Intermittent Renewable Resources (Wind and PV) Distribution Connection Code (DCC) At Medium Voltage (MV)

Document	Version	Date
IRR-DCC-MV	Version 1	May 24, 2015

IRR-DCC-MV 1. Introduction

All Generators connecting to the Distribution System must comply with the Distribution Code governing the electric distribution systems in Jordan. The Distribution Code was originally developed assuming synchronous generators. At the time this code was provided there is an influx of development in renewable generation particularly wind and solar photovoltaic (PV). Intermittent Renewable Resources (IRR), particularly asynchronous Photovoltaic generators and Wind Turbine (WT) generators, merit immediate special code provisions to address their immediate connection requirements.

This document, Intermittent Renewable Resource (IRR) Distribution Connection Code (DCC) at Medium Voltage (MV), establishes the technical Connection Code rules which IRRs must comply with in relation to their connection requirements to the Medium Voltage (MV) Distribution Network.

At the time of writing this chapter the regulatory body in Jordan lacks the following procedures and code at Distribution System level for IRR, which shall be work in progress as the system is reformed.

- Comprehensive Guidelines for Connection.
- Revisions and adoption of Distribution Code
- Connection Requirements at Low Voltage.
- Operation and Planning Code for IRRs

IRR-DCC-MV 2. Scope

IRR-DCC-MV 2.1. General

IRR-DCC-MV applies to IRRs connecting to the Medium Voltage (MV) Distribution Network, where MV, as defined in the Distribution Code, is for voltage levels greater than one 1 kV and up to 33 kV.

Directives & Guidelines issued by the EMRC on connection of IRRs to the Distribution System also provide some requirements and other instructions that compliment this code and must be enforced.

Where the IRR-DCC-MV may conflict with the Distribution Code, the IRR-DCC-MV shall override. Language in the Connection Agreement with the DISCO and Power Purchase Agreement for an IRR shall override both the IRR-DCC-MV and the Distribution code.

IRRs must also comply with any additional technical requirements from the DISCOs where applicable which may include reference to ENA recommendations as needed while the regulatory procedures and code governing connection of resources to the distribution system are restructured.

IRR-DCC-MV 2.2. Affected Systems

By nature of connection of the DISCO's network to NEPCO, NEPCO's system may become affected by the connection of the IRR to the Distribution Network. The following two conditions shall deem the IRR to result in affecting NEPCO's network:

- If the IRR is 5 MW or larger, as defined in the Grid Code, and/or
- If the DISCO determines, through either initial screening study or full system impact study that the IRR connection may result in Reverse Power Flow into any electrical equipment that is owned by NEPCO; the screening study or full system impact study shall take into account any other IRRs that are existing on the Distribution Network and/or are in the process of applying for connection.

In case of identification of affected systems, the DISCO to which the IRR is interconnecting shall notify NEPCO of the IRR connection application and data. NEPCO in turn shall asses the need to perform its own studies and due diligence, perform such studies where applicable, and may require the application of its requirements and standards, including but not limited to the requirements under IRR-TIC.

IRR-DCC-MV 2.3. Applicability Matrix

Three categories of IRRs interconnecting to the Distribution System are presented as Types A, B and C shown below in Table 2-1. Type A is further divided into three types depending on the connection voltage. Table 2-2 provides a matrix of grid code applicability for each type of IRR. Note that Type C IRR is connected to a dedicated NEPCO renewable generation collection station that does not serve any DISCO load and therefore must comply with all NEPCO IRR-TIC requirements.

Connection at MV is currently limited to 15 MW. Projects larger than 15 MW shall follow connection with the Transmission Network.

IRRs interconnecting at low voltage are currently governed by the Distribution Code and supplemented by requirements that the DISCOs impose relying heavily on ENA recommendations.

Table 2-1 – Generator Types

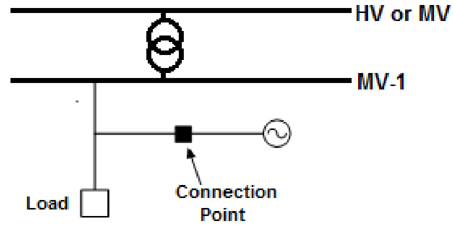
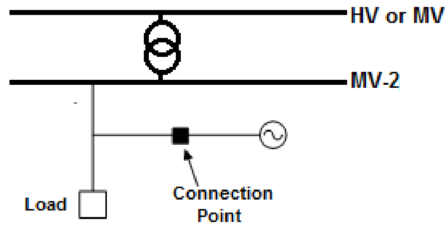
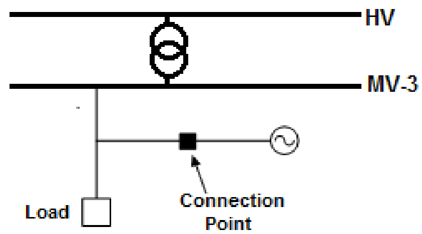
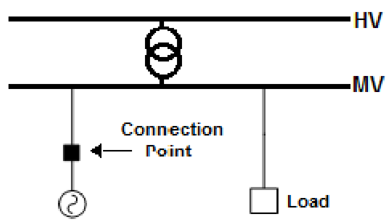
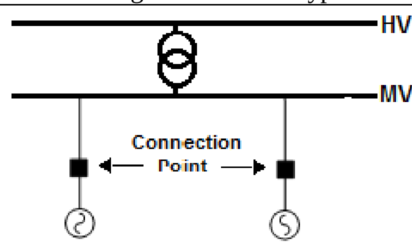
Type	Schematic	Project Size
<u>Type A-1</u>: Connected to the MV distribution on an existing feeder with load. **MV-1: 6.6 kV**	 Figure 2-1 –IRR Type A-1	Up to 2 MW
<u>Type A-2</u>: Connected to the MV distribution on an existing feeder with load. **MV-2: 11 kV**	 Figure 2-2 –IRR Type A-2	Up to 3 MW
<u>Type A-3</u>: Connected to the MV distribution on an existing feeder with load. **MV-3: 33 kV**	 Figure 2-3 –IRR Type A-3	Up to 10 MW
<u>Type B</u>: Connected to the MV distribution via a DISCO owned or operated dedicated feeder that serves only the IRR. Other loads are connected to the MV source however through other feeders. **MV: 33 kV**	 Figure 2-4 –IRR Type B	Up to 15 MW
<u>Type C</u>: Connected at MV to a dedicated NEPCO renewable generation collection substation directly or through a privately owned line. There are no loads connected at the MV substation level. **MV: 33 kV**	 Figure 2-5 –IRR Type C	NEPCO requirements

Table 2-2 – Code Applicability Matrix

Code Description	Section	Type A	Type B	Type C
NEPCO IRR-TIC		Affected System	Affected System	ALL
Frequency Tolerance requirement	IRR-DCC-MV 4.1	ALL	ALL	
Frequency Relaying Requirement	IRR-DCC-MV 4.2	>0.5 MW Or more than 2 IRR Units at PCC	>0.5MW Or more than 2 IRR Units at PCC	
Active Power Requirement	IRR-DCC-MV 4.3	ALL	>ALL	
Governor – Primary Frequency Response (PFR)	IRR-DCC-MV 4.4	5 MW or larger	5 MW or larger	
Voltage Tolerance Requirement at PCC	IRR-DCC-MV 5.1	ALL	ALL	
Voltage Relaying Requirement	IRR-DCC-MV 5.2	>0.5MW Or more than 2 IRR Units at PCC	>0.5MW Or more than 2 IRR Units at PCC	
Voltage Step Limit	IRR-DCC-MV 5.3.1	ALL	ALL	
Flicker Standards	IRR-DCC-MV 5.3.2	ALL	ALL	
Fault and Zero Voltage Ride through Requirement	IRR-DCC-MV 5.4	>0.5 MW	>0.5 MW	
Voltage Regulation (AVR)	IRR-DCC-MV 5.5	>0.5 MW	>0.5 MW	
Reactive Power Requirement	IRR-DCC-MV 5.6	ALL	ALL	
Power Transformer	IRR-DCC-MV 5.7	ALL	ALL	
Power Factor	IRR-DCC-MV 6	ALL	ALL	
Harmonics	IRR-DCC-MV 7	ALL	ALL	
Phase Imbalance and Negative Sequence Handling	IRR-DCC-MV 8	>2MW	>2MW	
Ramp Rate	IRR-DCC-MV 9	>2MW	>2MW	
Islanding Requirements	IRR-DCC-MV 10.1	ALL	ALL	
Anti Islanding Relay or Transfer Scheme	IRR-DCC-MV 10.2	>0.5MW Or more than 2 IRR Units at PCC	>0.5MW Or more than 2 IRR Units at PCC	
System Impact Studies	IRR-DCC-MV 11	ALL	ALL	

IRR-DCC-MV 3. Definitions and Acronyms

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

Active Power: The multiple of the component of alternating current and voltage that equate to true power, 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 the DISCO/NEPCO**.**

Active-Power Control Set-point: The maximum amount of Active Power in MW, set by DISCO/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 or constrained.

DISCO: Distribution Company operating electric distribution lines in the country of Jordan

Distribution Code: means this Distribution Code established by the ERC as revised and amended from time to time with the approval of, or by the direction of, the ERC.

Distribution System: used interchangeable with Distribution Network means a system consisting of cables, overhead lines, electrical Plant and Apparatus, having a design voltage of 33 kV or lower, used for the distribution of electric power from Connection Points between the Transmission System and the Distribution System to the point of delivery to Consumers or other Users, but shall not include any part of a Transmission System, as defined in the General Electricity Law.

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

Grid Code: Has the meaning given to it in the General Electricity Law. NEPCO Transmission Grid Code, First Amendment Version, February 2010

HVRT: High voltage ride-through

IRR-TIC: Interruptible Renewable Resource Transmission Connection Code

LVRT: Low voltage ride-through

MV: 1 kV up to 33 kV.

LV: A voltage level not exceeding 1 kV.

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

PCC: Point of Common Coupling defined as the point of change of ownership from the IRR facilities to the DISCO facilities. It can reach up to the incoming cable sealing ends of the IRR facilities.

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 generator 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 current and the sine of the phase angle between them, 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.

Reverse Power Flow: In the context of this code, Reverse Power Flow shall mean positive power flow in MW from the Distribution Network into the Transmission Network

IRR: Intermittent Renewable Resource. A generation resource that can only produce energy from renewable resources such as wind or solar. In the Distribution code and where applicable, the User is the IRR.
IRR Unit: One inverter block (for PV) or one turbine (for wind) along with its transformer, which is the basic unit generator in an IRR plant, where the latter may include several of such units in a collection system configuration.
IRR-DCC-MV: Renewable Resources – Distribution Connection Code, as presented in this document in whole or in part
SSI: Sub-synchronous interference
SSR: Sub-synchronous resonance
Transmission System: has the meaning given to it in the General Electricity Law.
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-DCC-MV 4. Frequency Requirements

IRR-DCC-MV 4.1. Frequency Tolerance requirement

Under extreme system fault conditions all IRR units must be disconnected at a frequency greater than 52 Hz. At a frequency less than 47 Hz they may be disconnected at generator discretion. The IRR shall also be capable of operating within the frequency tolerance ranges shown in Table 4-1.

Table 4-1 - Frequency Protection Setting Requirements

Frequency Range	Delay to Trip
52.0 Hz ≤ Freq	.5s
51.5 Hz < Freq < 52.0 Hz	90s
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 Distribution System during rate of change of System Frequency of values at least up to and including 0.5 Hz per second
- No additional IRR shall be started while the System Frequency is above 50.2 Hz.
- An IRR which has disconnected from the Distribution System must be brought back on load as fast as technically possible: a) after recovery from a high frequency event and the frequency drops back below 50.5 Hz, or b) after recovery from a low frequency event and frequency rises back above 49.5 Hz.

IRR-DCC-MV 4.2. Frequency Relaying Requirement

The IRR shall provide a G59 relay (compliant with the latest G59 specifications release) at the PCC programmed such that the automatic removal of the IRR from DISCO's Distribution System meets the requirements shown in Table 4-1. The operational characteristics of the relay must be coordinated with other control systems of the IRR (such as excitation, frequency (speed) governor response, and other controls where applicable).

IRR-DCC-MV 4.3. Active Power Requirement

IRR plants shall have the capability of operating at reduced power output after receiving a signal from the DISCO.

The IRR must be capable of reducing its active power in steps, where each step shall be no larger than 10% of 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 DISCO. This target value shall be provided as a percentage of the nameplate capacity.

The DISCO shall not interfere in the control of the IRR; it shall only be responsible for providing the signal to the IRR which in turn shall execute the active power control requirement.

IRR-DCC-MV 4.4. Governor – Primary Frequency Response (PFR)

IRRs to which this requirement applies are required to provide the necessary equipment to comply. The requirement shall be activated when needed in coordination with NEPCO and in accordance with NEPCO's requirements.

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 System frequency deviations. The PFR shall be similar to the droop characteristic of governor systems used by conventional steam generators. The governor droop shall be set by the DISCO 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, and E shall be defined by NEPCO. The default requirements are for A and B to be at 100%, unless specified otherwise by NEPCO.

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 drop 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 generator's instantaneously available capacity per Hz as illustrated in Figure 4-2 .

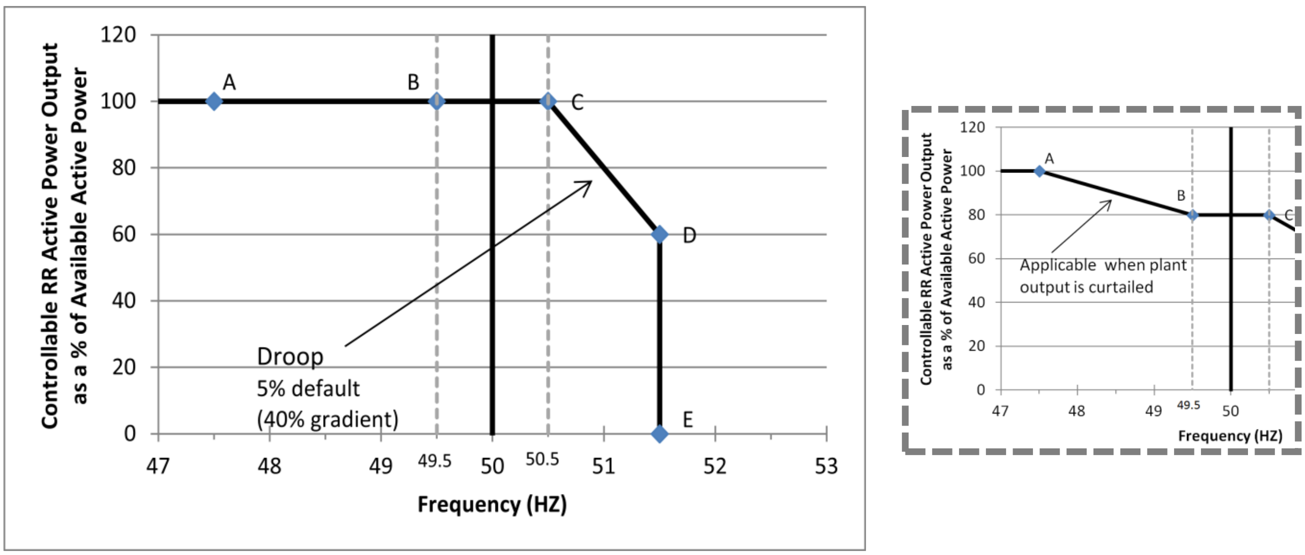
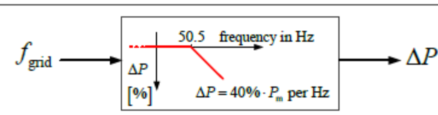


Figure 4-1 - Power-Frequency Response Curve



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

P_m instantaneously available power

ΔP power reduction

f_{grid} grid frequency

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

At $f_{grid} \leq 47.5\ \text{Hz}$ and $f_{grid} \geq 51.5\ \text{Hz}$ disconnection from grid

Figure 4-2 – <u>Default drop 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.

Under normal System Frequency ranges, the IRR shall operate with an Active Power output as set by the line ‘B’ - ‘C’. If the 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’. Where the Distribution 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’.

Once the Distribution 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 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 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 the NEPCO.

IRR-DCC-MV 5. Voltage Requirements

IRR-DCC-MV 5.1. Voltage Tolerance Requirement at PCC

IRR plant shall remain continuously connected to the Distribution Network for system voltages at +/- 10% of nominal at maximum Available Active Power or controlled Active Power output for normal and disturbed system conditions.

Table 5-1 describes the operating range and trip setting requirements of the IRR in relation to the voltage at the PCC.

Table 5-1 –IRR Plant Voltage Protection Setting Requirements at the PCC

Voltage Range (% $V_{nominal}$)	Delay to Trip
V= 119%	0.5s
V= 114%	1s
90 ≤ V ≤ 110	Continuous Operation
V = 87%	2.5s
V = 81%	0.5s

IRR shall also be capable of staying online for step changes in Distribution System voltage of up to 10 %.

The IRR shall provide at least 90 % of its maximum Available Active Power within no less than 30 seconds after the Distribution System Voltage recovers to the normal operating range.

IRR-DCC-MV 5.2. Voltage Relaying Requirement

The IRR shall provide a G59 relay (compliant with the latest G59 specifications release) at the PCC programmed such that the automatic removal of the IRR from DISCO's Distribution System meets the requirements shown in Table 5-1, and ensure that the IRR plant is capable of satisfying these requirements and must be coordinated with other control systems of the IRR.

Where LVRT is required, the relay settings shall be such that the plant will comply with the LVRT settings.

IRR-DCC-MV 5.3. Voltage Flicker

Voltage Flicker is the rapid change in voltage that distorts or interferes with the normal sinusoidal voltage waveform of the Distribution Network. Such interference is a product of a relatively large current inrush when Apparatus, such as a large motor or generator, is suddenly switched on.

The current inrush acting over the Network impedance results in a voltage dip (sudden fall) and/or voltage swell (sudden rise), therefore the Voltage Flicker, as well as when the Apparatus concerned is off-loaded. IRRs are not allowed to introduce significant Voltage Flicker on the Distribution Network as measured at the PCC, in accordance with the requirements of the following paragraphs.

5.3.1 Voltage Step Limit

The voltage step limit at the PCC caused by the sudden loss or starting of the IRR, shall not exceed 3% of the nominal voltage, measured at the PCC at any instance regardless of frequency of occurrence. The DISCO shall take into consideration operation of all other User's equipment on the system in evaluation of this limit.

For the purpose of this code a voltage step change should be considered to be the change from the initial voltage level to the resulting voltage level after all the IRR automatic voltage regulator and static VAR compensator actions, and transient decay have taken place, but before any other automatic or manual tap-changing and switching actions have commenced.

5.3.2 Flicker Standards

IRRs are not allowed to introduce significant Voltage Flicker on the Distribution Network as measured at the PCC, per the standards listed below.

The Voltage Flicker limits constraints set in the following documents must be further observed:

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"

The Flicker severity at the PCC of any IRR shall not be above the maximum values stated in IEC 61000-3-7 Standard for more than 3 % of the measured period. The maximum emission limits produced by any IRR shall be below the maximum values stated in IEC 61000-3-7 Standard.

In the event that the IRR operates outside the above specified limits causing annoyance or other injurious effects either to another User, or to the Distribution System, the DISCO shall give reasonable notice to remedy the defect and the IRR shall remedy the defect at its own expense. In determining the period of notice, the DISCO shall have regard to the nature and degree of noncompliance, the nature and degree of annoyance or other injurious effects as well as the prescriptions stated in the Distribution Performance Standards. The DISCO shall have the right to disconnect the IRR in the event that the IRR does not comply with such notice.

IRR-DCC-MV 5.4. Fault and Zero Voltage Ride through Requirement

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 5-1.

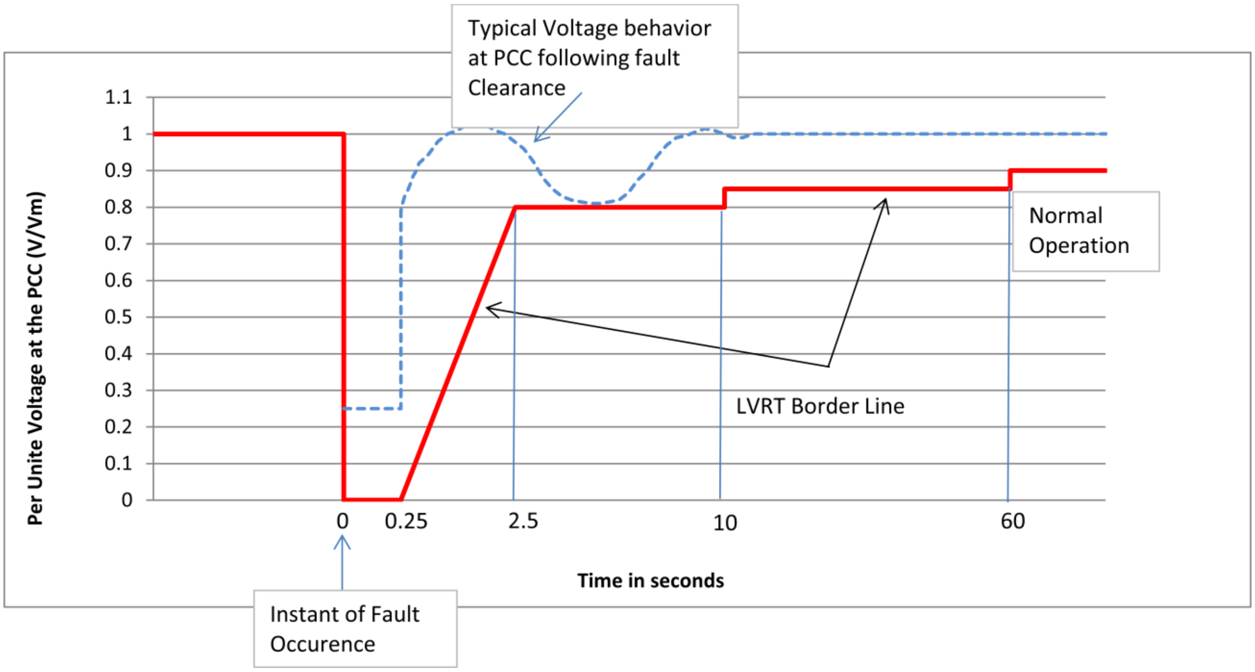


Figure 5-1 - Voltage versus Time profile at PCC for LVRT

During the fault ride through Voltage dip the IRR shall provide Active Power in proportion to retained Voltage and maximize reactive current to the Distribution System without exceeding IRR limits. The maximization of reactive current shall continue for at least 250 ms or until the Distribution System Voltage recovers to within the normal operational range of the Distribution System, whichever occurs sooner. IRRs must survive any incident of this severity in the voltage dip and duration.

The IRR shall provide at least 90 % of its maximum Available Active Power as quickly as the technology and resource allows, after the Distribution System Voltage recovers to the normal operating range.

IRR-DCC-MV 5.5. Voltage Regulation (AVR)

A form of voltage regulation may be required and specified by the DISCO after system studies are completed. The 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-DCC-MV 5.6. Reactive Power Requirement

It must be possible to operate the IRR plant in reactive power control mode, and at least follow any operating point within the range cos φ = 0.88 leading under-excited (inductive) to cos φ = 0.88 lagging over-excited (capacitive) at PCC as shown in Figure 5-2, and in such a way to maintain acceptable distribution system power factor.

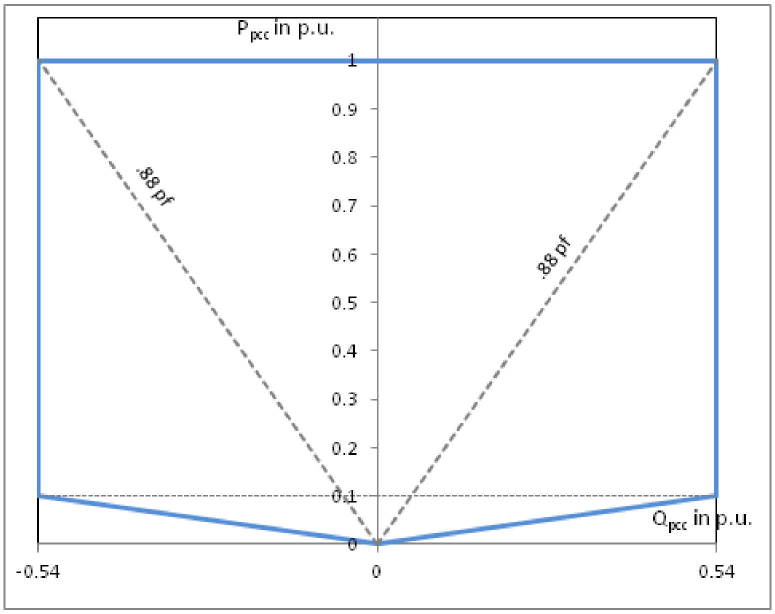


Figure 5-2 - Minimum PQ Diagram to be Fulfilled by IRR plant

Additionally the full lagging reactive capability of 0.88 pf of the nameplate rated IRR capacity shall be made available at 100% to 95% 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 105% of the nominal voltage. The reactive support must be dynamic in nature for the equivalent of the rated plant (sum of IRR units) capacity, and the rest of the reactive support may be provided by automatically switched capacitors or better at the point of connection.

The method of control and deployment of the reactive capability shall be determined by the System Impact Studies.

The reactive support must by dynamic in nature unless otherwise specified in the System Impact Study results and project Connection Agreement

For active power supply below the nominal power Figure 5-2 indicates the minimum reactive power and power factor requirements.

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 5-3.

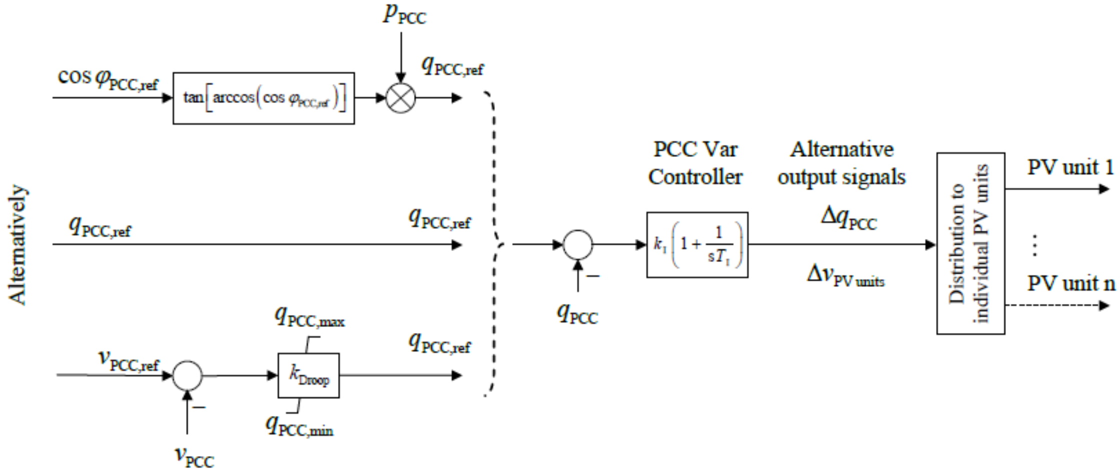


Figure 5-3 - Definition and Control of PCC Reactive Power

IRR-DCC-MV 5.7. Power Transformer Configuration

IRRs shall provide on-load tap-changing (OLTC) facilities for main central grid connected Power Transformer of the IRR plant at the PCC. All IRRs shall coordinate with the DISCO on the design specification for the performance of the tap-changing facility of the Power Transformer.

The IRR Power Transformers connection configuration must be pre-approved in writing by DISCO.

IRR-DCC-MV 6. Power Factor

As an alternative to operating the IRR in Voltage Control model, the DISCOs may require the IRR to operate in Power Factor control mode where the IRR shall operate to maintain of power factor anywhere between .88 lagging to 0.88 leading, as measured at the PCC and as requested by the DISCO. The pf set point shall be dictated by the DISCO where applicable in order to maintain a fixed pf at the PCC.

IRR-DCC-MV 7. Harmonics

IRR-DCC-MV 7.1. Harmonic Distortions

Harmonics are waveforms that distort the fundamental 50 Hz wave. The limits, assessment, planning, testing and measurement for harmonic distortion levels are given in the following documents:

a) IEC/TR 61000-3-6 “Electromagnetic Compatibility (EMC) – Part 3-6: Limits– Assessment of emission limits for the connection of distorting installations to MV, HV and EHV power systems”.
b) IEC/TR 61000-3-7 “Electromagnetic Compatibility (EMC) – Part 3-7: Limits– Assessment of emission limits for the connection of distorting installations to MV, HV and EHV power systems”.

c) IEC 61000-4-7 “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”
d) IEC 61400-21 “Measurement and assessment of power quality characteristics of grid connected wind turbines”

In particular IEC/TR 61000-3-6&7 outline the limits, assessment and study process for harmonic distortion, and IEC 61000-4-7 provides guidelines for testing, measurement and instrumentation.

In general, the maximum total levels of harmonic distortion on the MV system under normal operation conditions, planned outages and fault outage conditions (unless during system stress) shall not exceed total harmonic distortion levels of 6.5% with no individual harmonic greater than 5% as outlined in Table 7-1.

Table 7-1 – Harmonic Voltage Distortions Planning Level for MV

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 ≤ h ≤ 49	1.9 x 17/h - 0.2	21 ≤ h ≤ 45	0.2	10 ≤ h ≤ 50	0.25 x 10/h + 0.22

The indicative planning level for the total harmonic distortion is THDMV = 6.5%

Furthermore the addition of the IRR shall not result in the total aggregate harmonic distortion on the DISCO’s system at the PCC to exceed the acceptable levels, while taking into account all other IRR and Generators on the system. In instances where several IRRs are located in the vicinity of each other, the total harmonic contribution shall not exceed the above requirements. If required, allocation of emission limits shall be calculated in accordance to IEC 61000-3-6 for allocating emissions to distorting installations as described in section 8.2.2. Measurements shall follow the recommendations in IEC 61000-4-7.

Measurements may be taken by the DISCO at the IRRs Connection Point. Measurements shall be taken in accordance with methodologies of IEC 61000-4-7 lasting for at least 48 hours taken at 10 minute intervals.

In the situation where current harmonic measurements are necessary as may be requested by the DSICO, the harmonic current limits shall be derived from the harmonic voltage limits in accordance with IEC 61000-3-6 section 6.4 or in accordance with the harmonic current limits provided in the Distribution Code.

In the event that the IRR Equipment operates outside the above specified limits causing annoyance or other injurious effects either to another User, or to the Distribution System, the DISCO shall give reasonable notice to remedy the defect and the IRR shall remedy the defect at its own expense. In determining the period of notice, the DISCO shall have regard to the nature and degree of non-compliance, the nature and degree of annoyance or other injurious effects as well as the prescriptions stated in the Distribution Performance Standards. The DISCO shall have the right to disconnect the IRR Equipment in the event that the User does not comply with such notice.

IRR-DCC-MV 7.2. Interharmonics

Interharmonics Interharmonics are defined as components with frequencies between two consecutive harmonics or those components that are not integer multiples of the system fundamental frequency. Interharmonics are primarily caused by:

a) Power electornic converters with switching frequencies not synchronized to the system frequency, e.g. inverter drives, PWM inverters, active filters, power conditioning converters.
b) Rapidly changing of the load current or voltage, e.g. arc furnaces, arc loads.

In order to limit the system impact of interharmonics, these types of harmonics must be limited to 0.2% of the fundamental frequency per IEC 61000-3-6 section 10, whith measurement guidelines to follow recommendations in IEC 61000-4-7.

IRR-DCC-MV 8. Phase Imbalance and Negative Sequence Handling

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 (unsymmetrical) 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%. Additionally 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.

The DISCO therefore may require the IRR to implement a fast voltage control under unbalanced grid fault to respond with a fast negative sequence reactive current output. The control will be such that the negative sequence current would respond to the negative sequence voltage change.

The relevant standards for guidance and compliance 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”

IRR-DCC-MV 9. 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 the DISCO. 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 average 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-DCC-MV 10. Islanding

IRR-DCC-MV 10.1. Anti-Islanding Requirements

Under no conditions is the IRR permitted to be in an islanded situation with any part of the Distribution System. Islanding occurs when part of the Distribution System, to which the IRR is connected, during emergency conditions, becomes detached from the rest of the Distribution System as described in ANSI/IEEE Std. 1547-2003. In order to eliminate this risk, the following shall be implemented:

- The IRR must be capable of tripping off line in accordance with the DISCO, upon loss of main power (LoM) from the grid. It is the responsibility of the IRR to incorporate the most appropriate technique or combination of techniques to detect a loss of main power event in its protection systems to achieve disconnection of the Generating Plant from the Distribution System. This will be based on knowledge of the IRR, site and network load conditions.

- If no facilities exist for the subsequent re-synchronization with the rest of the Distribution System then the IRR shall under DISCO instruction ensure that the IRR is disconnected for re-synchronization.

IRR-DCC-MV 10.2. Anti-Islanding Relays and Transfer Trip Schemes

The DISCO requires the IRR to install the necessary equipment and relays to establish disconnection from the Distribution Network automatically in case of Loss of Main Power (LoM) that may result in islanding the IRR with local load (Islanding).

As some forms of LoM protection might not readily achieve the required level of performance (e.g. under balanced load conditions), or that may result in excessive tripping of the IRR, the preferred method is by means of inter-tripping signals (Transfer Trip Schemes) from circuit breakers that operate in response to the Distribution System fault. Therefore Transfer Trip Schemes shall be installed where required by the DISCO.

In case of absence of a Transfer Trip Scheme, a G59 protection relay shall be installed at the PCC that is capable of disconnecting the system from the network in case of loss of main (LoM) power from the network and in synchronization with the DISCO's protection relays to prevent islanding of the IRR with local load.

The following Table 10-1 shows the proposed settings of the Loss of Main Power (LoM) Vector Shift relays as well as the rate of change of frequency (RoCoF) relays.

Table 10-1 – LoM Protection Settings – Vector Shift & RoCoF Relays Settings

Protection Function	Setting
LoM (Vector Shift)	K1 x 6 degrees
LoM (RoCoF) for Power Stations **less than 5 MW**	K2 x 0.125 Hz/s
LoM (RoCoF) for Power Stations **greater or equal to 5 MW**	1 Hz/s, time delay 0.5s

Where:
K1 = 1.0 (for low impedance networks) or 1.66 – 2.0 (for high impedance networks)
K2 = 1.0 (for low impedance networks) or 1.6 (for high impedance networks)

IRR-DCC-MV 11. System Impact Studies

All IRRs are required to complete a System Impact Study to show compliance with the requirements of IRR-DCC-MV where applicable. Refer to Appendix 1 for list of studies that must be performed, where this list shall be continuously updated and expanded by the DISCO's as needed.

The System Impact Studies shall be conducted either by the DISCO or an approved third party consultant, where the System Impact Study will be performed to show compliance with the requirements of IRR-DCC-MV where applicable. For Type C IRR, the studies shall be completed by NEPCO. The studies shall cover the following components:

Table 11-1– Study Requirements

Study	**Type A**	**Type B**	**Type C**
To be completed by NEPCO	Affected System	Affected System	ALL
Steady State Power Flow Study & Losses	ALL	ALL	
Short Circuit and Protection Study	ALL	ALL	
Voltage Flicker	ALL	ALL	
Harmonics	ALL	ALL	
Voltage Transient Stability Study	>5 MW	> 5 MW	
System Dynamic Response Study	>10 MW	>10 MW	