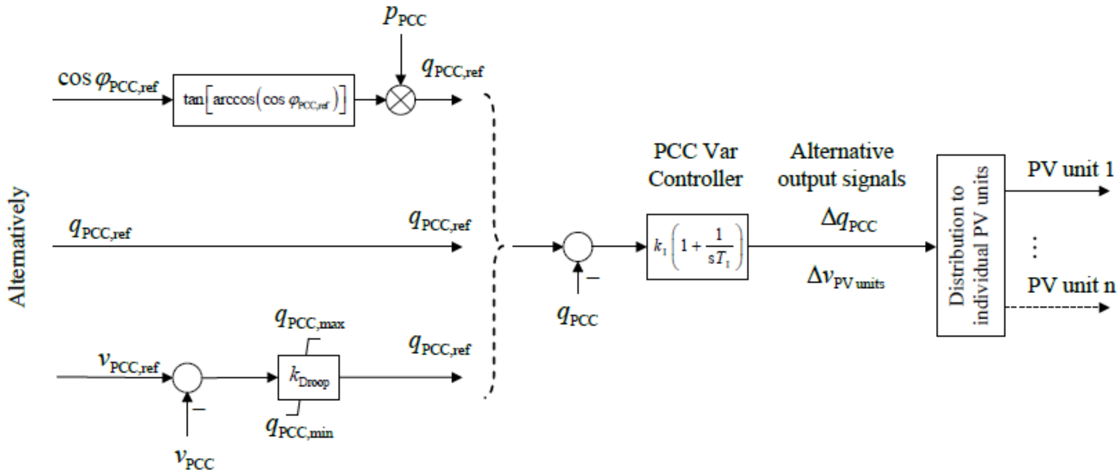


Figure 5-7 - Definition and Control of PCC Reactive Power

IRR-TIC 6. Voltage Flicker

Voltage Flicker is the rapid change in voltage that distorts or interferes with the normal sinusoidal voltage waveform of the Transmission Network. Such interference is a product of a relatively large current inrush when Apparatus, such as a large motor, is suddenly switched on, or resulting from the sudden increased Demand from for example welding equipment.

The current inrush acting over the Network impedance the voltage dip (sudden fall) and the corresponding voltage swell (sudden rise) when the Apparatus concerned is offloaded. IRRs are not allowed to introduce significant Voltage Flicker on the Transmission Network as measured at the PCC. The Voltage Flicker limits are contained in the following documents:

a) IEC/TR3 61000-3-7 “Assessment of emission limits for fluctuating loads in MV and HV power systems”.
b) IEC 868 / Engineering Recommendation P28 (pg 17) “Limits on voltage flicker short term and long term severity values”.
c) IEC 61400-21 “Measurement and assessment of power quality characteristics of grid connected wind turbines”
d) IEC 61000-3-7 “Electromagnetic Compatibility (EMC) - Part 3-7: Limits - Assessment Of Emission Limits For The Connection Of Fluctuating installations to MV, HV and EHV Power Systems”

Strict conformity with the IEC flicker curve according to IEC 61000-4-15 is required.

IRR-TIC 7. Harmonics

IRR-TIC 7.1. Harmonic Distortion

Harmonics are waveforms that distort the fundamental 50 Hz wave. The limits for harmonic distortion levels are given in the following documents:

a) IEC/TR3 61000-3-6 "Assessment of emission limits for distorting loads in MV and HV power systems".
b) IEC 61400-21 "Measurement and assessment of power quality characteristics of grid connected wind turbines"
c) IEC 61000-3-7 "Electromagnetic Compatibility (EMC) – Part 4-7 : Testing and Measurement Techniques – General Guide on Harmonics and Interharmonics measurements and instrumentation, for power supply systems and equipment connected thereto"

In particular IEC/TR3 61000-3-6 outlines the study process for harmonic distortion, and IEC 61000-3-7 provides guidelines for testing.

In general, the maximum total levels of harmonic distortion on the System under Normal Operation conditions, planned outages and fault outage conditions (unless during System Stress) shall not exceed the values shown in Table 7-1.

Table 7-1 – Total Harmonic Voltage Distortions

Voltage Level	Acceptable Voltage Harmonic Distortion Levels
33 kV	a Total Harmonic Distortion of 6.5% with no individual harmonic greater of 2.5%
132 kV	a Total Harmonic Distortion of 3% with no individual harmonic greater of 1.5%
400 kV	a Total Harmonic Distortion of 1.5% with no individual harmonic greater of 1%

Table 7-2 –Harmonic Voltage Distortions Planning Level at 33 kV

Indicative planning levels for harmonic voltages (in percent of the fundamental voltage) in 33 kv power systems					
Odd harmonics non-multiple of 3		Odd harmonics multiple of 3		Even harmonics	
Harmonic order h	Harmonic voltage %	Harmonic order h	Harmonic voltage %	Harmonic order h	Harmonic voltage %
5	5	3	4	2	1.8
7	4	9	1.2	4	1
11	3	15	0.3	6	0.5
13	2.5	21	0.2	8	0.5
$17 \leq h \leq 49$	1.9 x 17/h - 0.2	$21 \leq h \leq 45$	0.2	$10 \leq h \leq 50$	0.25 x 10/h + 0.22

The indicative planning level for the total harmonic distortion is THD_{MV} = 6.5%

Table 7-3 –Harmonic Voltage Distortions Planning Level at HV

Indicative planning levels for harmonic voltages (in percent of the fundamental voltage) in HV and EHV power systems					
Odd harmonics non-multiple of 3		Odd harmonics multiple of 3		Even harmonics	
Harmonic order h	Harmonic voltage %	Harmonic order h	Harmonic voltage %	Harmonic order h	Harmonic voltage %
5	2	3	2	2	1.4
7	2	9	1	4	0.8
11	1.5	15	0.3	6	0.4
13	1.2	21	0.2	8	0.4
$17 \leq h \leq 49$	1.2 x 17/h	$21 \leq h \leq 45$	0.2	$10 \leq h \leq 50$	0.19 x 10/h + 0.16

The indicative planning level for the total harmonic distortion is $THD_{HV\text{-}EHV} = 3\%$

If however harmonics that exceed above listed standards result from the operation of the IRRs electrical equipment which are verified by testing, the IRR system shall be disconnected until the harmonics are mitigated by the IRR in accordance with the above listed standards.

IRR-TIC 7.2. Sub-synchronous Oscillations

If, as a result of a detailed study conducted by NEPCO and/or the IRR engineer or consultant, identification and Study of Subsynchronous Resonance risk, NEPCO determines that protection or mitigation measures are necessary to protect the NEPCO System from SSR risk, the affected IRR shall install those protection or mitigation measures in accordance with this Section. For the purposes of this Section, “protection” shall refer to the installation and use of protective relays capable of isolating the affected transmission element or IRR from the NEPCO System in the event SSR is detected, and “mitigation” shall refer to the installation and use of any equipment or the implementation of any practice that may be used to mitigate or eliminate SSR risk, including, but not limited to, the following measures: Outage coordination, Special Protection Systems (SPSs), passive and dynamic SSR blocking filters, supplemental excitation damping controls, thyristor-controlled series capacitors, bypass series capacitors with the aid of low set gaps, and series capacitor segmentation.

IRR-TIC 8. Ramp Rate

The plant Control System shall be capable of controlling the ramp rate of its active power output with maximum active power per minute ramp rate set by NEPCO. Two ramp rate settings will be defined:

- The first is the active power ramp rate average over one (1) minute, with default at 20% per minute of unit nameplate capacity.
- The second ramp rate setting shall apply to the active power per minute ramp rate overage over ten (10) minutes.

These ramp rate settings shall be applicable for all ranges of operation including start up, normal operation and shut down, including when responding or released from an operator deployment.

IRR-TIC 9. Phase Imbalance & Negative Sequence Handling (Optional)

The negative sequence current control would enable the reduction or even total elimination of the negative sequence short circuit current in many modern wind turbines / solar inverters.

During unbalanced faults, e.g. line-to-line fault, full negative sequence current suppression control would lead to a line-to-line short circuit current in the range of the current of the loads connected to the grid or even to zero under no load conditions. The conventional protection devices would thus have difficulty to sense and clear the fault.

In order to overcome this problem, IRR are to be required to inject a certain level of inductive negative sequence short circuit current proportional to the negative sequence voltage. This will result not only in higher short circuit current but also in the reduction of the negative sequence voltage and thus better phase voltage symmetry.

Under normal operation, the maximum negative phase sequence component of the phase voltage of the power system should remain below 1%. A control can be implemented to support this requirement. The relevant standards are:

a) IEC 61000-3-13 “ELECTROMAGNETIC COMPATIBILITY (EMC) - PART 3-13: LIMITS - ASSESSMENT OF EMISSION LIMITS FOR THE CONNECTION OF UNBALANCED INSTALLATIONS TO MV, HV AND EHV POWER SYSTEMS”
b) IEC 61000-4-30 “ELECTROMAGNETIC COMPATIBILITY (EMC) - PART 4-30 : TESTING AND MEASUREMENT TECHNIQUES - POWER QUALITY MEASUREMENT METHODS”

In case of unbalanced grid faults the grid operator can require that IRR respond to a sudden negative sequence voltage increase with a fast negative sequence reactive current output. One possible option for the required negative sequence reactive current injection in a manner similar to section IRR-TIC 5.4

During unbalanced grid faults the priority between positive sequence active current, positive sequence reactive current and negative sequence reactive current may be determined as result of dynamic grid assessment.
The required step response of the controller in the negative sequence is identical with the dynamic time restrictions in the positive sequence.

IRR-TIC 10. Data Requirements & Studies

IRR-TIC 10.1. Studies

Studies shall be conducted by NEPCO or third party consultant pre-approved by NEPCO, according to the Study Guidelines outlined in Appendix 1. Additionally the IRR is required to provide, at a minimum, the data required in Appendix 2. Both Appendix 1 and Appendix 2 shall be revised as needed by NEPCO.

IRR-TIC 10.2. Technical Data

The IRR shall provide all the data required in Appendix 1 of this IRR-TIC document. This data must be provided in the Interconnection Application process, for the as-built plant, as well as whenever required to be updated by NEPCO.

IRR-TIC 10.3. Resource Forecasts

Resource forecasts shall be provided by the IRR. These forecasts, if required, shall be provided in a format and timescale as specified by NEPCO, and by means of an electronic interface in accordance with the reasonable requirements of NEPCO's data system.

IRRs shall engage fully with NEPCO to ensure that the necessary information is available to NEPCO for the production of wind or solar generation forecasts with the appropriate level of accuracy by NEPCO.

IRRs shall submit their MW availability declarations whenever changes in IRR availability occur or are predicted to occur. These declarations shall be submitted by means of an electronic interface in accordance with the reasonable requirements of NEPCO's data system.

IRR-TIC 11. Signals, Communications and Controls

Signals from Controllable IRR to NEPCO shall be provided for all the following groups, and shall be divided and provided accordingly

Signals List #1 - applies to all IRRs and includes the following:

- Active Power output (MW) at the lower voltage side of the Grid Connected Transformer;
- Reactive Power output/demand (+/-Mvar) at the lower voltage side of the Grid Connected Transformer;
- Voltage (in kV) at the lower voltage side of the Grid Connected Transformer;
- Grid Connected Transformer tap positions;
- Voltage Regulation Set-point (in kV);
- On/off status indications for all Reactive Power devices exceeding 5 Mvar

Signals List #2 - Availability Data;

Signals List #3 - Active Power Control Data;

Signals List #4 - Frequency Response System Data

Signals List #5 - Meteorological Data, applies to PV and WF;

IRR-TIC Appendix 1 Study Requirements

The following steady state analyses have to be performed by a power system analysis software such as PSS/E or DIgSILENT, taking into account the electrical equipment and configuration. The final results and the used models, including the validated user model have to be handed over to the grid operator. The studies must demonstrate the capability of the plant to meet all the grid code requirements outlined in this chapter. The Plant model shall comprise all facilities necessary for the generation of power from the IRR to be integrated in the system model.

Appendix 1.1 Steady State Studies

The analysis should be run under system intact N-0, as well as N-1 and any multiple contingencies provided by NEPCO, for the following scenarios:

- IRR disconnected
- IRR connected

The following are points that should be considered in steady state studies:

- Power flow and equipment (step-up transformers, transmission lines) loading verification throughout the transmission grid, and reporting any overloaded equipment.

- Voltage profile assessment and verification that voltages remain within the NEPCO operating range throughout the transmission grid, and reporting any voltage violations.

- Load flow data assessment of the transformers and cables and/or overhead lines (presented in a tabular form) within the project's ownership; and indicate if any of the equipment is overloaded

- Voltage-frequency operating range (Voltage Profile Assessment) verification of:
  - continuous operation of the plant for the full normal operating range of voltage at the PCC
  - continuous operation of the plant for the full normal operating range of system frequency

- Active Power Control verification of:
  - active power reduction by defined set point
  - active power reduction as a response to over frequency

- Reactive Power Compliance

- reactive power control verification
- power factor range and control capability
- verification of reactive power at the Point of Common Coupling
- (PCC) (Active and reactive power PQ capability)

- Short Circuit Analysis
  - determination of short-circuit current contributions
  - impact on existing transmission grid equipment and identification of any overloads
  - proposed switchgear ratings at the PCC

Appendix 1.2 Transient Analysis and Power Quality Studies

Developer shall review and test the generator dynamic model parameters, level of proposed IRR generator modeling as well as modeling of other IRRs.

- The models should fully represent the generator parameters
- Level of IRR generator modeling
- Modeling of other IRRs. If dynamic models of the plants are not available, developer may use generic models
- . Dynamic RMS simulation studies
  - full load simulation cases
  - partial load simulation cases
  - dynamic results for case of loss of proposed IRR project, showing system stability for various contingencies and other system disturbances as dictated by NEPCO.
- Low Voltage Ride-Through (LVRT) with respect to staying grid connected for various fault locations and types
  - possible combined implementation of reference tracking Var controller and fast voltage controller
- High Voltage Ride-Through (HVRT) for various fault locations and types of possible combined implementation of reference tracking Var controller and fast voltage controller

Appendix 1.3 Requirements concerning Harmonic Emissions and Grid Resonances

- Voltage flicker. If a flicker coefficient for the plant is not available for that purpose, then the study should at least calculate the voltage change at the point of interconnection with and without the IRR, to evaluate the impact of voltage in case of sudden change in the plant output. This should be done for n-0 as well as for critical contingency conditions.
- Harmonics
- Phase imbalance

IRR-TIC Appendix 2 Interconnection Request

1. This Interconnection Request is for (check one):
   - ☐ A proposed new Generating Facility.
   - ☐ An increase in the generating capacity or a Material Modification to an existing Generating Facility.

2. The Interconnection Customer provides the following information:

   a. Address or location, including the county, of the proposed new Generating Facility site or, in the case of an existing Generating Facility, the name and specific location, including the county, of the existing Generating Facility;

   Project Name: _____

   Project Location:
   Address: _____
   _____
   _____
   _____

   GPS Coordinates (decimal format):
   Latitude: _____ Longitude: _____

   b. Maximum net megawatt electrical of the proposed new Generating Facility or the amount of net megawatt increase in the generating capacity of an existing Generating Facility;

   Maximum net megawatt electrical output (MW): _____ ***OR***
   Net Megawatt increase (MW): _____

   c. Type of project (i.e., , wind, PV, etc.) and general description of the equipment configuration (if more than one type is chosen include net MW for each);

   ☐ Cogeneration _____ (MW)
   ☐ Wind _____ (MW)
   ☐ Photovoltaic _____ (MW)
   ☐ Storage
   Storage type (e.g. Pumped-Storage Hydro, Battery (w/type), etc.): _____
   Maximum Instantaneous Capability: _____ (MW)
   Total Storage Capability: _____ (MWh)
   Maximum Charge Duration: _____ (hours)
   Maximum Discharge Duration: _____ (hours)
   Charge/Discharge Cycle Efficiency: _____ (%)

   ☐ Other (please describe): _____ (MW)
   _____

General description of the equipment configuration (e.g. number, size, type, etc):

_____

d. Proposed In-Service Date (first date transmission is needed to the facility), Trial Operation date and Commercial Operation Date in MM/DD/YYYY format and term of service (**dates must be sequential**):

Proposed In-Service Date: _____
Proposed Trial Operation Date: _____
Proposed Commercial Operation Date: _____
Proposed Term of Service (years): _____

e. Name, address, telephone number, and e-mail address of the Interconnection Customer's contact person (primary person who will be contacted);

Name: _____
Title: _____
Company Name: _____
Address: _____
_____
_____
Phone Number: _____
Fax Number: _____
Email Address: _____

f. Approximate location of the proposed Point of Interconnection (i.e., specify transmission facility interconnection point name, voltage level, and the location of interconnection);

_____

g. Interconnection Customer data (set forth in Attachment A)

The Interconnection Customer shall provide to the NEPCO the technical data called for in IRR-TIC Appendix 1, Attachment A. One (1) copy is required.

3. Applicable deposit amount made payable to NEPCO

4. Evidence of site control and address(es) and contact information of site owner(s) (check one):

☐ Is attached to this Interconnection Request

6. This Interconnection Request is submitted by:

Legal name of the Interconnection Customer: _____

By (signature): ____

Name (type or print): _____

Title: _____

Date: _____

Appendix 1 - Attachment A Generating Facility Data

To IRR-TIC Appendix 1 Interconnection Request

Project Name:

Attachment A Generating Facility Data

To IRR-TIC Appendix 2 Interconnection Request

GENERATING FACILITY DATA

1. **Provide one set of original prints or soft copy on cd/flashdrive of the following:**

   A. Site drawing to scale, showing generator location and Point of Interconnection.
   B. Single-line diagram showing applicable equipment such as generating units, step-up transformers, auxiliary transformers, switches/disconnects of the proposed interconnection, including the required protection devices and circuit breakers. For wind and photovoltaic generator plants, the one line diagram should include the distribution lines connecting the various groups of generating units, the generator capacitor banks, the step up transformers, the distribution lines, and the substation transformers and capacitor banks at the Point of Common Coupling with the NEPCO Controlled Grid.

2. Generating Facility Information

A. Total Generating Facility rated output (MW): _____
B. Generating Facility auxiliary Load (MW): _____
C. Project net capacity (A.-B.) (MW): _____
D. Standby Load when Generating Facility is off-line (MW): _____
E. Number of Generating Units: _____
(Please repeat the following items for each generator)
F. Individual generator rated output (MW for each unit): _____
G. Manufacturer: _____
H. Year Manufactured: _____
I. Nominal Terminal Voltage (kV): _____
J. Rated Power Factor (%):_____
K. Type (Induction, Synchronous, D.C. with Inverter): _____
L. Phase (three phase or single phase): _____
M. Connection (Delta, Grounded WYE, Ungrounded WYE, impedance grounded): _____
N. Generator Voltage Regulation Range (+/- %): _____
O. Generator Power Factor Regulation Range: _____

7a. **Wind Generators**

Number of generators to be interconnected pursuant to this Interconnection Request: _____

Average Site Elevation: _____ ☐Single Phase ☐Three Phase

Field Volts: _____
Field Amperes: _____
Motoring Power (MW): _____
Neutral Grounding Resistor (if applicable): _____
I22t or K (Heating Time Constant): _____
Rotor Resistance: _____
Stator Resistance: _____
Stator Reactance: _____
Rotor Reactance: _____
Magnetizing Reactance: _____

Short Circuit Reactance: _____
Exciting Current: _____
Temperature Rise: _____
Frame Size: _____
Design Letter: _____
Reactive Power Required in Vars (No Load): _____
Reactive Power Required in Vars (Full Load): _____
Total Rotating Inertia, H: _____ Per Unit on 100 MVA Base

Note: A completed dynamic model must be supplied with the Interconnection Request. If other data sheets are more appropriate to the proposed device then they shall be provided and discussed at the Scoping Meeting.

8. Generator Short Circuit Data

For each generator model, provide the following reactances expressed in p.u. on the generator base:

- X"1 – positive sequence subtransient reactance: _____p.u**
- X2 – negative sequence reactance: _____p.u**
- X0 – zero sequence reactance: _____

Generator Grounding (select 1 for each model):

A. ☐ Solidly grounded
B. ☐ Grounded through an impedance
(Impedance value in p.u on generator base R: _____p.u. X: _____p.u.)
C. ☐ Ungrounded

9. Step-Up Transformer Data

For each step-up transformer, fill out the data form provided in Table 1.

10. Interconnection Facilities Line Data

There is no need to provide data for new lines that are to be planned by the Participating TO. However, for transmission lines that are to be planned by the generation developer, please provide the following information:

Nominal Voltage: _____kV
Line Length: _____miles
Line termination Points: _____
Conductor Type: _____ Size: _____
If bundled. Number per phase: _____, Bundle spacing: _____in.
Phase Configuration. Vertical: _____, Horizontal: _____
Phase Spacing: A-B: _____ft., B-C: _____ft., C-A: _____ft.
Distance of lowest conductor to Ground at full load and 40°C: _____ft
Ground Wire Type: _____ Size: _____ Distance to Ground: _____ft
Attach Tower Configuration Diagram
Summer line ratings in amperes (normal and emergency) _____
Positive Sequence Resistance (R): _____ p.u.** (for entire line length)
Positive Sequence Reactance: (X): _____ p.u**(for entire line length)
Zero Sequence Resistance (R0): _____ p.u.** (for entire line length)
Zero Sequence Reactance: (X0): _____ p.u** (for entire line length)
Line Charging (B/2): _____ p.u**
** On 100-MVA and nominal line voltage (kV) Base

10a. For Wind/photovoltaic plants, provide collector System Equivalence Impedance Data Provide values for each equivalence collector circuit at all voltage levels.

Nominal Voltage: _____
Summer line ratings in amperes (normal and emergency) _____
Positive Sequence Resistance (R1): _____ p.u. ** (for entire line length of each collector circuit)
Positive Sequence Reactance: (X1): _____ p.u** (for entire line length of each collector circuit)
Zero Sequence Resistance (R0): _____ p.u. ** (for entire line length of each collector circuit)
Zero Sequence Reactance: (X0): _____ p.u** (for entire line length of each collector circuit)
Line Charging (B/2): _____ p.u** (for entire line length of each collector circuit)
** On 100-MVA and nominal line voltage (kV) Base

11. Inverter-Based Machines

Number of inverters to be interconnected pursuant to this Interconnection Request: _____

Inverter manufacturer, model name, number, and version:

_____

List of adjustable set points for the protective equipment or software:

_____

Maximum design fault contribution current:

_____

Harmonics Characteristics:

_____

Start-up requirements:

_____

Note: A completed dynamic model must be supplied with the Interconnection Request. If other data sheets are more appropriate to the proposed device then they shall be provided and discussed at the Scoping Meeting.

12. Load Flow and Dynamic Models (to be provided on DVD, CD, or USB Flash Drive):

Provide load flow model for the generating plant and its interconnection facilities in PSS/E or DIgSILENT format, including new buses, generators, transformers, interconnection facilities. An equivalent model is required for the plant with generation collector systems. This data should reflect the technical data provided in this Attachment A.

TABLE 1

TRANSFORMER DATA
(Provide for each level of transformation)

UNIT_____

NUMBER OF TRANSFORMERS_____ PHASE _____

RATING	H Winding	X Winding	Y Winding
Rated MVA	_____	_____	_____
Connection (Delta, Wye, Gnd.)	_____	_____	_____
Cooling Type (OA,OA/FA, etc) :	_____	_____	_____
Temperature Rise Rating	_____	_____	_____
Rated Voltage	_____	_____	_____
BIL	_____	_____	_____
Available Taps (% of rating)	_____	_____	_____
Load Tap Changer? (Y or N)	_____	_____	_____
Tap Settings		_____	_____
IMPEDANCE	H-X	H-Y	X-Y
Percent	_____	_____	_____
MVA Base	_____	_____	_____
Tested Taps	_____	_____	_____
WINDING RESISTANCE	H	X	Y
Ohms	_____	_____	_____

CURRENT TRANSFORMER RATIOS

H_____ X_____ Y_____ N_____

Percent exciting current at 100% Voltage _____ 110% Voltage _____

Supply copy of nameplate and manufacture's test report when available