
MALAWI GRID CODE

MALAWI ENERGY REGULATORY AUTHORITY

Amendment 004 – January 2025

Changed Section 8 to include BESS

Renamed Section 8 to Unconventional to align with Section 7

Used the word facility to mean both RPP and BESS

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PART 1: GENERAL CONDITIONS

SECTION 1: BACKGROUND

1.1. INDUSTRY REFORM

1.1.1. The 2003 Energy Policy which was revised in 2018 indicates that Electricity Supply Industry (ESI) has to be liberalized and has been supported by the 2004 Energy Laws as amended in the 2016 Electricity Act.

1.1.2. The main features of the Policy on the Electricity Sector are:

- a) To facilitate the introduction of Independent Power Producers (IPPs); and
- b) To permit open and non-discriminatory access to the Transmission System; and

1.1.3. The Policy is implemented through various institutions and support mechanisms (instruments) including legislation and regulation.

1.2. INDUSTRY STRUCTURE

1.2.1. Before the power sector reform in January 2017, ESCOM was solely responsible for generation, transmission and distribution including exports to border towns of the neighbouring countries (Zambia and Mozambique).

1.2.2. The Energy Laws have allowed a third-party access. Currently, Independent Power Producers connected to the grid sell to the Single Buyer, the only authorized buyer of all power and energy within Malawi. The government or regulator may mandate equitable commercial and technical terms for the market. The figure 1.1 shows the industry structure after the establishment of IPPs.

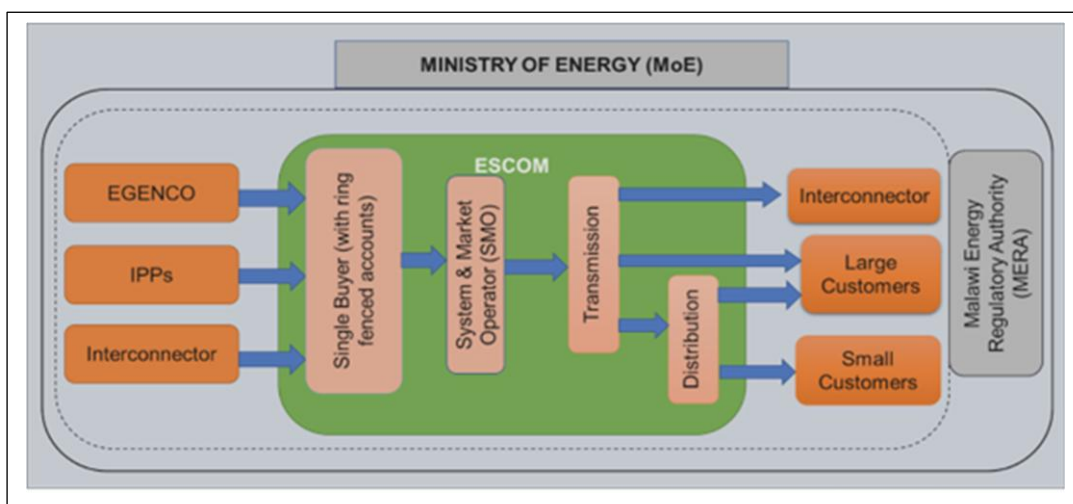


Figure 1.2-1: Electricity Supply structure in Malawi

1.2.3. Due to Malawi's unique geographic location, it is expected that the number of transmission inter-connectors could increase significantly over the medium to long term to support the tighter integration of the region's electricity grid. These inter-connectors could serve a dual purpose in that it can help Malawi to meet its growing demand for electricity.

1.2.4. The following elements of Malawi's Electricity Supply Industry (ESI) structure are relevant to the design and implementation of the Grid Code:

- a) Generation facilities owned by EGENCO- and other Independent Power Producers (Generation Licensees).

-
- b) Transmission network owned by the Transmission Licensee.
 - c) Distribution network owned by ESCOM (Distribution Licensee).
 - d) A System and Market Operator, responsible for dispatching generation and controlling the operation of the Malawi grid.
 - e) The Single Buyer responsible for long term power planning and purchasing bulk supply customers purchasing.

1.3. REGULATORY AUTHORITY

1.3.1. MERA has the responsibility to evaluate and issue any licence application. Subject to the provisions of the Energy Regulation Act, no person may carry on any undertaking unless he or she holds a valid licence. A separate licence is required for each of the following activities:

- a) the generation of electricity for sale
- b) the operation of transmission network
- c) the operation of a distribution network
- d) the importation of electricity into Malawi
- e) the export of electricity out of Malawi
- f) the operation of power system and market
- g) long-term planning and power purchase

SECTION 2: INTERPRETATION AND EFFECTIVENESS

2.1. DEFINITIONS

2.1.1. Capitalised words and expressions used in this Code, unless the context otherwise requires shall bear the following meaning:

- **Active Power:** The time average of the instantaneous power over one period of the electrical wave, measured in Watts (W) or multiples thereof. For AC circuits or Systems, it is the product of the root-mean-square (RMS) or effective value of the voltage and the RMS value of the in-phase component of the current. In a three-phase system, it is the sum of the Active Power of the individual phases
- **Amendment:** Any change, modification, insertion, or deletion of this Grid Code.
- **Ancillary Services:** Services supplied to the system by generators, distributors, or end-use customers necessary for the reliable and secure transport of power from generators to distributors and customers, i.e. to maintain the short-term reliability of the IPS. They include the various types of reserves, Black Start, constrained generation, etc.
- **Area Control Error:** The mismatch between the instantaneous demand and supply of a Control Area. It combines the frequency error and the tie line schedule error.
- **Automatic Generation Control:** The automatic centralised closed loop control of generating units by means of the computerised EMS of the System and Market Operator. Unit output is controlled by changing the set point on the governor.
- **Auxiliary Supply:** Supply of electricity to auxiliary systems of a Unit or substation equipment.
- **Black Start:** The provision of generating equipment that, following a total system collapse (black out), is able to:
 - a) Start without an outside electrical supply and
 - b) Energise a defined portion of the TS so that it can act as a start-up supply for other capacity to be synchronised as part of a process of re-energising the TS.
- **Bulk Supply Customer:** A consumer directly connected to the Transmission system.
- **Busbar:** An electrical conduit at a substation where lines, transformers and other equipment are connected.
- **Check Metering:** The metering and/or calculation process to determine metering data which will be used by the Metering Administrator, in Market Settlement process, as indicated in the Market Rules, for the purpose of checking and validating the measurements provided by the Main Metering, or to replace measured data in case of failure or malfunction of the Main Metering.
- **Co-generator:** A Unit that is part of a specific industrial or production process and is not connected to the TS.
- **Commercial Metering System:** The system to measure and send to the Metering Administrator the energy injected or withdrawn from the grid, or the maximum demand, by a Market Participant. This metering will be used for the Market Settlement process by the Metering Administrator.
- **Connection Point:** The site or point of connection between a Distributor, a Generator or a Bulk Supply Customer and the Transmission System where Customer's assets are physically connected to the Transmission Licensee's assets.
- **Constrained generation:** The difference between the energy scheduled at the Point of Connection of the generator under the unconstrained schedule, and the energy scheduled at the Point of Connection under the constrained schedule derived to accommodate TS constraints.

- **Control Area:** A subset of SAPP that adheres to the minimum requirements for a control area as defined in the SAPP Operating Guidelines. (South Africa, Malawi, Botswana, Mozambique, Swaziland and Lesotho currently operate as one control area. Eskom, South Africa, manages the control area and all control area services such as AGC are under their control.)
- **Control Centre:** An entity responsible for the operational control of electricity network assets.
- **Critical Loading:** The condition when the loading of transmission lines or substation equipment is between 90 percent and 100 percent of the continuous rating.
- **Data:** See Information
- **Data Register:** The equipment which receives, registers and stores the information received from the Meters, and serves as a link to the remote reading. Data registers could be incorporated into the Meters itself or constitute a separated piece of equipment.
- **Day:** A period of 24 consecutive hours commencing at 00:00 and ending at 24:00.
- **Distribution:** The conveyance of electricity through a distribution system, which consists wholly or mainly of medium and low voltage networks, to a customer
- **Distribution Licensee (Distributor):** A holder of a Distribution and Supply licence granted or deemed to be granted by the Authority under the Energy Regulation Act in accordance with Part II of the Electricity Act.
- **Distribution System:** An electricity network consisting of assets (including substations, transformers, cables, lines and associated equipment) which are operated at Medium Voltage and Low Voltage.
- **Distributor:** same meaning as Distribution Licensee.
- **Droop:** The percentage change in (design) speed required for 100% governor action
- **Embedded generator:** A Unit, other than a co-generator, that is not directly connected to the TS.
- **Emergency:** A situation where Transmission or distribution service-providers have an unplanned loss of facilities, or another situation beyond their control, that impairs or jeopardises their ability to supply their system demand.
- **Emergency outage:** An outage when plant has to be taken out of service so that repairs can immediately be affected to prevent further damage or loss.
- **End-use customer:** User of electricity connected to the TS.
- **Fast Start:** The capability of a Generating Unit or Generating Plant to start and synchronize with the TS within 15 minutes.
- **Firm supply:** A supply that enjoys a level of reliability as specified in the Network Code.
- **Flicker:** A cyclic voltage fluctuation, normally between 0, 1 Hz and 10 Hz, that causes optical stress to humans.
- **Forced outage:** Occurs when a component is taken out of service immediately either automatically or as soon as switching operations can be performed as a direct result of abnormal operating/emergency conditions or human error.
- **Frequency:** The number of oscillations per second on the AC waveform.
- **Generating Unit:** A device used to produce electrical energy.
- **Generator:** A legal entity operating a licenced Generating Unit or Power Station.
- **Governing:** A mode of operation where any change in system frequency beyond the allowable frequency dead band will have an immediate effect on the Unit output according to the governor droop characteristic.
- **Governor droop characteristic:** The MW/Hz characteristic according to which governing

will take place.

- **Grid Code:** A document (or set of documents) that legally establishes technical and other requirements for the connection to and use of an electrical system by parties other than the owning electric utility in a manner that will ensure reliable, efficient, and safe operation.
- **Grid Code Technical Committee:** A panel of stakeholder representatives tasked with review of the Grid Code amendments.
- **Grid Code Participant:** Any legal entity that falls under the mandate of the Grid Code and meets the criteria set out in this Code.
- **High Voltage:** A voltage exceeding 1000 volts (RMS) AC and above. In general sense, the set of voltage levels in excess of low voltage or in restrictive sense, the set of upper voltage levels used in power system for transmission of electricity $\geq 66\text{kV}$
- **Information:** Any type of knowledge that can be exchanged, always expressed (i.e. represented) by some type of data. Information is made into data to be stored and processed either electronically or otherwise.
- **Information Owner:** The party to whose system or installation the information pertains
- **Interconnected Power System:** The TS and any other connected system elements that are likely to have an impact on the electricity supply at a national level, e.g. Power Stations with a capacity of more than 500 kVA and networks linking such Power Stations to the TS.
- **Interruptible load:** Consumer load or a combination of consumer loads that can be contractually interrupted without notice or reduced by remote control or on instruction from the System and Market Operator. Individual contracts place limitations on usage.
- **Interruption of Supply:** An interruption of the flow of power to a Point of Supply not requested by the customer
- **Imbalance:** The mismatch between the energy scheduled at a Point of Supply or a generator Point of Connection and the actual energy metered at that Point of Supply or generator Point of Connection over a scheduled period.
- **Islanding:** The capability of generating units to settle down at nominal speed, supplying own auxiliary load after separation from the grid, at up to full load pre-trip conditions.
- **License (To be defined)**
- **Load reduction:** The ability to reduce customer demand by Load Curtailment and load shedding.
- **Low Voltage:** A voltage of 1000 volts (RMS) or less and also a set of voltage levels used for the distribution of electricity and whose upper limit is generally accepted to 1kV.
- **Losses:** The technical or resistive energy losses incurred on the TS.
- **Main Metering:** The metering process to determine metering data utilizing the Commercial Metering System which will be used by the Metering Administrator as a prime reference for the measurement of the maximum capacity and active or reactive energy interchanged at a Connection Point in Market Settlement process
- **Manual load shedding:** The load reduction obtained by manually shedding load at convenient points on the distribution system within 10 minutes of the instruction being issued by the System and Market Operator.
- **Market Participant:** As defined in the Market Rules
- **Market Rules:** A document of this name approved by MERA which set the rules and procedures for the operation of the market of the Electricity Sector of Malawi
- **Master Plan:** A plan developed by the Single Buyer, resulted for the joint optimization of the generation and TS of Malawi, covering at least 10 years which identifies the developments to be carried out in generation and the TS in order to supply the forecasted

demand with the prescribed levels of reliability and security.

- **Maximum Continuous Rating:** The capacity that a generating unit is rated to produce continuously under normal conditions.
- **Medium Voltage:** A voltage of more than 1000 volts (RMS) but not more than 44000 volts (RMS).
- **Meter:** The device that measures and registers the integral active Energy or Reactive Energy over a metering interval and/or the maximum capacity, as it corresponds, and may include a data recorder
- **Metering:** All the equipment employed in measuring the supply together with the apparatus directly associated with it.
- **Metering Administrator:** The entity, integrated into the SMO, responsible for the metering and settlement process of the Electricity Market of Malawi
- **Metering Installation:** An installation that is composed of an electronic meter that is remotely interrogated has an electronic communication link and is connected to the TMA's Metering database
- **Month:** A calendar month comprising a period commencing at 00:00 hours on the first day of that month and ending at 24:00 on the last day of that month;
 - Nominal Power Absorbed (P_{na}): The maximum active power output a BESS is designed to continuously absorb at the point of connection
 - Nominal Power Delivered (P_{nd}): The maximum active power output a BESS is designed to continuously deliver at the point of connection
- **Participant:** See Grid Code Participant
- **Party:** Any current or future Participant or the MERA.
- **Planned Interruption:** A Planned Outage that will interrupt customer supply.
- **Planned Outage:** An outage of equipment that is requested, negotiated, scheduled and confirmed a minimum of 14 days prior to the maintenance / repairs taking place.
- **Point of Common Coupling:** The electrical node, normally a Busbar, in a Transmission Substation where different feeds to customers are connected together for the first time.
- **Point of Delivery:** See Point of Supply.
- **Point of Supply:** Transmission substation where energy can be supplied to distributors and end-user.
- **Power Station:** One or more units at the same physical location
- **Power Quality Directive:** MERA directive for the management of power quality in the ESI.
- **Primary Response:** The automatic response of a Generating Unit to frequency changes, typically provided by the action of the speed governors of synchronous generators
- **Primary Reserve:** The amount of reserve provided by a Generating Units due to Primary Response, released increasingly from zero to [five] seconds from the time of frequency change.
- **Primary Substation Equipment:** High voltage equipment installed at substations
- **Protection:** The process of clearing a fault on the IPS in order to protect plant and people.
- **Quick Reserve:** Interruptible Load or capacity readily available which can be started and loaded within ten (10) minutes to meet the system demand. This includes hydro plant, gas turbines, pumped storage and Interruptible Load.
- **Quote:** A legal document given to a customer for the purpose of providing a price for one or more specified Transmission service(s)

- **Rate of Change of Frequency:** The rate at which frequency changes with respect to time, based on a 200ms time window of which average value is calculated
- **Reactive Power:** The component of electrical power representing the alternating exchange of stored energy (inductive or capacitive) between sources and loads or between two systems, measured in VAR or multiples thereof. For AC circuits or systems, it is the product of the RMS value of the voltage and the RMS value of the quadrature component of the alternating current. In a three-phase system, it is the sum of the Reactive Power of the individual phases.
- **Regulating Reserve:** Generation capacity (or customer loads) available to respond within 10 minutes. This reserve category reserves capacity as part of the regulation ancillary service. The purpose of this is to allow for enough capacity to control the frequency and Control Area tie-lines power within acceptable limits in real time.
- **Regulation and Load Following**
 - a) **Regulation** means the provision of generation and load response capability, including capacity, energy and manoeuvrability that responds to automatic control signals issued by the System and Market Operator.
 - b) **Load following** means the provision of generation and load response capability, including capacity, energy, and manoeuvrability, that is dispatched by System and Market Operator to match power generation and load demand within a scheduling period.
- **Risk-related Outage:** A Planned Outage where the next credible contingency would result in a loss of load, loss of supply, voltage slide, thermal overload or dynamic stability constraint.
- **SAPP Emergency Energy:** Additional energy supplied by other operating members (utilities) of SAPP for assistance during periods of shortage. Emergency energy is normally available only for periods of less than six hours and rates are in accordance with the SAPP operating guidelines. Purchasing of SAPP emergency energy is enforced by SAPP after ten minutes on failure to reschedule with other operating members during periods of shortages.
- **Scheduling:** A process to determine which unit or equipment will be in operation and at what loading
- **Security:** The probability of not having an unwanted operation.
- **Significant Incident:** An event that threatens the integrity of the Power System, affects the security of the TS or pose severe economic implications to the Users. A Significant Incident occurs when
 - a) More than 3 System Minutes of load was interrupted;
 - b) Severe damage to plant has occurred.
- **Single Buyer:** The entity responsible for buying electricity to generators, conclude agreements to import or export electricity, perform the expansion planning, and prepare the long term operation schedules
- **Speed of Operation:** The time taken to clear a fault on the IPS.
- **Spinning Reserve:** The unused capacity which is synchronized to the System, and which can be delivered immediately without manual intervention.
- **Stakeholders:** The entities affected by or having a material interest in the Grid Code. This includes customers and other industry Participants, for example the MERA, the Single Buyer and the SAPP.
- **State of Charge:** The degree to which BESS is charged expressed as a percentage of the charging capacity that can be stored
- **Substation:** A site where switching and/or transformation equipment is installed.
- **System and Market Administrator (SMO):** The institution responsible for operating the

system and administering the market, and holds the System and Market Operation licence granted or deemed to be granted by MERA under the Energy Regulation Act in accordance with [Part II of the Electricity Act];

- **System Frequency:** The frequency of the fundamental AC voltage as measured at selected points by the System and Market Operator. The scheduled (target) system frequency for the SAPP is 50 Hz.
- **System Minutes:** The normalised performance indicator for interruptions, defined as follows:

System Minutes interrupted = energy interrupted (MWh) * 60 / system peak demand (MW).

- **System and Market Operator:** The entity responsible for short-term reliability of the IPS, which is in charge of controlling and operating the TS and dispatching generation (or balancing the supply and demand) in real time. (A licensee responsible for operating the transmission system and the electricity market of Malawi – as defined in the electricity amendment act 2016)
- **Load Dispatch Centre:** The System and Market Operator shall be the Load Dispatch Centre.
- **Transmission:** The conveyance of electricity by means of a Transmission System, which consists wholly or mainly of high voltage networks and electrical plant, from an energy source or system to a customer.
- **Transmission Equipment:** The equipment that is needed for the purpose of Transmission.
- **Transmission Licensee (TL):** A holder of a Transmission licence for transmitting electricity granted or deemed to be granted by the Authority under the Energy Regulation Act in accordance with Part II of the Electricity Act;
- **Transmission System:** An electricity network consisting of assets (including substations, transformers, cables, lines and associated equipment) which are operated wholly or mainly at a High Voltage.
- **Unplanned Outage:** An outage that is not requested, negotiated, scheduled, and confirmed 14 days before taking place. This type of outage is not a forced outage, emergency outage or opportunity maintenance.
- **User:** Any legal person that connect directly to the Transmission System. Customer types may include Generators, Distributor(s), and Bulk Supply Customers.

2.2. ACRONYMS / ABBREVIATIONS

Note: Standard SI symbols and abbreviations are used throughout the Grid Code without re-definition here.

- **ABOM** : Agreement Between Operating Members (Of The SAPP)
- **AC** : Alternating Current
- **ACE** : Area Control Error
- **AGC** : Automatic Generation Control
- **ARC** : Auto Re-Close
- **AVR** : Automatic Voltage Regulator
- **CT** : Current Transformer
- **DC** : Direct Current
- **DLC** : Dead Line Charge
- **DPI** : Dip Proofing Inverter
- **EENS** : Expected Energy Not Served
- **E/F** : Earth Fault
- **EMT** : Electromagnetic Transient
- **FACTS** : Flexible AC Transmission System
- **F/L** : Fault Level
- **GCAC** : Grid Code Advisory Committee
- **GCR** : Grid Code Requirement
- **HV** : High Voltage
- **HVDC** : High Voltage Direct Current
- **Hz** : Hertz
- **IDMT** : Inverse Definite Minimum Time
- **IEC** : International Electro-technical Commission
- **IPD** : Independent Power Distributor
- **IPP** : Independent Power Producer
- **IPS** : Interconnected Power System
- **LFSM** : Limited Frequency Sensitivity Mode
- **MERA** : Malawi Energy Regulatory Authority
- **MCR** : Maximum Continuous Rating
- **MUT** : Multiple-Unit Tripping
- **MV** : Medium Voltage
- **MVA** : Megavolt-Ampere
- **MW** : Megawatt
- **OEM** : Original Equipment Manufacturer
- **O/C** : Over-Current
- **PCC** : Point of Common Coupling
- **PCLF** : Plant Capability Loss Factor

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- **POD** : Point of Delivery
 - **P.U** : Per Unit
 - **PPs** : Power Plants
 - **QOS** : Quality of Supply
 - **RMS** : Root Mean Square
 - **RoCoF** : Rate of Change of Frequency
 - **RTU** : Remote Terminal Unit
 - **SAPP** : Southern African Power Pool
 - **SB** : Single Buyer
 - **SCADA** : Supervisory Control and Data Acquisition
 - **SMO** : System and Market Operator
 - **SOC** : State of Charge
 - **SSR** : Sub-Synchronous Resonance
 - **SVC** : Static VAR Compensator
 - **TMA** : Transmission Metering Administrator
 - **TRFR** : Transformer
 - **TRV** : Transient Recovery Voltage
 - **TS** : Transmission System
 - **TSB** : Transmission Supply Business
 - **UAGS** : Unplanned Automatic Grid Separations
 - **UCLF** : Unit Capability Loss Factor U_m
 - **Vmax** : Maximum Rated Voltage
 - **Vn** : Nominal Voltage
 - **VT** : Voltage Transformer

2.3. NOTICES AND DOMICILE

- 2.3.1. Communication with the SMO in respect of the normal operations of this Grid Code shall be sent to the following chosen address:

**The Chief Executive Officer
Electricity Supply Corporation of Malawi
Box 2047
Blantyre**

ATT: Director of System and Market Operation

- 2.3.2. Communication with the secretariat (MERA) in respect of the normal operations of this Grid Code shall be sent to the following chosen address:

**The Chief Executive Officer
Malawi Energy Regulatory Authority
P/B B-496
Capital City
Lilongwe 3**

ATT: Director of Electricity and Renewable Energy

- 2.3.3. Communication with TRANSMISSION in respect of the normal operations of this Grid Code shall be sent to the following chosen address:

**The Chief Executive Officer
Electricity Supply Corporation of Malawi
Box 2047
Blantyre**

ATT: Director of Transmission

- 2.3.4. Any notice given in terms of this Grid Code shall be in writing and shall:
- a) if delivered by hand, be deemed to have been duly received by the addressee on the date of delivery and a receipt will have to be produced as proof of delivery.
 - b) if posted by pre-paid registered post, be deemed to have been received by the addressee 14 days after the date of such posting.
 - c) if successfully transmitted by facsimile or email, be deemed to have been received by the addressee one day after dispatch.
- 2.3.5. Notwithstanding anything to the contrary contained in this Grid Code, a written notice or communication received by one of the parties from another, including by way of facsimile transmission, shall be adequate written notice or communication to such Party.

This Grid Code, although uniquely Malawian, has drawn on regionally and internationally available Grid Codes and other documents where applicable.

The industry wishes to express its appreciation towards who has played a leading role in compiling the first draft of the Grid Code.

SECTION 3: GRID CODE TECHNICAL COMMITTEE

3.1. INTRODUCTION

- 3.1.1. This Section describes the provisions necessary for the overall administration and review of the various aspects of the Grid Code. This code shall be read in conjunction with the relevant legislation, licences issued to generators, transmission companies and distributors, and other operating codes that relate to the Electricity Supply Industry

3.2. ADMINISTRATIVE AUTHORITY

- 3.2.1. Malawi Energy Regulatory Authority Board (MERA) is the administrative authority for the Grid Code.
- 3.2.2. MERA shall ensure that the Grid Code is compiled, approved, and implemented for the benefit of the industry.
- 3.2.3. The Grid Code Secretariat will be responsible for the implementation, maintenance, and revision control, and ensure all recipients have the latest version and acknowledged the receipt of codes.
- 3.2.4. The Grid Code Secretariat shall also ensure that they have in their custody the latest copies of relevant standards quoted in the Malawi Grid Code.

3.3. THE GRID CODE TECHNICAL COMMITTEE (GCTC)

- 3.3.1. MERA shall constitute the GCTC every three years. The GCTC shall have the following functions
- a) Ensure a consultative stakeholder process is followed in the formulation and review of the Grid Code.
 - b) Review and make recommendations regarding proposals to amend the Grid Code.
 - c) Review and make recommendations regarding proposals for exemption to comply with the Grid Code.
 - d) Facilitate the provision of expert technical advice to MERA on matters related to the Grid Code; and
 - e) Attend to the resolution of Non-Conformance Report incidences

3.4. COMPOSITION OF THE GCTC

- 3.4.1. The GCTC shall be composed of representatives of all stakeholders of the Electricity Supply industry (ESI) in Malawi as follows:
- a) One member representing the System and Market Operator (SMO) who will chair the GCTC;
 - b) One member representing Transmission Licensee (TL);
 - c) Three members representing Generation Licensees (GL) one of which from EGENCO;
 - d) Two members representing the Distribution Licensee (DL);
 - e) One member representing MERA who will be the secretary of the GCTC with no voting rights.
- 3.4.2. The members shall be identified as follows:

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- a) If an industry association represents the larger part of the constituency, the association will be requested to make the nomination(s);
 - b) If the constituency consists of more than one association and/or a relatively small number of entities, calls for nominations will be sent to all entities. MERA may decide on the member if more than the required number of nominations is received. MERA may choose the member if no nominations are received; and
 - c) If there is no identifiable entity, a public call for nomination will be sent out by MERA. MERA may decide on the member if more than the required number of nominations is received

3.4.3. MERA shall publish changes in membership within 14 days on the MERA website.

3.4.4. GCTC members shall serve a three-year term, after which they shall be eligible for re-appointment. MERA may request the replacement of members by their constituency upon recommendation of the GCTC, if they have not attended three consecutive meetings; and

3.4.5. Members shall nominate an alternative representative. Such nomination shall be made in writing to the Secretariat.

3.5. FUNCTIONING OF THE GCTC

3.5.1. The GCTC Chairman may propose to MERA:

- a) To accept or review a GC amendment proposal that has been presented to the GCTC;
- b) Amendments to correct, complete or improve the Grid Code and, eventually, the Market Rules; and
- c) New or updated Procedures for implementation of the Grid Code.

3.5.2. The GCTC shall schedule at least two annual review sessions. The format of a session may be determined by the GCTC but should include a work session if proposed changes are of a substantive nature. Agenda items shall be circulated at least 14 days in advance of the review session;

3.5.3. The GCTC shall determine its own meeting procedures and code of conduct subject to the constitutional provisions set out in this section. These procedures and code of conduct shall be published on MERA website;

3.5.4. SMO member shall chair the GCTC meetings. When SMO member or alternate is unable to attend the GCTC meeting, s/he shall make arrangements for an alternative chairperson for the duration of the meeting.

3.5.5. A quorum shall consist of 50% of members plus one member of the GCTC. Decisions by the GCTC shall be taken by means of a majority vote of the duly constituted GCTC. If votes are even, then the Chairperson shall have the deciding vote;

3.5.6. Alternate members shall be allowed to vote only when the main member is not available for voting;

3.5.7. If a quorum is not present within 30 minutes of the stipulated starting time of the meeting, provided the Secretariat gave proper notice, the meeting shall make the necessary recommendation and the Secretariat shall circulate this electronically to all GCTC members for decision within five work days, such decisions to be returned to the Secretariat. Such decisions shall be immediately effective if voted on by a quorum. These decisions shall be minuted and confirmed at the next GCTC meeting where a quorum is present;

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- 3.5.8. Decisions of the GCTC shall be recorded together with dissenting views expressed by GCTC members;
 - 3.5.9. MERA shall fund the administrative activities of the GCTC. Members shall be responsible for their own travel and subsistence expenditure.
 - 3.5.10. The GCTC may co-opt experts with the purpose of allowing expert opinion to be obtained regarding complicated submissions.
 - 3.5.11. Industry participation and consultation shall be encouraged in, and obtained through, the activities of these experts. The GCTC shall provide the experts with a full scope of work and an urgency indicator for each task referred to them; and
 - 3.5.12. MERA shall publish the Grid Code and amendments after the approval. MERA shall also publish the Grid Code on its website.

3.6. THE GRID CODE SECRETARIAT

- 3.6.1. The Secretariat shall perform the following functions:
 - a) Ensure procedures are developed and published for the review of proposed amendments and exemptions by the GCTC;
 - b) Provide standard submission forms to participants,
 - c) Assist, when requested, in the preparation of submissions to the GCTC;
 - d) Prepare amendment and exemption proposals for submission to MERA board following review by the GCTC;
 - e) Manage Grid Code documentation;
 - f) Disseminate relevant information;
 - g) Inform participants of the progress with applications for amendment or exemption;
 - h) Co-ordinate the activities of the GCTC;
 - i) Keep and circulate minutes of meetings and documentation of proceedings of the GCTC ;and
 - j) Function as a formal communication channel for the GCTC.
- 3.6.2. The Secretariat shall make the latest version of the Grid Code available electronically and notify all Participants of approved amendments or exemptions within one week of receipt of approval by the Minister responsible for Energy.
- 3.6.3. The Secretariat shall make hard copies of the latest version of the Grid Code available to requesting entities, for which a nominal fee may be charged to recover reproduction costs.

3.7. GRID CODE PARTICIPANTS

- 3.7.1. The following licensed entities shall be Grid Code participants:
 - a) Generating Companies with power stations where the total installed or planned capacity is greater than 10 MVA;
 - b) Generating Companies with power stations connected or planning to connect to the transmission system (TS);
 - c) Generating Companies embedded or planning to embed in any distribution system that is connected to the TS

- d) The Distributor(s) connected or planning to connect to Distributors to any TS;
- e) Transmission Licensee or prospective Transmission Licensee
- f) The System and Market Operator; and
- g) The Single Buyer

3.7.2. No entity shall have access to the IPS without being registered as a Grid Code participant.

3.7.3. Network Service providers shall ensure that customers who meet criteria are registered as participants before accessing licensed services.

3.8. REGISTRATION PROCEDURE

3.8.1. The Secretariat shall be responsible for the registration of participants.

3.8.2. Participants shall be registered in different categories: generator, distributor, transmission licensee, System and Market Operator and Single Buyer

3.8.3. All entities listed in section 3.7.1 shall apply for registration with the Secretariat as a participant.

3.9. REQUESTS FOR REVIEW OR AMENDMENT OF GRID CODE

3.9.1. The SMO, a Participant, or any other interested person may file a written submission (the "Amendment Submission") to the GCTC, at such address as may be published by the GCTC from time to time, to propose one or more Amendments to this Grid Code or to identify any provision of this Grid Code in respect of which it is considered that an Amendment or review may be necessary or desirable. The Amendment Submission shall include a statement of the reasons for which an Amendment to or review of the GC may be necessary or desirable. The GCTC may request that the person submitting the Amendment Submission provide further particulars with respect to the Amendment Submission.

3.9.2. The GCTC shall provide to MERA a copy of any Amendment Submission received.

3.9.3. The GCTC shall give written notice to the person who made an Amendment Submission as to whether the proposed Amendment or the request for consideration of an Amendment or review is, in the opinion of the GCTC:

- a) of such a nature that consideration of the Amendment Submission is warranted; or
- b) of such a nature that no consideration of the Amendment Submission is warranted.

3.9.4. Where the GCTC gives notice under Rule 3.9.3.b), it shall notify MERA in writing of its opinion that no consideration of the Amendment Submission is warranted.

3.9.5. Where the GCTC decides pursuant to Rule 3.9.3.a) to proceed with the request, it shall Publish and give notice to all Participants of the particulars of the Amendment Submission and may also give notice to the person who made the Amendment Submission and to all the Participants of any comments which the GCTC may wish to make in respect of the Amendment Submission. The notice shall invite Participants and other interested persons to make, within such reasonable period as shall be specified in the notice, written submissions to the GCTC concerning the Amendment Submission.

3.9.6. The GCTC may, where it considers necessary or desirable, schedule and hold meetings with the person who made the Amendment Submission, Participants and other interested persons who filed a written submission.

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- 3.9.7. The GCTC shall, as soon as reasonably practicable following any meetings and consultations which may have been held, convene on one or more occasions as may be necessary to consider and vote on the Amendment Submission. The GCTC shall consider all submissions received within the time specified by the GCTC.
- 3.9.8. Following the conclusion of the deliberations if the GCTC considers the Amendment to be made, the GCTC shall submit a written report to MERA setting out:
- a) The recommendations of the GCTC and the reasons for its recommendations;
 - b) Where the recommendations of the GCTC include a proposal to amend the Grid Code, a copy of the proposed text of the Amendment, the suggested time of commencement of the Amendment, the recommendations of the GCTC, and a summary of any objections to the proposed Amendment which may have been contained in the submissions received or brought to the attention of the GCTC during any meetings held pursuant to 3.9.7;
 - c) A summary of the procedure followed by the GCTC in considering the matter;
 - d) A record of the vote of each member of the GCTC in respect of each of the recommendations made in the report; and
 - e) A summary of any objections raised by any member of the GCTC to the recommendations if such objecting member so requests.
- 3.9.9. The GCTC shall Publish the recommendations contained in the report referred to in Rule 3.9.8 and shall give notice thereof to all Participants and to the person who made an Amendment Submission to which the recommendations relate.
- 3.9.10. As soon as reasonably practicable following receipt of the report of the GCTC referred to in Clause 3.9.9, MERA may:
- a) Confirm the Amendment to the Grid Code, proposed by the GCTC;
 - b) Refuse to accept the Amendment for one or more reasons set out in Rule 3.9.11 and refer the decision back to the GCTC for additional review. MERA may suggest an alternative amendment to the Amendment proposed by the GCTC.
- 3.9.11. Where an Amendment is submitted to MERA pursuant to Rule 3.9.118 for its approval, MERA may reject the proposed Amendment if, in its opinion, the proposed Amendment:
- a) Unfairly discriminates against a Participant or class of Participants;
 - b) Will limit, and not advance, competition, or prevent free entry into the electricity market;
 - c) May allow one or more Participants to possess market power;
 - d) May have a potential for abuse of market power by one or more Participants;
 - e) Is not conducive to efficient operation of the IPS; or
 - f) Is not consistent with the Applicable Law or policy direction of the Ministry of Energy.
- 3.9.12. Subject to Rule 3.9.11 and to the terms of any order issued by MERA pursuant to this Grid Code, an Amendment to the Grid Code shall come into force on the date specified in the order of MERA confirming the Amendment, which date shall not be less than 30 days following the date of publication of the Amendment.
- 3.9.13. Where MERA:
- a) confirms the recommendation to amend the Grid Code, the SMO shall publish such decision on its website, together with a copy of the Amendment, and shall give notice of the decision to all Participants, the person who made the Amendment Submission to

which the decision relates and any persons who made submissions. The SMO will prepare and publish in its website the amended version of the Grid Code.

- b) Rejects the adoption of an Amendment to the Grid Code, the SMO shall publish such decision on its website and shall give notice of the decision to all Participants and to any person who made an Amendment Submission to which the decision relates.

3.10. GRID CODE EXEMPTION PROCEDURES

3.10.1. Any participant can apply for an exemption. Exemption from complying with provisions of the Grid Code may be granted by the MERA for the following reasons:

- a) To provide for existing equipment that has not been designed with consideration for the provisions of the Grid Code,
- b) To facilitate transition through interim arrangements and
- c) To facilitate temporary conditions necessitating exemption.

3.10.2. Appendix 1 shall contain a list of exemptions that have been approved, with the relevant expiry date. The reference number shall refer to the applicable paragraph in the Grid Code.

3.10.3. The GCTC shall draft procedures for recommending MERA granting exemptions for complying with provisions of the Grid Code.

SECTION 4: DISPUTE MEDIATION, RESOLUTION AND APPEAL MECHANISM

4.1. COMPLAINTS ABOUT THE OPERATIONS OF THE SECRETARIAT OR THE GCTC

- 4.1.1. Any complaint regarding the operations of the GCTC shall firstly be addressed in writing to the Secretariat. The GCTC shall attend to such complaints at or before the next session;
- 4.1.2. If the complaint is not resolved, the matter shall be referred to MERA as a dispute as described in Sub-Section 4.2.

4.2. COMPLAINTS BETWEEN / AMONG USERS, TL, SMO OR SB

- 4.2.1. The procedure for handling complaints shall include the incident report and non-conformance report requirements as described in clauses 4.2.3 and 4.2.4.
- 4.2.2. MERA shall develop a database of disputes resolved to assist in the resolution of future disputes. Where the outcome of a dispute resolution proceeding would require or imply an amendment to the Grid Code, MERA shall first consult with the GCTC.
- 4.2.3. Incident Report (IR)
 - a) An incident report should be seen as a formal communication of a problem.
 - b) A User may issue an incident report on becoming aware of a problem or a possible breach of the Grid Code. The TL, SMO or SB, as it corresponds, shall provide a reasonable explanation and, if appropriate, indicate what action it will take to address the problem.
 - c) The TL, SMO or SB may issue an incident report to a User, where the User is suspected of not complying with the necessary Grid Code requirements. The User shall provide the TL, SMO or SB, as it corresponds with a reasonable explanation and, where appropriate, indicate the measures that will be taken to address the problem.
 - d) TL, SMO or SB, as it corresponds, shall keep a log of all incident reports received and a log of all incident reports communicated to Users.
 - e) Incident reports are operational in nature and generally require action only by technical and User relations staff.
- 4.2.4. Non-conformance report (NCR)
 - a) A User may issue a non-conformance report when it is suspected that:
 - a.1) the TL, SMO or SB, as it corresponds, has failed to provide a reasonable explanation;
 - a.2) the TL, SMO or SB, as it corresponds, has wilfully misrepresented the facts concerning an incident;
 - a.3) the TL, SMO or SB, as it corresponds, has failed to implement the agreed preventative actions within the agreed time frame;
 - a.4) the number of Incident Reports is excessive in relation to historical performance; or
 - a.5) the actions/undertakings arising from a mediation or arbitration process have not been performed/adhered to
 - b) The TL, SMO or SB, as it corresponds, may issue a non-conformance report when it is suspected that:
 - b.1) the User has failed to provide a reasonable explanation;
 - b.2) the User has wilfully misrepresented the facts concerning an incident;

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- b.3) the User has failed to implement the agreed preventative actions within the agreed time frame;
 - b.4) the number of incident reports is excessive in relation to historical performance; or
 - b.5) the actions/undertakings arising from a mediation or arbitration process have not been performed/adhered to.
 - c) Non-conformance reports are indications of problems that require managerial intervention by the TL, SMO or SB, as it corresponds, or the User.
 - d) In the case where the parties agree with the NCR, recommended action shall be agreed upon. Both participants shall implement these recommendations within an agreed time frame.
- 4.2.5. TL, SMO or SB, as it corresponds, shall report annually to MERA on the following aspects of the procedure:
- a) Number of NCRs for each User category,
 - b) Number of closed out NCRs for each User category and
 - c) Number of disputes resolved.
- 4.2.6. A dispute may be declared when parties cannot agree on the NCR or the recommendations of the NCR or when the agreed recommendations are not implemented in the agreed time frame.

4.3. SUBMISSION OF DISPUTES TO MERA

- 4.3.1. Disputes are unresolved complaints between parties that require intervention. Any party may submit a dispute to MERA provided the required process of either 4.1 or 4.2 has been followed.
- 4.3.2. When a dispute is raised with MERA, parties shall provide the following information:
- a) Full history of relevant incident reports,
 - b) Detailed NCR and accompanying information that gave rise to the dispute and
 - c) Written report from each participants detailing the reason for not being able to close out the NCR
- 4.3.3. When a dispute that has not followed the relevant procedure reaches MERA, MERA shall generally refer the party to the correct process.
- 4.3.4. MERA shall act as the mediator to the dispute in accordance with powers and functions of the Authority in Energy Regulation section 9 (i) and MERA Dispute Mediation Procedural Rules. procedures stipulated in Energy Regulation Bylaws of 2009
- 4.3.5. Should the dispute mediation process succeed, the parties shall strive to honour their respective undertakings/actions agreed upon to the best of their abilities.
- 4.3.6. If mediation by MERA fails to provide the parties with an agreed solution, the parties shall refer the matter for arbitration for final decision
- 4.3.7. There shall be one arbitrator appointed according in accordance with the Energy Regulation Bylaws of 2009

4.3.8. The appointment of the arbitrator shall be agreed between the parties, but failing agreement between them within a period of 14 days after the arbitration has been demanded, either of the parties shall be entitled to request MERA to make the appointment and, in making its appointment, to have regard to the nature of the dispute. The following shall be considered, amongst other things, during the arbitration process:

- a) Existing and historical performance trends or practices;
- b) Reference standards;
- c) Appropriate network design or operation standards;
- d) Precedents with similar events;
- e) Historical agreements between the participants; and
- f) Total cost impact.

4.3.9. The ruling of the arbiter shall include a time frame for implementation and shall be final and binding on the parties

4.4. COMPLIANCE

4.4.1. All parties shall comply with the Grid Code as updated from time to time.

4.4.2. Participants shall inform MERA of any non-conformance report of a material nature that has been submitted to another Participant.

4.4.3. MERA may require a Participant to provide information deemed necessary for the proper administration of the Grid Code. This information shall, upon request, be treated as confidential.

4.4.4. Upon a report or suspicion of non-compliance MERA may seek to:

- a) resolve the issue through negotiation;
- b) take action in terms of the procedures for handling licensing contraventions; or
- c) consider an application for amendment or consider an application for exemption.

4.4.5. Users may apply for exemption from changes to the Grid Code under Sub-Section 3.10

4.5. CODE AUDITS

4.5.1. A User may request from the TL, SMO or SB, as it corresponds, or the TL, SMO or SB, as it corresponds, may request from a User, any material in the possession or control of that User relating to compliance with a section of the Grid Code. The requesting User may not request such information in relation to a particular section of the Grid Code within six months of a previous request made under this clause in relation to the relevant section.

4.5.2. A request under clause 4.5.1 shall include the following information:

- a) nature of the request,
- b) name of the representative appointed by the requesting participant to conduct the investigation and
- c) the time or times at which the information is required

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- 4.5.3. The relevant Participant may not unreasonably withhold any relevant information requested. It shall provide a representative of the requesting participant with such access to all relevant documentation, data and records (including computer records or systems) as is reasonably requested. This information shall be treated as confidential if requested. Any request or investigation shall be conducted without undue disruption to the business of the participant;
- 4.5.4. The cost of such audits will be borne by the complainant if the audit reveals compliance and by the Participant being audited if the audit reveals non-compliance.

4.6. APPENDICES

4.6.1. Appendix 1: Grid Code Amendment Request Form

GC A No:.....

Text to be amended: Section(s)..... Page(s)..... Change from (if additional space is required, please use attachments)

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to (if additional space is required, please use attachments)

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Reason for change(s)

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Change Initiated by..... Date Checked by:
(*Secretariat*) Date

Approved/Not approved:
(*GCTC CHAIRPERSON*)Date

4.6.2. Appendix 2: Grid Code Exemption Request Form

GC E No:.....

Text to be exempted from: Section(s)..... Page(s)..... Reason for exemption (if additional space is required, please use attachments)

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Additional *Information* (if additional space is required, please use attachments)

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Duration: From:.....To:.....

Exemption Applicant's Name:.....

Date Checked by:
(*Secretariat*) Date

Recommended by:
(*GCTC Chairperson*) Date

Approved/Not approved:
(*MERA BOARD CHAIRPERSON*).....Date

PART 2: NETWORK CODE

SECTION 5: PERFORMANCE REQUIREMENTS FOR THE TRANSMISSION SYSTEM

5.1. POWER QUALITY REQUIREMENTS

5.1.1. Power Quality Problems

- a) A Power Quality problem exists when at least one of the following conditions is present and significantly affects the normal operation of the Power System:
 - a.1) The Power System Frequency has deviated from the nominal value of 50 Hz;
 - a.2) Voltage magnitudes are outside their allowable range of variation;
 - a.3) Harmonic Voltage Distortions are outside the allowable limits within the Power System;
 - a.4) There is unbalance in the magnitude of the phase voltages outside the allowable limits; or
 - a.5) Voltage fluctuations cause Flicker that is outside the allowable Flicker Severity limits.

5.1.2. Frequency Variations

- a) The nominal fundamental frequency shall be 50 Hz.
- b) The control of system Frequency shall be the responsibility of the System and Market Operator. The System and Market Operator shall make its best endeavours to maintain the frequency of the system as close as possible to its nominal value and, in any case, within the limits of [49.5 Hz and 50.5] Hz during normal conditions. The System and Market Operator shall utilize for such purpose the Spinning and Regulation Reserves and it shall directly intervene whenever mentioned limits are breached.

5.1.3. Voltage Variations

- a) Voltage Variation is defined as the deviation of the root-mean-square (RMS) value of the voltage from its nominal value, expressed in percent.
- b) The Transmission Licensee and the System and Market Operator shall make its best endeavours to maintain Voltage Variations at any Connection Point during normal conditions within the limits indicated in following **Table 5-1-1** and **Table 5-1-2**

Table 5.1-1: Technical and Statutory Voltage Limits

Nominal continuous operating voltage on any bus for which equipment is designed	V_n
Maximum continuous voltage on any bus for which equipment is designed. Note: To ensure voltages never exceed V_m , the highest voltage used at sending-end busbars in planning studies should not exceed $0.98V_m$	V_m
Minimum voltage on Point of Common Coupling (PCC) during motor starting	$0.85V_n$

Maximum voltage change when switching lines, capacitors, reactors, etc.:	
Maximum Fault Level	0.03V _n
Minimum Fault Level	0.075 V _n
Statutory voltage change on bus supplying <i>customer</i> for any period longer than 10 consecutive minutes (unless otherwise agreed in Supply Agreement)	0.10 V _n ±10%V _n

Table 5.1-2: Acceptable Voltage Levels

V _n [kV]	V _m (kV)	(V _m - V _n V _n)%
765	800	4,58
400	420	5,00
330	346.5	5,00
275	300	9,09
220	245	11,36
132	145	9,85
66	72,5	9,85
33	36	9,09
11	12	9,09

5.1.4. Harmonics

- a) The Total Harmonic Distortion of the voltage at any Connection Point shall not exceed the limits given in Tables 5-1-3.

Table 5.1-3: Maximum Harmonic Voltage Distortion Factors

Voltage Level	THD	Individual	
		Odd	Even
220 kV and above	1.5%	1.0%	0.5%
132 kV-220 kV	2.5%	1.5%	1.0%
66 kV and below	3.0%	2.0%	1.0%

5.1.5. Voltage Unbalance

- a) Negative Sequence Unbalance Factor shall be defined as the ratio of the magnitude of the negative sequence component of the voltages to the magnitude of the positive sequence component of the voltages, expressed in percent. Zero Sequence Unbalance Factor shall be defined as the ratio of the magnitude of the zero-sequence component of the voltages to the magnitude of the positive sequence component of the voltages, expressed in percent.
- b) The maximum Negative Sequence Unbalance Factor at the Connection Point of any User shall not exceed one percent (1%) during normal operating conditions.
- c) The maximum Zero Sequence Unbalance Factor at the Connection Point of any User shall not exceed one (1) percent during normal operating conditions.

5.1.6. Flicker Severity

- a) The Flicker Severity at any Connection Point in the Grid shall not exceed the values given in Table 5-1-4.

Table 5.1-4: Maximum Flicker Severity

	Short Term	Long term
132 kV and above	0.8 unit	0.6 unit
Below 115 kV	1.0 unit	0.8 unit

5.2. RELIABILITY REQUIREMENTS

5.2.1. Criteria for Establishing Transmission Reliability Requirements

- a) The Reliability Standard MS 1891-1:2022 shall prescribe a uniform system of recording and reporting of TS reliability performance. This performance shall be measured through a set of selected Reliability Indices prescribed by MERA covering;
- a.1) the overall performance of the Transmission System.
 - a.2) the performance of specific equipment; and
 - a.3) the performance at connection points.
- b) The Transmission System shall be evaluated annually to compare its actual performance with the targets. For this purpose, the Transmission Licensee shall submit to MERA, yearly, a report evaluating past year reliability performance, major deficiencies observed and proposing actions to improve this performance.

5.2.2. Inclusions and Exclusions of Interruption Events

- a) A power Interruption shall include any Outage in the TS which may be due to the tripping action of protective devices during faults or the failure of transmission lines and/or power transformers, and which results in the loss of service to a TS User or a group of Users.
- b) The following events shall be excluded in the calculation of the reliability indices:
- b.1) Outages that occur outside the TS.
 - b.2) Outages due to Load shedding as a result of generation deficiency, instructed by the Market and System and Market Operator.
 - b.3) Planned Outages where the Users have been notified at least seven (7) days prior to the loss of power.
 - b.4) Outages that are initiated by the System and Market Operator during the occurrence of Significant Incidents or the failure of its facilities.
 - b.5) Outages caused by any natural or manmade calamities; and
 - b.6) Outages due to other events that the MERA shall approve after due notice and hearing.

5.2.3. The Transmission Licensee shall submit every three (3) months to MERA, an Interruption Report for the TS using the standard format prescribed by MERA.

5.2.4. Failure to report on performance requirements shall be treated in accordance with its licensing conditions.

SECTION 6: PROCEDURES FOR CONNECTION TO THE TRANSMISSION SYSTEM

6.1. PURPOSE AND SCOPE

6.1.1. This Section establishes a set of connection conditions for Generators, Distribution Licensees and Bulk Supply Customers to the Transmission System. In particular:

- a) To specify the technical, design, and operational criteria at the User's Connection Point;
- b) To ensure that the basic rules for connection to the Transmission System are fair and non-discriminatory for all Users of the same category; and
- c) To list and collate the data required by the Transmission Licensee from each category of User and to list the data to be provided by the Transmission Licensee to each category of User.

6.1.2. This Part applies to the following entities:

- a) The Transmission Licensee;
- b) The System and Market Operator;
- c) Generators;
- d) The Distribution Licensee(s); and
- e) Bulk Supply Customers.

6.2. TIME TO CONNECT

6.2.1. The agreed time period for connecting Users or upgrading connections shall be agreed between the Transmission Licensee and the User in every instance.

6.2.2. Applications for new or revised connections shall be lodged with the Transmission Licensee.

6.3. CONNECTION AGREEMENT

6.3.1. Any User seeking a new connection to the Transmission System shall secure the required Connection Agreement with the Transmission Licensee prior to the actual connection to the Transmission Network.

6.3.2. Any User seeking a modification of an existing connection to the Transmission System shall secure the required Amended Connection Agreement with the Transmission Licensee prior to the actual modification of the existing connection to the Transmission System.

6.3.3. The Connection Agreement or Amended Connection Agreement shall include provisions for the submission of information and reports, Safety Rules, Test and Commissioning programs, Electrical Diagrams, statement of readiness to connect, certificate of approval to connect, and other requirements prescribed by MERA.

6.4. SYSTEM IMPACT STUDIES

6.4.1. The Transmission Licensee shall develop and maintain a set of required technical planning studies for evaluating the impact on the Transmission System of any proposed connection or modification to an existing connection. These planning studies shall be completed within the period prescribed by the Transmission Connection Agreement.

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- 6.4.2. The Transmission Licensee shall specify which of the planning studies will be carried out to evaluate the impact of the proposed User's connection on the Transmission System.
 - 6.4.3. Technical and planning studies shall be conducted also in case of connection of Large Generators, even if they connect to the Distribution System (Large Embedded Generators) or inside the User's system. The Distribution Licensee shall collaborate with the Transmission Licensee in the development of studies involving Large Embedded Generators.
 - 6.4.4. Any User applying for connection or a modification of an existing connection to the Transmission System shall take all necessary measures to ensure that the proposed User Development will not result in the degradation of the Transmission System. The Transmission Licensee may disapprove an application for connection or a modification to an existing connection, if the System Impact Studies show that the proposed User Development will result in the degradation of the Transmission System performance.
 - 6.4.5. To enable the Transmission Licensee to carry out the necessary detailed System Impact Studies, the User may be required to provide some or all of the Detailed Planning Data listed in Part 6: Information Exchange Code.

6.5. APPLICATION FOR CONNECTION OR MODIFICATION

- 6.5.1. The Transmission Licensee shall establish the procedures for the processing of applications for connection or modification of an existing connection to the Transmission System.
- 6.5.2. The User shall submit to the Transmission Licensee the completed application form for connection or modification of an existing connection to the Transmission System. The application form shall include the following information:
 - a) A description of the proposed connection or modification to an existing connection, which shall comprise the User Development at the Connection Point;
 - b) The relevant planning data indicated in Part 6: Information Exchange Code; and
 - c) The Completion Date of the proposed User Development.

6.6. PROCESSING OF APPLICATION

- 6.6.1. The Transmission Licensee shall process the application for connection or modification to an existing connection within [30 days] from the submission of the completed application form.
- 6.6.2. After evaluating the application submitted by the User, the Transmission Licensee shall inform the User whether the proposed User Development is acceptable or not.
- 6.6.3. If the application of the User is acceptable, the Transmission Licensee shall provide quotations for the new connection or for upgrading existing connection, as the case may be, according to an approved MERA Tariff Methodology and within time frames agreed with prospective Users.
- 6.6.4. If the application of the User is not acceptable, the Transmission Licence shall notify the User why its application is not acceptable. The Transmission Licensee shall include in its notification a proposal on how the User's application will be acceptable.

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- 6.6.5. The User shall accept the proposal of the Transmission Licensee within [30 days], or a longer period specified in the Transmission Licensee's proposal, after which the proposal automatically lapses.
 - 6.6.6. The acceptance by the User of the Transmission Licensee's proposal shall lead to the signing of a Connection Agreement or an Amended Connection Agreement.
 - 6.6.7. If the Transmission Licensee and the User cannot reach agreement on the proposed connection or modification to an existing connection, the Transmission Licensee or the User may bring the matter before the MERA for resolution.

6.7. SUBMITTALS PRIOR TO THE COMMISSIONING DATE

- 6.7.1. The following shall be submitted by the User prior to the commissioning date, pursuant to the terms and conditions and schedules specified in the Connection Agreement:
 - a) Specifications of major equipment not included in the Standard Planning Data and Detailed Planning Data;
 - b) Details of the protection arrangements and settings referred to in Sub Section 7.6 for Generating Units and in Section 9.3 for Distribution Licensees and other Grid Users;
 - c) Electrical Diagrams of the User's Equipment at the Connection Point;
 - d) Information that will enable the Transmission Licensee to prepare the Connection Agreement;
 - e) Proposed Maintenance Program; and
 - f) Test and Commissioning procedures for the Connection Point and the User Development.

6.8. COMMISSIONING OF EQUIPMENT AND PHYSICAL CONNECTION TO THE GRID

- 6.8.1. Upon completion of the User Development, including work at the Connection Point, the Equipment at the Connection Point and the User Development shall be subjected to the Test and Commissioning procedures specified in Section 7.17.
- 6.8.2. The User shall then submit to the Transmission Licensee a statement of readiness to connect, which shall include the Test and Commissioning reports.
- 6.8.3. Upon acceptance of the User's statement of readiness to connect, the Transmission Licensee shall, within 15 days, issue a certificate of approval to connect.
- 6.8.4. The physical connection to the Transmission System shall be made only after the certificate of approval to connect has been issued by the Transmission Licensee to the User.

SECTION 7: TECHNICAL REQUIREMENT FOR CONNECTION OF CONVENTIONAL GENERATORS

7.1. OBJECTIVE

- 7.1.1. This Section specifies connection minimum acceptable technical, design and operational criteria which must be complied with by any Conventional Generator connected to or seeking connection to the Transmission System or by any Large Embedded Conventional Generators or Co-generators.
- 7.1.2. The objective of the connection conditions is to ensure that by specifying minimum technical, design and operational criteria, the basic rules for connection to the Transmission System are similar for all Generators of similar characteristics and will enable the Transmission Licensee and System and Market Operator to comply with its statutory and licence obligations. Since quality of supply and grid integrity are shared responsibilities between the Transmission Licensee, System and Market Operator and Users, these conditions furthermore ensure adherence to sound engineering practice and codes by all the Conventional Generators.
- 7.1.3. This Part applies to the following entities:
- a) The Transmission Licensee;
 - b) The System and Market Operator; and
 - c) Generators.

7.2. VOLTAGE AND FREQUENCY WITHSTAND CAPABILITY

- 7.2.1. The nominal variation of frequency as per By-law 21 subsection 3(a) shall be $\pm 2.5\%$ of 50Hz. The generating units must be capable of continuous normal operation for the high and low frequency conditions set out in Clause 7.3.1 when the transmission system comes out of synchronism with the SAPP network
- 7.2.2. The Generating Units shall be capable of continuously supplying its Active Power output, as specified in the Contract with the Single Buyer, within the frequency range of 49.5 to 50.0 Hz. Any decrease of power output occurring in the frequency range of 49.5 to 48.5 Hz shall not be more than the required proportionate value of the Frequency decay.
- 7.2.3. Any Generation Unit and any Generation Power Station equipment shall be designed with anticipation of the following voltage conditions at the Connection Point:
- a) A voltage deviation in the range of 90% to 110% for protracted periods
 - b) A voltage drop to zero for up to 0.2s, to 75% for 2s, or to 85% for 60 s provided that during the 3 minute period immediately following the end of that 0.2s, 2s; 60s periods the actual voltage remains in the range 90-110% of the nominal voltage ;
 - c) Unbalance between phase voltages of not more than 3 % negative phase sequence and or the magnitude of one phase not lower by 5 % than any of the other two for 6 hours; and
 - d) A requirement to withstand the ARC cycle for faults on the transmission lines connected to the power station, being three single phase faults, each of 150 ms duration, within 31 seconds.

- 7.2.4. The Generating Unit shall be capable of supplying its Active Power and Reactive Power outputs, as specified in the Contract with the Single Buyer, within the voltage variations within the range +/- 5% during normal operating conditions. Any decrease of Reactive Power output occurring in the voltage range of - 10% shall not be more than the required proportionate value of the voltage variation.
- 7.2.5. Routine and prototype response tests shall be carried out to demonstrate capabilities as indicated in Sub-Section 7.17 under the parameter of Voltage and frequency withstand Capability.

7.3. ACTIVE POWER CONTROL

- 7.3.1. Design requirements: All units above 2.5 MVA shall have an operational governor that shall be capable of responding according to the following minimum requirements:

- a) High Frequency Requirements for Turbo-alternators Generation Units:
- a.1) All synchronised units shall respond by reducing active power to frequencies above 50 Hz plus allowable dead band described in clause 7.3.3. Speed governors shall be set to give a 4 % governor droop characteristic, or as otherwise agreed by the System and Market Operator. The response shall be fully achieved within 10 seconds and must be sustained for the duration of the frequency excursion. The unit shall respond to its full designed minimum operational capability at the time of the occurrence.
- a.2) **Over-frequency Conditions in the Range 51.5 to 52 Hz (Stage H1).** When the frequency goes above 51.5 Hz but less than 52 Hz the requirement is that the unit shall be designed to run for at least 10 minutes over the life of the plant. The turbo-alternator units shall be able to operate for at least 5 minutes continuously without tripping in this range.
- Exceeding this limit shall prompt the generator to take all reasonable efforts to reduce the system frequency below 51.5 Hz. Such actions can include manual tripping of the running unit(s). Tripping shall be staggered in time and be initiated once the frequency has been greater than 51.5 Hz for 5 minutes. The generator will trip a unit, and if the system frequency does not fall below 51.5 Hz, the other units shall be tripped in staggered format over the next five minutes or until the system frequency is below 51.5 Hz. The System and Market Operator shall approve this tripping philosophy and the settings.
- a.3) **Over-frequency Conditions in the above 52 Hz (Stage H2).** When the frequency goes above 52 Hz the requirement is that the unit shall be designed to run for at least 1 minute over the life of the plant. The turbo-alternator units shall be able to operate at least 30 seconds continuously without tripping in this range.
- When the system frequency exceeds 52 Hz, the generator can start tripping units sequentially. Tripping shall be spread over a 30-second window. If a generator chooses to implement automatic tripping, the tripping shall be staggered. The System and Market Operator shall approve this tripping philosophy and the settings. As an example, the first unit will trip in 5 seconds, the second unit trip in 10 seconds, etc.
- b) High Frequency Requirements for Hydro Generation Units.
- b.1) All synchronised hydro Generation Units shall respond by reducing active power to frequencies above 50 Hz plus allowable dead band described in clause 7.3.2 below. Speed governors shall be set to give a 4 % governor droop characteristic, or as otherwise agreed by the System and Market Operator). The response shall be fully achieved within 10 seconds and must be sustained for the duration of the frequency excursion. The unit shall respond to the full load capability range of the unit.

- b.2) Where the system is not designed for n-1 contingencies high over-frequency withstand capabilities are required. When the frequency goes above 54 Hz the requirement is that the unit shall be designed to run for at least 120 seconds over the life of the plant. It is expected that there will be less than 30 events of this nature for the lifetime of the unit (50 years). Hence the hydro-alternator units shall be able to operate at least 4 seconds in this range.
 - b.3) When the system frequency increases to 54 Hz for longer than 4 seconds, the generator shall start staggered tripping of units as per the procedure for turbo- alternators. Settings shall be agreed with the System and Market Operator.
 - c) Low Frequency Requirements for Turbo-alternator Generation Units
 - c.1) Low frequency response is a mandatory Ancillary Service defined as Spinning Reserve or Primary Reserve. All units shall be designed to be capable of having a 4 % governor droop characteristic, or as otherwise agreed by the System and Market Operator, with a minimum response of 3% of Maximum Continuous Rating (MCR) within 10 seconds of a frequency incident. The response must be sustained for at least 10 minutes. If 3% exceeds the power determined by the droop, then the droop takes precedence
 - c.2) **Low frequency in the Range 48.5 to 48.0 Hz (Stage L1).** When the frequency goes below 48.5 Hz but greater than 48.0 Hz the unit shall be designed to run for at least 10 minutes over the life of the plant. The unit shall be able to operate at least 5 minutes continuously without tripping while the frequency is in this range.

If the system frequency is in this range for more than 5 minutes, independent action may be taken by a generator to protect the unit.
 - c.3) **Low frequency in the Range 48.0 to 47.5 Hz (Stage L2).** When the frequency goes below 48.0 Hz but greater than 47.5 Hz the requirement is that the unit be designed to run for at least 1 minute over the life of the plant. The unit shall be able to operate at least 30 seconds continuously without tripping while the frequency is below 48.0 Hz but greater than 47.5 Hz.

If the system frequency is in this range for more than 30 seconds, independent action may be taken by a generator to protect the unit.
 - c.4) **Low frequency below 47.5 Hz (Stage L3).** If the system frequency falls below 47.5 Hz for longer than 6 seconds, independent action may be taken by a generator to protect the unit.
 - d) Low Frequency Requirements for Hydro-alternator Units
 - d.1) All reasonable efforts shall be made by the generator to avoid tripping of the hydro- alternator for under frequency conditions provided that the system frequency is above 46 Hz.
 - d.2) If the system frequency falls below 46 Hz for more than 1 second, independent action may be taken by a generator to protect the unit. Such action includes automatic tripping.
- 7.3.2. **Droop.** The speed governor must be capable of being set so that it operates with an overall speed droop between 2% and 9%.
- 7.3.3. **Dead band.** The maximum allowable dead band shall be 0.15 Hz for governing. This means that no response is required from the unit while the frequency is greater than 49.85 to and less than 50.15 Hz.
- 7.3.4. Routine and prototype response tests shall be carried out on the governing systems as indicated in Sub-Section 7.17 under Governing Response Tests

7.4. REACTIVE POWER REQUIREMENTS

- 7.4.1. All new units shall be capable of supplying rated power output Megawatt (MW) at any point between the limits 0.85 power factor lagging and 0.95 power factor leading at the unit terminals. Reactive output shall be fully variable between these limits under AVR, manual or other control.
- 7.4.2. Routine and prototype response tests shall be carried out to demonstrate reactive capabilities as indicated in Sub-Section 7.17.under Reactive Power Capability

7.5. EXCITATION SYSTEM REQUIREMENTS

- 7.5.1. A continuously-acting automatic excitation control system (AVR) shall be installed to provide constant terminal voltage control of the unit, without instability, over the entire operating range of the unit. (Note that this does not include the possible influence of a power system stabiliser.) Excitation systems shall comply with the requirements specified in IEC 60034.
- 7.5.2. The excitation control system shall be equipped with an under-excitation limiter, load angle limiter and flux limiter as described in IEC60034-16-1.
- 7.5.3. The excitation system shall have a minimum excitation ceiling limit of 1.6 p.u. rotor current, where 1 p.u. is the rotor current required to operate the unit at rated load and at rated power factor.
- 7.5.4. The settings of the excitation system shall be agreed between the System and Market Operator and each Generator, and shall be documented, with the master copy held by the System and Market Operator. The Generating Companies shall control all other copies. The procedure for this is shown Sub-Section 7.17 under Excitation and Setting Integrity Study
- 7.5.5. All new Generation Units and existing ones after a retrofitting process shall have and AVR equipped with power system stabilisers, as described in IEC60034-16-1. The Market and System and Market Operator may request that this equipment will also be installed in existing Generation Units, depending on IPS requirements. The requirements for other excitation control facilities and AVR refurbishment shall be determined in conjunction with the Market and System and Market Operator.
- 7.5.6. Generation Units shall be capable of operating in the full range as indicated in the capability diagram, which shall be supplied to the System and Market Operator as indicated in Part 6 (Information Exchange Code). Test procedures are shown in Sub-Section 7.17 under the Excitation Response Tests
- 7.5.7. Routine and prototype response tests shall be carried out on excitation systems as indicated in Sub-Section 7.17 on Excitation Systems and in accordance to IEC60034-16-3.

7.6. PROTECTION REQUIREMENTS

- 7.6.1. A Generating Unit, unit step-up transformer, unit auxiliary transformer, associated Busbar and switchgear shall be equipped with well-maintained Protection functions, in line with international best practices, to rapidly disconnect appropriate plant sections should a fault occur within the relevant Protection zones which fault may reflect into the TS; and
- 7.6.2. The following Protection functions shall be provided as defined to protect the IPS:
 - a) **Backup Impedance:** An impedance facility with a large reach shall be used. This shall operate for phase faults in the unit, in the HV switchyard or in the adjacent Transmission System lines, with a suitable delay, for cases when the

corresponding main Protection fails to operate. The impedance facility shall have fuse fail interlocking.

- b) **Loss of Field:** All Conventional Generating Units shall be fitted with a loss of field protection that matches the system requirements. The type of protection to be installed shall be agreed with the Transmission Licensee.
 - c) **Pole Slipping Facility (Out of Step):** Conventional Generating units shall be equipped with a pole slipping protection that matches the system requirements, where the System and Market Operator determines that it is required.
 - d) **Trip to House load:** This Protection shall operate in the event of a complete loss of load. For example, if all the feeder breakers open at a Power Station, power flow into the system is cut off and the generators will accelerate. At 50.5 Hz the over-frequency facility shall pick up to start the house loading process. At this stage, the HV breakers will still be closed. There will be power swings between the units and as soon as a unit has a reverse power condition the Protection shall open the HV breaker. The units shall island feeding their own auxiliaries. When system conditions have been restored then the islanded units can be re-synchronised to the system, under the direction of the System and Market Operator.
 - e) **Unit Transformer HV back-up Earth Fault Protection:** This is an IDMT protection that shall monitor the current in the *unit* transformer neutral. It can detect faults in the transformer *HV* side or in the adjacent network. The back-up earth fault facility shall trip the *HV* circuit-breaker.
 - f) **HV Breaker Fail Protection:** The “breaker fail” Protection shall monitor the HV circuit breaker’s operation for Protection trip signals, i.e. fault conditions. If a circuit breaker fails to open and the fault is still present after a specific time delay (nominally 120 ms), it shall trip the necessary adjacent circuit breakers.
 - g) **HV Pole discrepancy Protection:** The pole discrepancy agreement Protection shall cover the cases where one or two poles of a circuit breaker fail to operate after a trip or close signal.
 - h) **Unit Switch onto Standstill Protection:** This Protection shall be installed in the HV yard Substation or in the unit Protection panels. If this Protection is installed in the unit Protection panels, then the DC supply for this Protection and that used for the circuit-breaker closing circuit shall be the same. This Protection safeguards the generator against an unintended connection to the Transmission System (back energisation) when at standstill or at low speed.
- 7.6.3. Should system conditions dictate, the Transmission Licensee and/or the System and Market Operator is entitled to require the installation of additional Protections. The installation of these protections shall be agreed with the Generator and reflected in the Connection Agreement. In case of discrepancies, the issue should be referred to MERA for its final decision.
- 7.6.4. Required HV breaker tripping, fault clearance times, including breaker operating times depend on system conditions and shall be defined by the Transmission Licensee. Guide
- a) 80 ms where the Connection Point is 400 kV or above
 - b) 100 ms where the Connection Point is below 220kV or 275kV.
 - c) 120 ms where the Connection Point is below 132kV and below
- 7.6.5. Where generator breakers are installed on the LV side of the step up transformer, tripping and fault clearing including breaker interruption time, shall not exceed 120ms plus additional 30ms for DC offset decay.

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- 7.6.6. Where system conditions dictate, these times may be reduced by agreement between the Single Buyer and the Generator. Where so designed, earth fault clearing times for high resistance earthed systems may exceed the above tripping times. These aspects shall be reflected in the corresponding Connection Agreement.
 - 7.6.7. All Protection interfaces between the Generating Plant and the Transmission Licensee shall follow the Transmission Licensee testing and procedures as provided for in section 7.17.
 - 7.6.8. The settings of all the Protection tripping functions on the Protection system of a unit, relevant to IPS performance shall be co-ordinated with the Transmission System Protection settings decided by the Transmission Licensee in accordance with this Grid Code. The settings of all Protections of the Generating Plant shall be agreed between the Transmission Licensee and the Generator. These settings shall be reflected in the Connection Agreement.
 - 7.6.9. For system abnormal conditions, a unit is to be disconnected from the TS in response to conditions at the Connection Point, only when the system conditions are outside the plant capability where damage will occur. The Connection Agreement shall detail plant capabilities and the relevant Protection operations.
 - 7.6.10. Competent persons shall carry out testing, commissioning, and configuration of Protection systems. Prototype and routine testing shall be carried out as defined Sub-Section 7.17 under Protection and Function and Setting Integrity Study.
 - 7.6.11. Any work on the Protection circuits interfacing with Transmission System Protection systems (e.g. bus zone) must be communicated to the Transmission Licensee before commencing the works. For the avoidance of doubt, this includes any kind of work performed during a unit outage.

7.7. ABILITY OF UNITS TO ISLAND

- 7.7.1. Generation Units which do not have black start capability of less than one hour without power from the Transmission System shall be capable of Islanding.
- 7.7.2. Islanding testing shall be contracted as an Ancillary Service. The procedure for testing is given in Sub-Section 7.17 under the Islanding Study .

7.8. MULTIPLE UNIT TRIPPING (MUT) RISKS

- 7.8.1. A Generation Power Station and its units shall be designed, maintained and operated to minimise the risk of more than one unit being tripped from one common cause within a short time.
 - a.1) **Category 1:** Unplanned disconnection or tripping of more than one unit instantaneously or within a one hour window, where the total maximum continuous rating (MCR) of those units exceeds the largest credible multiple contingencies.
 - a.2) **Category 2:** Unplanned disconnection or tripping more than one unit instantaneously or within ten minutes, where the total MCR of those units exceeds the largest single contingency.
- 7.8.2. The Generation Power Station shall be designed such that no MUT category 1 trip risk can occur and a MUT category 2 trip will not occur more than once in ten years.
- 7.8.3. The Generation Power Station shall calculate the minimum number of units required to trip for each category and identify potential common elements in the power station that can cause an MUT category 1 or 2 trip. The power station shall inform the System and Market Operator of these causes with corrective actions planned.

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- 7.8.4. Should the System and Market Operator determines that a power station presents an unacceptable MUT risk for the network, the relevant generator and the System and Market Operator shall agree on the corrective action required to reduce the MUT risk and time frames within which to comply.

7.9. BLACK START REQUIREMENTS

- 7.9.1. Generation Power Stations that have declared having black start capability shall demonstrate this facility by test as described in Sub-Section 7.17 under Power Station Black Start Capability
- 7.9.2. Back start capable Power Stations may be called from time to time not to carry out a full station black start but a unit black start as described in Sub-Section 7.17 under the Station Black Starting Capability.

7.10. RESTART AFTER POWER STATION BLACK-OUT

7.10.1. Thermal Power Stations

- a) A Thermal Power Station and all its Generation Units shall be capable of being restarted and synchronised to the IPS following restoration of external auxiliary AC supply without unreasonable delay resulting directly from the loss of external auxiliary AC supply;
- b) For the purposes of this code, examples of unreasonable delay in the restart of a Power Station includes:
 - b.1) Restart of the first unit that takes longer than 4 hours after restart initiation
 - b.2) Restart of the second unit that takes longer than 2 hours after the synchronising of the first unit.
 - b.3) Restarting of all other units that take longer than 1 hour each after the synchronising of the second unit;
 - b.4) Delays not inherent in the design of the relevant start up facilities and which could reasonably be minimised by the relevant generator; and
 - b.5) The start-up facilities for a new unit not being designed to minimise start up time delays for the unit following loss of external auxiliary AC supplies for two hours or less.
- c) Routine and prototype response tests shall be carried out to demonstrate capabilities as indicated in Sub-Section 7.17 under Power Station Black Start Capability

7.10.2. Hydro and Gas turbines

- a) A Hydro or Gas Turbines Power Station and all its Generation Units shall be capable of being restarted and synchronised to the IPS following restoration of external auxiliary AC supply without unreasonable delay resulting directly from the loss of external auxiliary AC supply.
- b) For the purposes of this code, examples of unreasonable delay in the restart of a Hydro or Gas Turbines Power Station includes:
 - b.1) Restart of the first unit that takes longer than 30 minutes after restart initiation;
 - b.2) Restarting of all other units that take longer than 30 minutes each after the synchronising of the first unit;
 - b.3) Delays not inherent in the design of the relevant start up facilities and which could reasonably be minimised by the relevant generator; and

- b.4) The start-up facilities for a new unit not being designed to minimise start up time delays for the unit following loss of external auxiliary AC supplies for 30 minutes or less.
- c) Routine and prototype response tests shall be carried out to demonstrate capabilities as indicated in Sub-Section 7.17 under the Generating Unit Restart after Station Blackout Capability.

7.11. ON LOAD TAP CHANGING FOR GENERATING UNIT STEP-UP TRANSFORMERS

- 7.11.1. All Generating Unit step-up transformers shall have on-load tap changing which can be remotely controlled. The range shall be agreed between the Transmission Licensee, upon consultation with the System and Market Operator, and the Generator.
- 7.11.2. Routine and prototype response tests shall be carried out on Generating Unit Step-Up on Load Tap changing Transformers as indicated in Sub-Section 7.17 under On Load Tap Changing Capability

7.12. TESTING AND COMPLIANCE MONITORING

- 7.12.1. A Generator shall keep records relating to the compliance by each of its Units with each section of this code applicable to that unit, setting out such Information that the System and Market Operator reasonably requires for assessing power system performance (including actual unit performance during abnormal conditions).
- 7.12.2. Within one Month after the end of June and December, a Generator shall review, and confirm to the System and Market Operator, the Transmission Licensee or the Single Buyer, as it corresponds, compliance by each of that Generating Units with every requirement of this Grid Code the past 6 month period. Refer to Appendix 3 of the Information Exchange Code.
- 7.12.3. A Generator shall conduct tests or studies to demonstrate that each Power Station and each Generating Unit complies with each of the requirements of this Grid Code. Tests shall be carried out on new units, after every outage where the integrity of any requirement stated above may have been compromised, to demonstrate the compliance of the unit with the relevant requirements. The Generator shall continuously monitor its compliance with all the connection conditions of the Grid Code.
- 7.12.4. Each Generator shall submit to the System and Market Operator, the Transmission Licensee, or the Single Buyer, as it corresponds, a detailed test procedure, emphasizing system impact, for each relevant part of this code prior to every test.
- 7.12.5. If a Generator determines, from tests or otherwise, that one of its Units or Power Stations is not complying with one or more sections of this code, then the generator shall:
 - a) promptly notify the System and Market Operator, the Transmission Licensee, or the Single Buyer, as it corresponds, of that fact;
 - b) promptly advise the System and Market Operator, the Transmission Licensee or the Single Buyer, as it corresponds, of the remedial steps it proposes to take to ensure that the relevant unit or Power Station (as applicable) can comply with this code and the proposed timetable for implementing those steps;
 - c) Diligently take such remedial action as will ensure that the relevant unit or Power Station (as applicable) can comply with this code. The Generator shall regularly report in writing to the System and Market Operator, Transmission Licensee or Single Buyer, as it corresponds, on its progress in implementing the remedial action; and

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- d) After taking remedial action as described above, demonstrate to the reasonable satisfaction of the System and Market Operator, Transmission Licensee or Single Buyer, as it corresponds, that the relevant Unit or Power Station (as applicable) is then complying with this code.

7.13. NON-COMPLIANCE SUSPECTED BY THE SYSTEM AND MARKET OPERATOR

7.13.1. If at any time the System and Market Operator or the Single Buyer, as it corresponds, believe that a unit or Power Station is not complying with this code, the System and Market Operator or the Single Buyer must notify the relevant generator of such non-compliance specifying the code section concerned and the basis for the System and Market Operator's or Single Buyer belief.

7.13.2. If the relevant Generator considers that the unit or Power Station (as applicable) is complying with the Code, then the System and Market Operator, the Single Buyer and the Generator must promptly meet to resolve their differences. In case the discrepancy persists, the System and Market Operator or the Single Buyer, as it corresponds, is entitled to request specific tests to verify actual Grid Code compliance.

7.14. UNIT MODIFICATIONS

7.14.1. Modification proposals

- a) If a Generator proposes to change or modify any of its Units in a manner that could reasonably be expected to either adversely affect that Unit's ability to comply with this Code, or changes its performance, Information supplied, settings, etc., then the Generator shall submit a proposal notice to the System and Market Operator, Transmission Licensee or Single Buyer, as it corresponds, which shall:
 - a.1) Contain detailed plans of the proposed change or modification;
 - a.2) State when the generator intends to make the proposed change or modification; and
 - a.3) Set out the proposed tests to confirm that the relevant unit as changed or modified operates in the manner contemplated in the proposal, can comply with this code.
- b) If the System and Market Operator, Transmission Licensee or Single Buyer, as it corresponds, disagrees with the proposal submitted, it may notify the relevant Generator, and the System and Market Operator, Transmission Licensee or Single Buyer, as it corresponds, and the relevant Generator shall promptly meet and discuss the matter in good faith in an endeavour to resolve the disagreement. In case it is not possible to reach such agreement, the matter shall be submitted to MERA for its final decision.

7.14.2. Implementing modifications

- a) The Generator shall ensure that an approved change or modification to a Unit or to a subsystem of a Unit is implemented in accordance with the relevant proposal approved by the System and Market Operator, Transmission Licensee or Single Buyer, as it corresponds.
- b) The Generator shall notify the System and Market Operator, Transmission Licensee or Single Buyer, as it corresponds, promptly after an approved change or modification to a unit has been implemented.

7.14.3. Testing of modifications

- a) The Generator shall confirm that a change or modification to any of its Units, as described above, conforms to the relevant proposal by conducting the relevant tests, in relation to these Connection Conditions, promptly after the proposal has been implemented.
- b) Within 20 business days after any such test has been conducted, the relevant Generator shall provide the System and Market Operator, Transmission Licensee or Single Buyer, as it corresponds, with a report in relation to the tests actually performed, including the results of such tests.
- c) The System and Market Operator, the Single Buyer and/or the Transmission Licensee are entitled to be present when such tests are carried out.
- d) Test results shall be attached to the Connection Agreement.

7.15. EQUIPMENT REQUIREMENTS

7.15.1. Where the Generator needs to install equipment that connects directly with the Transmission Licensee equipment, for example in the high voltage switchyard of the Transmission Licensee substation, such equipment shall adhere to the Transmission Licensee design requirements as set out in this Code.

7.15.2. The Transmission Licensee may require Customers to provide documentary proof that their connection equipment complies with all relevant standards, both by design and by testing.

7.16. SURVEYING, MONITORING AND TESTING OF GENERATING UNITS

7.16.1. This sub-section specifies the procedures to be followed in carrying out the surveying, monitoring or testing of Generating Units to confirm the:

- a) compliance by the Power Stations with the Grid Code; and
- b) provision by the Power Stations of ancillary services which they are required or have agreed to provide.

7.16.2. Request for surveying, monitoring or testing

The System and Market Operator and/or the Single Buyer may at any time (although it may not do so more than twice in any calendar year in respect of any particular Power Station except to the extent that it can on reasonable grounds justify the necessity for further tests or unless the further test is a re-test) issue an instruction requiring a Power Station to carry out a test, at a time no sooner than 48 hours from the time that the instruction was issued, to demonstrate that the relevant Power Station complies with the Grid Code requirements.

7.16.3. Ongoing Monitoring of a Generating Unit's Performance

- a) A Generating Company shall monitor each of its Generating Units during normal service to confirm ongoing compliance with the applicable parts of this code. Any deviations detected must be reported to the System and Market Operator within 5 working days.
- b) A Generating Company shall keep records relating to the compliance by each of its Generating Units with each section of this code applicable to that unit, setting out such Information that the System and Market Operator or Transmission Licensee reasonably requires for assessing power system performance (including actual unit performance during abnormal conditions).
- c) Within one Month after the end of June and December, a Generating Company shall provide to the System and Market Operator a report detailing the compliance by each of that Company's Generating Units with every code section

during the past 6 month period. The reporting template is attached as Appendix 2 of the Information Exchange Code

7.17. PROCEDURES

7.17.1. Generating Unit Protection System

Parameter	Grid Code Reference	Details
<p style="text-align: center;">Protection and Function and Setting Integrity Study</p>	<p>Sub-Section 7.6</p>	<p>APPLICABILITY AND FREQUENCY Prototype Study: All new <i>Power Stations</i> coming on line or <i>Power Stations</i> where major refurbishment or <i>Protection</i> system upgrades have taken place. Routine Review: All <i>Power Stations</i> every 5 to 6 years.</p>
		<p>PURPOSE: To ensure that the relevant <i>Protection</i> functions in the <i>Power Station</i> are co-ordinated and aligned with the system requirements.</p>
		<p>PROCEDURE Prototype:</p> <ol style="list-style-type: none"> 1. Establish the System <i>Protection</i> function and associated trip level requirements from <i>the Transmission Licensee</i>. 2. Derive <i>Protection</i> functions and settings that match the <i>Power Station</i> plant, <i>the Transmission Licensee</i> plant and system requirements. 3. Confirm the stability of each <i>Protection</i> function for all relevant system conditions. 4. Document the details of the trip levels, stability calculations for each <i>Protection</i> function. 5. Convert <i>Protection</i> tripping levels for each <i>Protection</i> function into per unit base. 6. Consolidate all settings in per unit base for all <i>Protection</i> functions in one document. 7. Derive actual relay dial setting details and document the relay setting sheet for all <i>Protection</i> functions. 8. Document the position of each <i>Protection</i> function on one single line diagram of the <i>Generating Unit</i> and associated connections. 9. Document the tripping functions for each tripping function on one tripping logic diagram. 10. Consolidate detailed setting calculations, per unit setting sheets, relay setting sheets, plant base 11. <i>Information</i> the settings are based on, tripping logic diagram, <i>Protection</i> function single line diagram and relevant <i>Protection</i> relay manufacturers' <i>Information</i> into one document. 12. Submit the documentation to <i>the Transmission Licensee</i> for their acceptance and database update. 13. Provide <i>the Transmission Licensee</i> with one original reference copy and one working copy.
		<p>Review:</p> <ol style="list-style-type: none"> 1. Review Items 1 to 10 above. 2. Submit the documentation to <i>the Transmission Licensee</i> for their acceptance and update. 3. Provide <i>the Transmission Licensee</i> with one original reference copy and one working copy. <p>ACCEPTANCE CRITERIA All <i>Protection</i> functions should be set to meet the necessary <i>Protection</i> requirements of the <i>TS</i> and <i>Power Station</i> plant with minimal margin, optimal fault clearing times and maximum plant availability. Submit a report to <i>the Transmission Licensee</i> one <i>month</i> after commissioning for prototype study or 5 to 6 yearly for routine tests.</p>

7.17.2. Protection Integrity Tests

Parameter	Grid Code Reference	Details
<p style="text-align: center;">Protection Integrity Tests</p>	<p>Sub-Section 7.6</p>	<p>APPLICABILITY Prototype test: At all new <i>Power Stations</i> coming on line and all other <i>Power Stations</i> after major modifications or refurbishment of <i>Protection</i> or related plant. Routine test: At all <i>Power Stations</i> 5 to 6 yearly or after major overhaul of plant.</p>
		<p>PURPOSE: To confirm that the <i>Protection</i> has been wired and function according to the specified.</p>
		<p>PROCEDURE</p> <ol style="list-style-type: none"> 1. Apply final settings, as per agreed documentation, to all <i>Protection</i> functions. 2. With the <i>Generating Unit</i> off load and de-energized, inject appropriate signals into every <i>Protection</i> function and confirm correct operation and correct calibration. Document all <i>Protection</i> function operations. 3. Carry out trip testing of all <i>Protection</i> functions, from origin (e.g. Buchholz relay) to all tripping output devices (e.g. <i>HV Breaker</i>). Document all trip test responses. 4. Apply short circuits at all relevant <i>Protection</i> zones and with <i>generator</i> at nominal speed excite <i>generator</i> slowly, record currents at all relevant <i>Protection</i> functions, and confirm correct operation of all relevant <i>Protection</i> functions. Document all readings and responses. Remove all short circuits. 5. With the <i>generator</i> at nominal speed, excite <i>generator</i> slowly, recording voltages on all relevant <i>Protection</i> functions. 6. Confirm correct operation and correct calibration of all <i>Protection</i> functions. Document all readings and responses.
		<p>ACCEPTANCE CRITERIA</p> <ol style="list-style-type: none"> 1. All <i>Protection</i> functions shall be fully operational and operate to required levels within the Original Equipment Manufacturer (<i>OEM</i>) allowable tolerances. 2. Measuring instrumentation used shall be sufficiently accurate and calibrated to traceable standards
		<p>A report shall be submitted to <i>the Transmission Licensee</i> one month after test.</p>

7.17.3. Generating Unit Islanding Capability

Parameter	Grid Code Reference	Details
Islanding Capability	Sub-Section 7.7	<p>APPLICABILITY <i>Prototype test:</i> For all other fossil and Nuclear <i>Power Stations</i>. <i>Routine test:</i> For stations that have contracted to Island under the <i>Ancillary Services Agreement</i>. 5-6 yearly or after modifications done to plant that may affect <i>Islanding Capability</i> <i>Continuous monitoring:</i> Where in the <i>day to day</i> running of the plant, a real condition arises where a <i>Generating Unit</i> is required to Island, and the <i>Islanding</i> takes place successfully, and the <i>Islanding</i> condition is sustained as specified under acceptance criteria below or is called upon to synchronize and complete synchronizing successfully, it shall be considered as a successful <i>Islanding test</i>.</p>
		<p>PURPOSE To confirm that <i>Generating Units</i> that have specified and/or contracted to provide an <i>Islanding service</i>, comply. <i>Islanding</i> is the ability of a <i>Generating Unit</i> to suddenly disconnect from the <i>TS</i> by the opening of the <i>HV breaker</i>, and automatically control all the necessary critical parameters sufficiently to maintain the <i>turbine-generator</i> at speed and excited and supplying its own auxiliary load. This Islanded mode must be sustained for at least 20 minutes without tripping of the turbine, boiler, excitation system, or other systems critical to sustaining of an <i>Islanding</i> condition.</p>
		<p>PROCEDURE</p> <ol style="list-style-type: none"> 1 <i>Generating Unit</i> running at steady state conditions above 60% full load conditions. 2 All <i>Protection</i> and control systems in normal operating conditions. 3 No special modifications to the plant for the purpose of the test, except installation of monitoring equipment, are allowed. 4 The <i>Generating Unit</i> supplies all its own auxiliary load during the test 5 No operation is allowed for the first 5 minutes following the initiation of the <i>Islanding</i>. 6 Equipment is connected to the <i>Generating Unit</i> that records critical parameters. 7 The following parameters are recorded as a minimum: <ol style="list-style-type: none"> (a) Turbine speed (b) Alternator load (c) Alternator voltage and current (d) Exciter voltage and current (e) Unit board voltage (f) Anticipatory device position (where installed) (g) System frequency 8 Initiation of the <i>Islanding</i> is done by opening the <i>HV Breaker</i>
		<p>ACCEPTANCE CRITERIA The turbine must settle at or close to its nominal speed, the excitation system must remain in automatic channel, supplying all the unit's auxiliary load. The <i>Islanding</i> condition must be sustained for at least 20 minutes.</p>

7.17.4. Excitation System

Parameter	Grid Code Reference	Details
<p style="text-align: center;">Excitation and Setting Integrity Study</p>	<p style="text-align: center;">Sub-Section 7.5</p>	<p>APPLICABILITY AND FREQUENCY</p> <p>Prototype study: At all new <i>Power Stations</i> coming on line or <i>Power Stations</i> where major refurbishment or <i>Protection</i> system upgrades have taken place.</p> <p>Routine review: At all <i>Power Stations</i> every 5 to 6 years.</p>
		<p>PURPOSE</p> <p>To ensure that the Excitation systems in the <i>Power Station</i> are co-ordinated and aligned with the system requirements</p>
		<p>PROCEDURE</p> <p>Prototype:</p> <ol style="list-style-type: none"> 1. Establish the System excitation system performance requirements from <i>the System and Market Operator</i>. 2. Derive a suitable model for the excitation system according to IEEE421.5 or IEC 60034.16.2. Where necessary, nonstandard models (non IEC or IEEE) shall be created. This may require <i>frequency</i> response and bode plot tests on the excitation system as described in IEEE 421.2.1990. 3. Submit the model to <i>the System and Market Operator</i> for their acceptance. 4. Derive excitation system settings that match the <i>Power Station</i> plant, <i>TS</i> plant and system requirements. This includes the settings of all parts of the excitation system such as the chop-over limits and levels, limiters, <i>Protection</i> devices, alarms. 5. Confirm the stability of the excitation system for relevant excitation system operating conditions. 6. Document the details of the trip levels, and stability calculations for each setting and function. 7. Convert settings for each function into Per Unit (<i>P.U.</i>) base and produce a high level dynamic performance model with actual settings in <i>P.U.</i> values. 8. Derive actual card setting details and document the relay setting sheet for all setting functions. 9. Produce a single line diagram / block diagram of all the functions in the excitation system and indicate signal source. 10. Document all the tripping functions on one tripping logic diagram. 11. Consolidate detailed setting calculations, model, Per Unit setting sheets, relay setting sheets, plant base <i>Information</i> the settings are based on, tripping logic diagram, <i>Protection</i> function single line diagram and relevant <i>Protection</i> relay manufacturers <i>Information</i> into one document. 12. Submit to <i>the System Operator</i> for their acceptance and update. 13. Provide <i>the System and Market Operator</i> with one original master copy and one working copy.

Parameter	Grid Code Reference	Details
		<p>Review:</p> <ol style="list-style-type: none"> 1 Review Items 1 to 10 above 2 Submit the documentation to <i>the System and Market Operator</i> for their acceptance and update 3 Provide <i>the System and Market Operator</i> with one original master copy and one working copy update if applicable <hr/> <p>ACCEPTANCE CRITERIA</p> <ol style="list-style-type: none"> 1. Excitation system is set to meet the necessary control requirements in an optimized manner for the performance of the <i>TS</i> and <i>Power Station</i> plant. Excitation system operates in a stable manner both internally and on the network 2. Submit a report to <i>the System and Market Operator</i> one <i>month</i> after commissioning for prototype study or 5 to 6 yearly for routine tests, within one <i>month</i> after due date expiry

7.17.5. Excitation Response Tests

Parameter	Grid Code Reference	Details
Excitation Response Tests	Sub-Section 7.5	<p>APPLICABILITY <i>Prototype test:</i> At all new <i>Power Stations</i> coming on line and all other <i>Power Stations</i> after major modifications or refurbishment of <i>Protection</i> or related plant <i>Routine test:</i> At all <i>Power Stations</i> 5 to 6 yearly or after major overhaul of plant.</p>
		<p>PURPOSE To confirm that the excitation system performs according to specifications</p>
		<p>PROCEDURE</p> <ol style="list-style-type: none"> 1. With the <i>generator</i> off line, carry out <i>frequency scan / bode plot</i> tests on all circuits in the excitation system critical to the performance of the excitation system. 2. With the <i>generator</i> in the open circuit mode, carry out the Large signal performance testing as described in IEEE 421.2 of 1990. Determine Time Response, Ceiling Voltage, and Voltage Response, 3. With the <i>generator</i> connected to the network and loaded, carry out the small signal performance tests according to IEE 421.2.1990. Also carry out Power System Stabiliser tests and determine damping with and without Power System Stabiliser. 4. Document all responses
		<p>ACCEPTANCE CRITERIA Excitation system meets the necessary control requirements in an optimized manner for the performance of the <i>TS</i> and <i>Power Station</i> plant as specified. Excitation system operates in a stable manner both internally and on the network. Power System stabilizers are set for optimized damping</p>

7.17.6. **Generating Unit Reactive Power Capability**

Parameter	Grid Code Reference	Details
<p>Reactive Power Capability</p>	<p>Sub-Section 7.4</p>	<p>APPLICABILITY <i>Prototype test:</i> At all new <i>Power Stations</i> coming on line and all other <i>Power Stations</i> after major modifications or refurbishment of <i>Protection</i> or related plant.</p>
		<p>PURPOSE To confirm that the Reactive Power Capability specified is met.</p>
		<p>PROCEDURE The duration of the test will be up to 60 minutes, during which period the system voltage at the Grid Entry Point for the relevant <i>Generating Unit</i> will be maintained by the <i>Generating Company</i> at the voltage specified, through adjustment of Reactive Power on the remaining <i>Generating Units</i>, if necessary.</p>
		<p>ACCEPTANCE CRITERIA <i>Generating Unit</i> will pass the test if it is within $\pm 5\%$ of the capability registered with <i>the Single Buyer</i>. Submit a report to <i>the Single Buyer</i> one month after test</p>

7.17.7. Power Station Multiple Unit Trip

Parameter	Grid Code Reference	Details
<p align="center">Multiple Unit Tripping (MUT) Tests, Study and Survey</p>	<p align="center">Sub-Section 7.8</p>	<p>APPLICABILITY Prototype tests / study / survey: (a) At new <i>Power Stations</i> coming on line, items 1 to 5 below; or (b) At <i>Power Stations</i> where major modifications or changes have been implemented on plant critical to Multiple Unit Tripping. Applicable item/s listed 1 to 5 below Routine assessment: At all <i>Power Stations</i>. Item 5 below. Annually Routine testing: At all <i>Power Stations</i>. Every 5 to 6 years or after a major overhaul. Items 1 to 4 below</p>
		<p>PURPOSE To confirm that a <i>Power Station</i> is not subjected to unreasonable risk of <i>MUT</i> as defined in Network Code section 3.1.5</p>
		<p>PROCEDURE 1 Emergency Supply Isolation Test: On all <i>emergency</i> supplies (e.g. <i>DC</i> supplies) common to more than one <i>Generating Unit</i>, isolate supply for at least one second, with the <i>Generating Unit</i> running at full load under normal operating conditions. Tests are carried out on one <i>Generating Unit</i> at the time. Where two supplies feed one common load, isolation of one supply at a time would be sufficient. Confirm that the <i>Generating Unit</i> or part of the unit plant does not trip. No change in the unit output shall take place. Document results 2 Disturbance on DC Supply Survey: On all <i>DC</i> supplies common to more than one <i>Generating Unit</i>, carry out a survey of the immunity of all devices that are part of tripping circuits, to supply voltage All devices on <i>DC</i> supplies common to more than one <i>Generating Unit</i> that form part of tripping circuits or that can cause tripping or <i>Load Reduction</i> on a unit must comply to <i>IEC specifications</i>. Document findings. 3 Uninterruptible Power Supply (UPS) Integrity Testing: On all <i>UPS's</i> supplying critical loads that can cause tripping of more than one <i>Generating Unit</i> within the time zones specified in 3.1.5, isolate the <i>AC</i> supply to the <i>UPS</i> for a period of at least 1 minute. Where two <i>UPS's</i> supply one common load, one <i>UPS</i> at a time can be isolated. Load equipment must resume normal operation. Document results. 4 Earth-mat Integrity Inspection and Testing: Carry out an inspection and tests on all parts of the <i>Power Station</i> earth mat that is exposed to lightning surge entry and in close proximity to circuits vulnerable to damage that will result in tripping of more than one <i>Generating Unit</i> within the time zones specified in 2.2.1.5 (e.g. chimneys at fossil power stations or penstocks at hydro power stations) Confirm that all the earthing and bonding is in place, and measure resistances to earth at bonding points. Document findings and results. 5 MUT Risk Assessment Identify all power supplies, air supplies, water supplies, and other supplies / systems common to more than one <i>Generating Unit</i> that are likely to cause the tripping of more than one <i>Generating Unit</i> within the <i>MUT</i> time zones specified in section 2.2.1.5. Calculate the probability of tripping in all the Zone 1, Zone 2 and Zone 3 <i>MUT</i> risk areas for the <i>Power Station</i>. Document all findings, listing all risks and probabilities.</p>
		<p>ACCEPTANCE CRITERIA</p>

		<p>No unreasonable <i>MUT</i> items as listed in 2.2.1.5 shall be present. Probability of a Zone 3 <i>MUT</i> must be less than (To be determined) Zone 2 shall be less than (To be determined) and Zone 1 shall be less than (To be determined).</p> <p>Report to be submitted to <i>the Transmission Licensee and the Single Buyer</i> one <i>Month</i> after testing. Routine studies, and survey reports to be submitted one month after expiry of due date</p>
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7.17.8. Governing System

Parameter	Grid Code Reference	Details
Governing Response Tests	Sub-Section 7.3	<p>APPLICABILITY</p> <p><i>Prototype test:</i> At all new <i>Power Stations</i> coming on line and all other <i>Power Stations</i> after major modifications or refurbishment of <i>Protection</i> or related plant.</p> <p><i>Routine test:</i> All <i>Generating Units</i> to be monitored continuously. Additional tests may be requested by the <i>System and Market Operator</i></p>
		<p>PURPOSE</p> <p>To prove that the <i>Generating Unit</i> is capable of complying with the minimum requirements required for <i>Governing</i>.</p>
		<p>PROCEDURE</p> <ol style="list-style-type: none"> 1. <i>Frequency</i> or speed deviation to be injected on the <i>Generating Unit</i> for 10 minutes. 2. Real Power Output of the <i>Generating Unit</i> is to be measured and recorded
		<p>ACCEPTANCE CRITERIA</p> <p>Minimum requirements of the <i>Grid Code</i> are met</p>

7.17.9. Generating Unit Restart after Station Blackout Capability

Parameter	Grid Code Reference	Details
<p>Restart after Station Blackout</p>	<p>Sub-Section 7.10</p>	<p>APPLICABILITY Prototype Survey: Item 1 for new <i>Power Stations</i> or <i>Power Stations</i> where modifications have been carried out on plant critical to multiple <i>Generating Unit</i> restarting. Routine Survey: At all <i>Power Stations</i>. Item 2 every 3 months.</p>
		<p>PURPOSE To confirm that a <i>Power Station</i> can restart <i>Generating Units</i> simultaneously to the criteria outlined in section 2.2.1.7 after a station blackout condition.</p>
		<p>PROCEDURE 1. Plant Capacity Survey: Identify all supply systems common to two or more systems (e.g. Power supplies, crude oil, air, demineralised water) (a) Determine the quantity and supply rate required to simultaneously restart the number of <i>Generating Units</i> specified in section 2.2.1.7 (b) Document a list of critical systems, required stock, study details and findings. 2. Survey of Available Stock: For each of the applicable critical systems identified, document the average stock for the year, minimum stock, and duration below critical stock levels.</p>
		<p>ACCEPTANCE CRITERIA More than 95% of the time of the year, all stocks above critical levels. Report to be submitted to <i>the System and Market Operator and the Single Buyer</i> one month after commissioning. Routine survey reports to be submitted one month after expiry of due date</p>

7.17.10. Power Station Black Start Capability

Parameter	Grid Code Reference	Details
<p>Generating Unit Black Starting Capability</p>	<p>Sub-Section 7.9</p>	<p>APPLICABILITY <i>Routine Test:</i> Power Stations that have contracted under the ancillary services to supply Unit Black Start services. When called for by the System and Market Operator but not more than once every 2 years</p>
		<p>PURPOSE To demonstrate that a Black Start Unit has a Black Start Capability</p>
		<p>PROCEDURE</p> <ol style="list-style-type: none"> 1. The relevant <i>Generating Unit</i> shall be synchronised and loaded; 2. All the Auxiliary Gas Turbines and/or Auxiliary Diesel Engines in the <i>Black Start Station</i> in which that <i>Generating Unit</i> is situated, shall be shut down. 3. The <i>Generating Unit</i> shall be de-loaded and de-synchronised and all alternating current electrical supplies to its Auxiliaries shall be disconnected. 4. The Auxiliary Gas Turbine(s) or Auxiliary Diesel Engine(s) to the relevant <i>Generating Unit</i> shall be started and shall re-energise the Unit Board of the relevant <i>Generating Unit</i>. 5. The Auxiliaries of the relevant <i>Generating Unit</i> shall be fed by the Auxiliary Gas Turbine(s) or Auxiliary Diesel Engine(s), via the Unit Board, to enable the relevant <i>Generating Unit</i> return to Synchronous Speed. 6. The relevant <i>Generating Unit</i> shall be synchronised to the System but not loaded unless the appropriate instruction has been given by the System and Market Operator. <p>All Black Start Tests shall be carried out at the time specified by the System and Market Operator in the notice given under 2.2.1.8 and shall be undertaken in the presence of a reasonable number of representatives appointed and authorised by the System and Market Operator, who shall be given access to all Information relevant to the Black Start Test</p>
		<p>ACCEPTANCE CRITERIA</p> <ol style="list-style-type: none"> 1 A Black Start Station shall fail a Black Start Test if the Black Start Test shows that it does not have a Black Start Capability (i.e. if the relevant <i>Generating Unit</i> fails to be synchronised to the System within two hours of the Auxiliary Gas Turbine(s) or Auxiliary Diesel Engine(s) being required to start). 2 Submit a report to the System and Market Operator one Month after the test

7.17.11. Station Black Starting Capability

Parameters	Grid Code reference	Details
<p>Station Black Starting Capability</p>	<p>Sub-Section 7.9</p>	<p>APPLICABILITY</p> <p><i>Routine test: All Stations contracted under Ancillary Services to provide a Station Black Start service. When called for by the System and Market Operator but not more than once every 2 years</i></p>
		<p>PURPOSE: Demonstrate that a Black Start Station has a Black Start Capability</p>
		<p>PROCEDURE</p> <ol style="list-style-type: none"> 1. All <i>Generating Units</i> at the <i>Black Start Station</i>, other than the <i>Generating Unit</i> on which the <i>Black Start Test</i> is to be carried out, and all the <i>Auxiliary Gas Turbines</i> and/or <i>Auxiliary Diesel Engines</i> at the <i>Black Start Station</i>, shall be shut down. 2. The relevant <i>Generating Unit</i> shall be synchronised and loaded. 3. The relevant <i>Generating Unit</i> shall be de-loaded and de-synchronised. 4. All external alternating current electrical supplies to the Unit Board of the relevant <i>Generating Unit</i>, and to the Station Board of the relevant <i>Black Start Station</i>, shall be disconnected. 5. An <i>Auxiliary Gas Turbine</i> or <i>Auxiliary Diesel Engine</i> at the <i>Black Start Station</i> shall be started, and shall re-energise either directly, or via the Station Board, the Unit Board of the relevant <i>Generating Unit</i>. 6. The <i>Auxiliaries</i> of the relevant <i>Generating Unit</i> shall be fed by the <i>Auxiliary Gas Turbine(s)</i> or <i>Auxiliary Diesel Engine(s)</i>, via the Unit Board, to enable the relevant <i>Generating Unit</i> to return to Synchronous Speed 7. The relevant <i>Generating Unit</i> shall be synchronised to the System but not loaded unless the appropriate instruction has been given by the <i>System and Market Operator</i>. <p>All <i>Black Start Tests</i> shall be carried out at the time specified by the <i>System and Market Operator</i> in the notice given under 2.2.1.8 and shall be undertaken in the presence of a reasonable number of representatives appointed and authorised by the <i>System and Market Operator</i>, who shall be given access to all <i>Information</i> relevant to the <i>Black Start Test</i>.</p>
		<p>ACCEPTANCE CRITERIA</p> <p>A <i>Black Start Station</i> shall fail a <i>Black Start Test</i> if the <i>Black Start Test</i> shows that it does not have a <i>Black Start Capability</i> (i.e. if the relevant <i>Generating Unit</i> fails to be synchronised to the System within two hours of the <i>Auxiliary Gas Turbine(s)</i> or <i>Auxiliary Diesel Engine(s)</i> being required to start).</p> <p>Submit a report to the <i>System and Market Operator</i> one month after test.</p>

7.17.12. External Supply Disturbance Withstand Capability

Parameter	Grid Code Reference	Details
<p align="center">Voltage and Frequency withstand Capability</p>	<p align="center">Sub-Section 7.2</p>	<p>APPLICABILITY Prototype Survey / Test: At new Power Stations coming online or Power Stations where major modifications to plant that may be critical to system supply frequency or voltage magnitude deviations have been done. Items 1 to 3 and 4 for plants using Dip Proofing Inverters (DPI). Routine Testing and Survey: At all <i>Power Stations</i>. Review items 1 to 3 every 5 to 6 years. Carry out item 5 every 5 to 6 years.</p>
		<p>PURPOSE To confirm that the <i>Power Station</i> and its <i>Auxiliary Supply</i> loads conform to the requirements of supply frequency and voltage magnitude deviations as specified: 1. Frequency: (50+/-1.25)Hz; 2. Voltage: (1+/-0.5) p.u. normal conditions; (1+/-0.1) p.u. abnormal conditions</p>
		<p>SCOPE OF PLANT OR SYSTEMS Critical plant: Equipment or systems that is likely to cause tripping of a <i>Generating Unit</i>, parts of a <i>Unit</i> or that is likely to cause a Multiple Unit Trip (<i>MUT</i>).</p>
		<p>PROCEDURE</p> <ol style="list-style-type: none"> 1. Frequency Deviation Survey: Carry out a survey on the capability of critical plant, confirming that it will resume normal operation for frequency deviations as defined figure 2.2.1.6. Document findings. A <i>Generating Unit</i> or <i>Power Station</i> must not trip or unduly reduce load for system frequency changes in the range specified in 2.2.1.6. 2. Voltage Magnitude Deviation Survey: Carry out a survey on the capability of critical plant confirming that it will resume normal operation for voltage deviations as defined in 2.2.1.6. Document Findings. Also consider <i>Protection</i> and other tripping functions on critical plant. Document all findings. A <i>Generating Unit</i> or <i>Power Station</i> must not trip or unduly reduce load for system voltage changes in the range specified in 2.2.1.6. 3. Dip Proofing Inverter Integrity Testing: <ol style="list-style-type: none"> (a) <i>Generating Unit</i> must be off load. Relevant board isolated and earthed. For outside or central plant, section of plant must be off boards off and isolated. (b) Injection test DPIs according to <i>OEM</i> requirements. <i>DPI</i> must be capable of producing the VA Output and change-over time faster than that specified by the <i>OEM</i>. Every five years on every critical board. (c) Isolate all Drives on the board. (d) Select all drives to manual or local control. (e) Supply an independent AC supply to the input of the <i>DPI</i>. (f) Close the contactors for drives. (g) Subject the <i>DPI</i> supply to an interruption of 0.5 s. (h) Document all results

Parameter	Grid Code Reference	Details
		ACCEPTANCE CRITERIA All contactors must remain closed. Report to be submitted to <i>the System and Market Operator</i> one <i>month</i> after testing. Routine studies, and survey reports to be submitted one <i>month</i> after expiry of due date.

7.17.13. On Load Tap Changing for Generating Unit Step-up Transformers

Parameter	Grid Code Reference	Details
<p align="center">On Load Tap Changing Capability</p>	<p align="center">Sub-Section 7.11</p>	<p>Prototype Test: At new <i>Power Stations</i> coming on line or <i>Power Stations</i> where major modifications to plant that may entail replacement of Step-up Transformers or Tap-changing Equipment have been done</p> <p>Routine Testing: At all <i>Power Stations</i>: during annual maintenance (once every year) or as agreed with the System and Market Operator.</p>
		<p>PURPOSE To prove the <i>Step-up Transformer</i> for each <i>Generating Unit</i> can meet the minimum requirements of the <i>Grid Code</i></p>
		<p>PROCEDURE</p> <ol style="list-style-type: none"> 1. With the Tap-changer Control mode selected to Local Electrical, change the tap position by one step in both the Raise and Lower directions using the Local Control Switch(es). 2. With the Tap-changer Control mode selected to Remote change the tap position by one step in both the Raise and Lower directions using the Remote Control Switch(es) 3. In each case, confirm that the voltage varies in accordance with the tap-changer nameplate data. [NB: checking of voltage variation over the entire tapping range should only be done by injection of a low voltage supply, with the transformer off-load] 4. Insert the manual operation handle and attempt raising or lowering the tap position electrically to check that electrical operation is blocked. 5. Document the results.
		<p>ACCEPTANCE CRITERIA All Step-up Transformer Tap-changers shall be operable from both the Local and Remote locations. Electrical operation shall be blocked with the manual operation handle inserted.</p>

SECTION 8: TECHNICAL REQUIREMENTS FOR UNCONVENTIONAL GENERATORS

8.1. OBJECTIVES

The objective of this Code is to specify minimum technical and design grid connection requirements for Renewable Power Plants (RPPs) and Battery Energy Storage System (BESS) connected to or seeking connection to the Electricity *Transmission System (TS)* or *Distribution System (DS)* in Malawi.

8.2. SCOPE

8.2.1. The grid connection requirements set out in this Code shall apply to SMO, TL, DL, all **RPPs** and **BESS** connected or seeking connection to the *TS* or *DS* to the IPS;

8.2.2. The Code specifies the minimum requirements for the following *RPP* technologies:

- a) Photovoltaic
- b) Concentrated Solar Power
- c) Small Hydro
- d) Biomass
- e) Biogas/ Landfill Gas
- f) Wind

8.2.3. The **BESS** can be connected as a standalone facility or as multiple units operating as modular parallel units forming a large integrated facility. In the latter the facility category is based on the combined nominal active power of the connected units

- a) TL or DL, as the case may be, shall determine the POC of the BESS.
- b) (d) Unless otherwise stated, the requirements in this code shall apply equally to all BESS categories in charging or discharging mode.
- c) Where there has been a replacement of or a major modification to an existing BESS, the BESS shall be required to demonstrate compliance to the requirements of this Code before being allowed to operate commercially.

8.2.4. The Code shall take precedence on matters of Renewable Power Plants and Battery Energy Storage Systems whenever there is a conflict with other *codes*.

8.2.5. Compliance to this Code depends on RPP/BESS's *rated* power and, where indicated, the nominal voltage at the *POC*.

8.2.6. Accordingly, *RPPs and BESS* are grouped into the following three categories of rated power:

- a) Category A: Up to 1 MVA

This category includes *RPPs and BESS* with *rated power* of up to 1 MVA that are connected to the distribution system. This category shall further be divided into 3 sub-categories:

- a.1) **Category A1: up to 20 kVA** : This sub-category includes *RPPs and BESS* of *Category A* with *rated power* up to 20kVA that are connected to the 230 or 400V networks and also even connected to the 11kV or 33KV networks
- a.2) **Category A2: Above 20 kVA up to 100 kVA**: This sub-category includes *RPPs and BESS* of *Category A* with *rated power* in the range greater than 20 kVA and up to 100 kVA that are connected to the 400V and also even connected to the 11kV or 33KV networks

- a.3) **Category A3: Above 100 kVA up to 1 MVA:** This sub-category includes *RPPs* of *Category A* with *rated power* in the range above 100 kVA and up to 1 MVA, typically connected to 11kV or 33kV systems.

Note: *RPPs* with a *rated power* greater than 10kVA must be balanced three-phase.

- b) **Category B: Above 1 MVA and up to 20 MVA :** This category includes *RPPs* with *rated power* in the range greater than 1 MVA and up to 20 MVA.
- c) **Category C: Above 20 MVA:** This category includes *RPPs* with *rated power more than 20MVA*

The *RPP and BESS* shall supply with a reasonable detail of *TS* or *DS* that is sufficient to allow an accurate analysis of the interaction between the *RPP* and the Interconnected Power System (*IPS*), including other *generation facilities*.

8.3. TOLERANCE OF FREQUENCY AND VOLTAGE DEVIATIONS

The *RPP* shall be able to withstand frequency and voltage deviations at the *POC* under normal and abnormal operating conditions that will support the network frequency and voltage stability.

8.4. NORMAL OPERATING CONDITIONS

- 8.4.1. Unless otherwise stated, the requirements shall apply to all *categories* of *RPPs and BESS*.
- 8.4.2. *RPPs and BESS* of *Category A* shall be designed to be capable of operating continuously within the voltage range of -15% to +10% around the nominal voltage at the *POC*.
- 8.4.3. *RPPs and BESS* of *Category B and C* shall be designed to be capable of operating continuously within the *POC* voltage range specified by V_{min} and V_{max} as shown in Table 8.4-1, measured at the *POC*

Table 8.4-1: Minimum and maximum operating voltages at PCC

Nominal (Vn) [kV]	Vmin [pu]	Vmax [pu]
400	0.95	1.05
132	0.90	1.1
66	0.90	1.1
33	0.90	1.1
11	0.90	1.1

- 8.4.4. The nominal frequency of the *IPS* is 50 Hz and is normally controlled within the limits as defined in the *Grid Code*. The *RPP and BESS* shall be designed to be capable of operating for the minimum operating range illustrated in Figure 8.4-1 (total cumulative over the life of the *RPP*) and Figure 8.4-2 (during a system frequency disturbance).

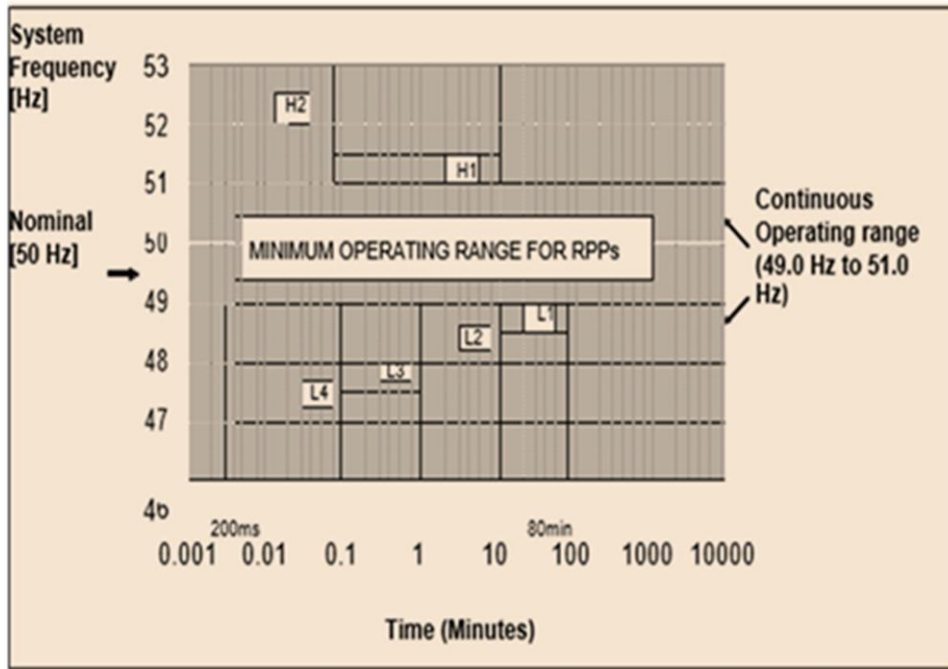


Figure 8.4-1: Minimum frequency operating range for RPP (Cumulative over the life of RPP)

8.4.5. When the frequency on the *IPS* is higher than 51.5 Hz for longer than 8 seconds (see Figure 8.4-2), the *RPP* shall be disconnected from the grid.

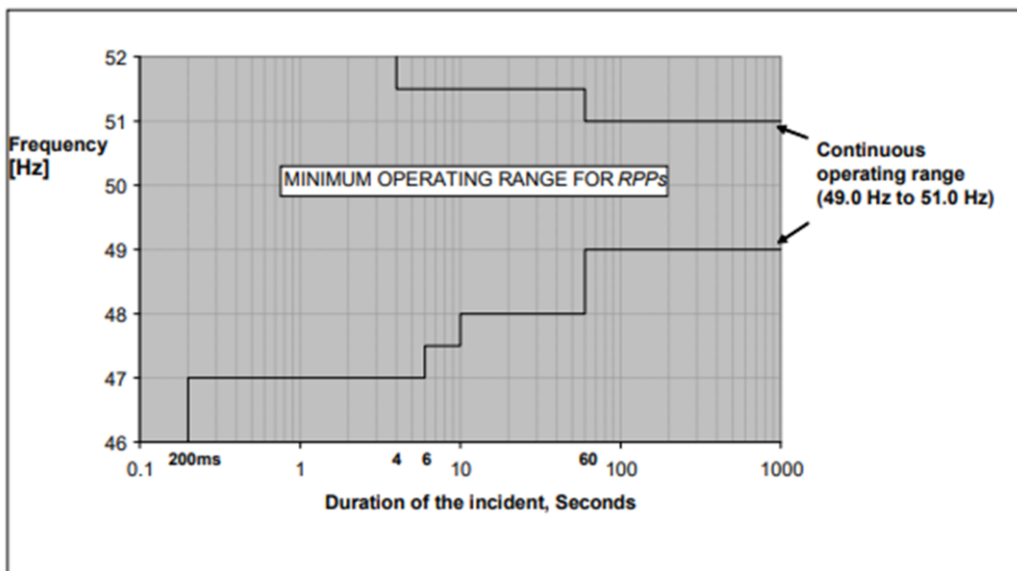


Figure 8.4-2: Minimum frequency range (during a system frequency disturbance)

8.4.6. When the frequency on the *IPS* is less than 47.0 Hz the RPP should be capable of increasing power output. If the frequency is less than 47.0Hz for longer than 4s, the *RPP* may be disconnected (see Figure 8.4-2).

8.4.7. The *RPP* shall remain connected to the *IPS* during rate of change of frequency of values up to and including 1.5 Hz per second, provided the frequency control is within the range of 49 – 51 Hz

8.5. SYNCHRONISING TO THE *IPS*

8.5.1. *RPPs and BESS of Category A* shall only be allowed to connect to the *IPS*, at the earliest, 60 seconds after:

- a) The voltage at the *POC* is in the range -15% to +10% around the *nominal voltage*,
- b) Frequency in the *IPS* is within the range of 49.0Hz and 50.2Hz, or otherwise as agreed with the SMO.

8.5.2. *RPPs and BESS of Category B and C* shall only be allowed to connect to the *IPS*, at the earliest, 3 seconds after:

- a) The voltage at the *POC* is within V_{max} and V_{min} as specified in Table 8.5-1 and Figure 8.6-1, around the *nominal voltage*.
- b) Frequency in the *IPS* is within the range of 49.0Hz and 50.2Hz, or otherwise as agreed with the SMO.

Table 8.5-1: Maximum disconnection times for RPPs of categories A1 and A2

Voltage range (at the POC)	Maximum trip time [Seconds]
$V < 50 \%$	0,2 s
$50 \% \leq V < 85 \%$	2 s
$85 \% \leq V \leq 110 \%$	Continuous operation
$110 \% < V < 120 \%$	2 s
$120 \% \leq V$	0,16 s

8.6. ABNORMAL OPERATING CONDITIONS

Tolerance to phase jump, **BESS** shall be designed to withstand sudden phase jumps not related to system failure of up to 20°. at the POC without disconnecting or reducing its active power output. The BESS shall after a settling period resume normal production not later than 5 sec after the operating conditions in the POC have reverted to the normal operating conditions.

8.6.1. Tolerance To Sudden Voltage Drops and Peaks

- a) RPPs and BESS of Category A1 and A2
Power Plants of Categories A1 and A2 shall be designed to withstand and fulfil, at the PCC, voltage ride through conditions illustrated in Figure 8.6-1

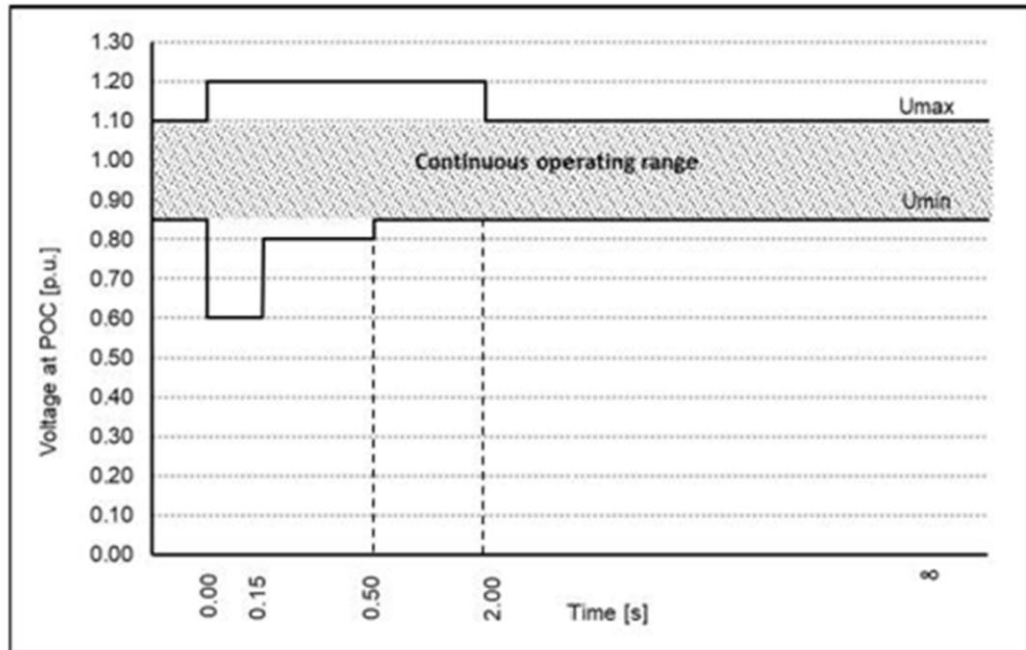


Figure 8.6-1: Voltage Ride Through Capability (A1, A2)

In addition, the maximum disconnection times for *RPPs* of *Category A1 and A2*

8.6.2. In case of Plants on Categories A3, B1, B2 and C

- a) The Plants shall be designed to withstand voltage conditions described in this section and illustrated in Figures 8.6-2 and 8.6-3. Area D applies to category power plants.
- b) The Plants shall be able to withstand voltage drops to zero, measured at the POC, for a minimum period of 0.150 seconds without disconnecting, as shown in Figure 8.6-3.
- c) The Plants of category C shall be able to withstand voltage peaks up to 120% of the nominal voltage, measured at the POC, for a minimum period of 2 seconds without disconnecting, as shown in Figure 8.6-2.
- d) The *RPPs* shall be able to withstand voltage drops to zero, measured at the POC, for a minimum period of 0.150 seconds without disconnecting, as shown in Figure 8.6.2.
- e) Figure 8.6-2 shall apply to all types of faults (symmetrical and asymmetrical i.e. one-, two- or three-phase faults) and the bold line shall represent the minimum voltage of all the phases.
- f) If the voltage (V) reverts to area A during a fault sequence, subsequent voltage drops shall be regarded as a new fault condition. If several successive fault sequences occur within area B and evolve into area C, disconnection is allowed.
- g) In the area C disconnection of the BESS is allowed but is not mandatory.
- h) In connection with symmetrical fault sequences in areas B and D, the power plants shall have the capability of controlling the positive sequence of the reactive current, as illustrated in Figure 8.6-2.

8.6.3. The following requirements shall be complied with:

Area A: The **Plants** shall stay connected to the network and uphold normal production.

Area B: The **Plants** shall stay connected to the network and in addition:

- a) Plants of category A shall not inject any reactive current into the network;

- b) The Plants of category B1, B2 and category C shall provide maximum voltage support by supplying a controlled amount of additional reactive current as shown in Figure 8.6-2 so as to ensure that the BESS contributes to stabilizing the voltage within the design framework offered by the BESS.
- c) BESS and inverter driven RPPs of category B1, B2 and category C shall be able to disable reactive current support functionality at the request of the SMO or the local network operator

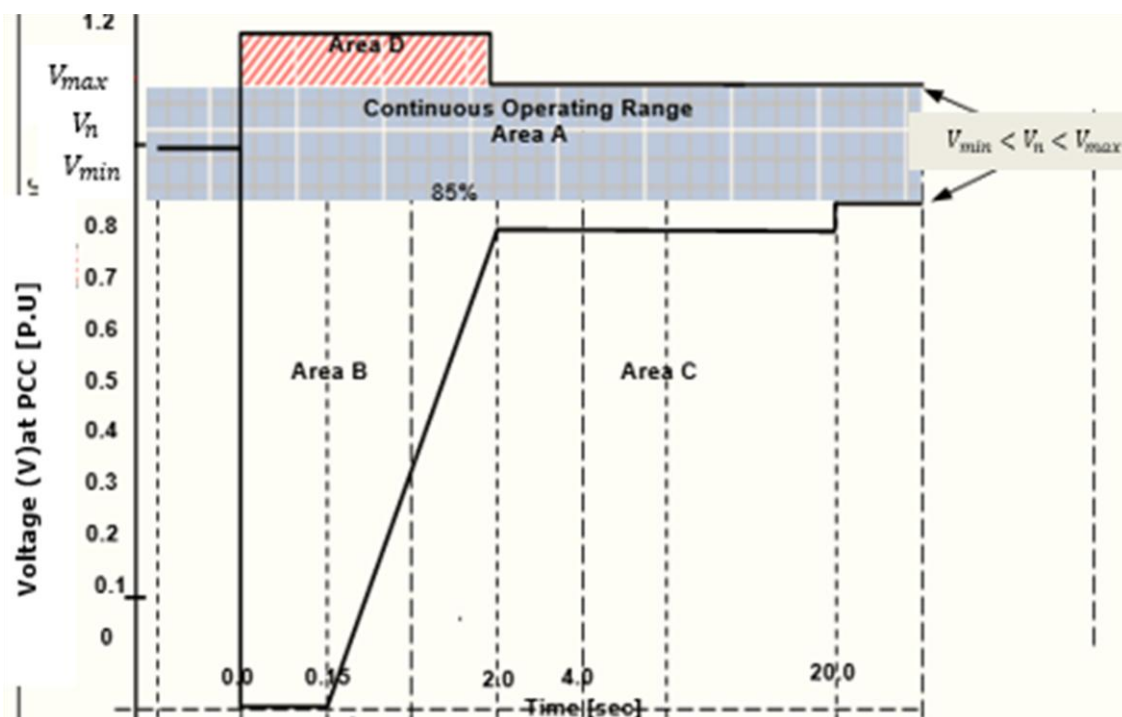


Figure 8.6-2: Voltage Ride Capability for BESS (A3, B1, B2 and C)

- 8.6.4. **Area D:** The BESS shall stay connected to the network and provide maximum voltage support by absorbing a controlled amount of reactive current so as to ensure that the BESS helps to stabilize the voltage within the design capability offered by the BESS. See Figure 8.6-3.
- 8.6.5. **Area E:** Once the voltage at the POC is below 20%, as shown in Figure 8.6-3, the BESS shall continue to supply reactive current within its technical design limitations so as to ensure that the BESS helps to stabilize the voltage. Disconnection is only allowed after conditions of Figure 8.6-2 have been fulfilled.
- 8.6.6. Control shall follow Figure 8.6-3 so that the reactive current follows the control characteristic with a tolerance of $\pm 20\%$ after 60ms.
- 8.6.7. The supply of reactive power has first priority in area B, while the supply of active power has second priority. Active power shall be maintained during voltage drops, but a reduction in active power within the BESS design specifications is required in proportion to voltage drop for voltages below 85%.
- 8.6.8. Upon clearance of fault, each plant shall restore active power production to at least 90% of the level available immediately prior to the fault within 1 second.

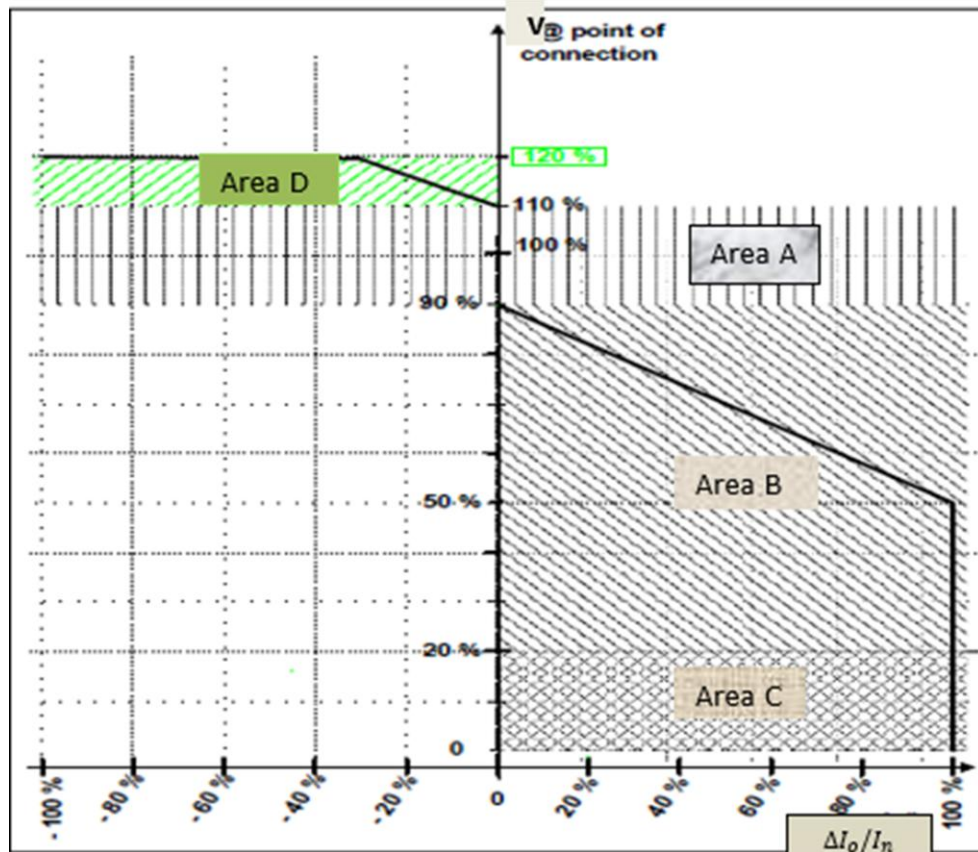


Figure 8.6-3: Requirements for Reactive Current (I_Q) during a voltage failure.

8.7. POWER - FREQUENCY RESPONSE

- In case of frequency deviations in the *IPS*, *PPs* shall be designed to be capable of providing power-frequency response in order to stabilise the grid system *frequency*.
- The type of frequency response applicable to all categories is indicated in Table 8.7-1 below.

Table 8.7-1: Frequency response requirements for *PPs*

	Category A	Category B	Category C
Low frequency, mandatory response	Optional	Required	Required
High frequency, mandatory response	Required	Required	Required

- The metering accuracy for the grid system frequency shall be ± 10 mHz or better.
- It shall be possible to set the frequencies to the default settings for f_{min_max} f_1 to f_6 as shown in Table 8.7-2, unless otherwise agreed upon between the SMO and the *PP* Operators

Table 8.7-2: Frequency Default Settings

PARAMETER	f_{min}	f_{max}	f_0	f_1	f_2	f_3	f_4	f_5	f_6
FREQUENCY (Hz)	47.00	52.00	50.00	47.50	49.5	49.85	50.15	50.50	51.5

- e) The PPs shall, according to category requirement, be equipped with the frequency control droop settings.
- f) The default settings for Droop 1 to Droop 4 shall be as shown in Table 5 below, unless otherwise agreed upon between the SMO and the PPs operator. The actual droop setting shall be as agreed with the SMO.

Table 8.7-3: Droop Default Settings- Low Frequency

Parameter	Droop 1	Droop 2	Droop 3	Droop 4
% of nominal active power capacity	10 %	4 %	4 %	10 %

8.7.2. Power-frequency response curve for **RPPs**

- a) During high *frequency* operating conditions, *RPPs* shall be able to meet a mandatory *active power* reduction requirement in order to stabilise the *frequency* in accordance with Figure 8.8-1 below. The metering accuracy for the grid *frequency* shall be ± 10 mHz or better.
- b) When the *frequency* on the *IPS* exceeds 50.5 Hz, the *RPP* shall reduce the active power as a function of the change in *frequency* as illustrated in Figure 8.7.1 below.
- c) Once the *frequency* exceeds 52Hz for longer than 4 seconds the *RPP* shall be tripped to protect the *IPS*.

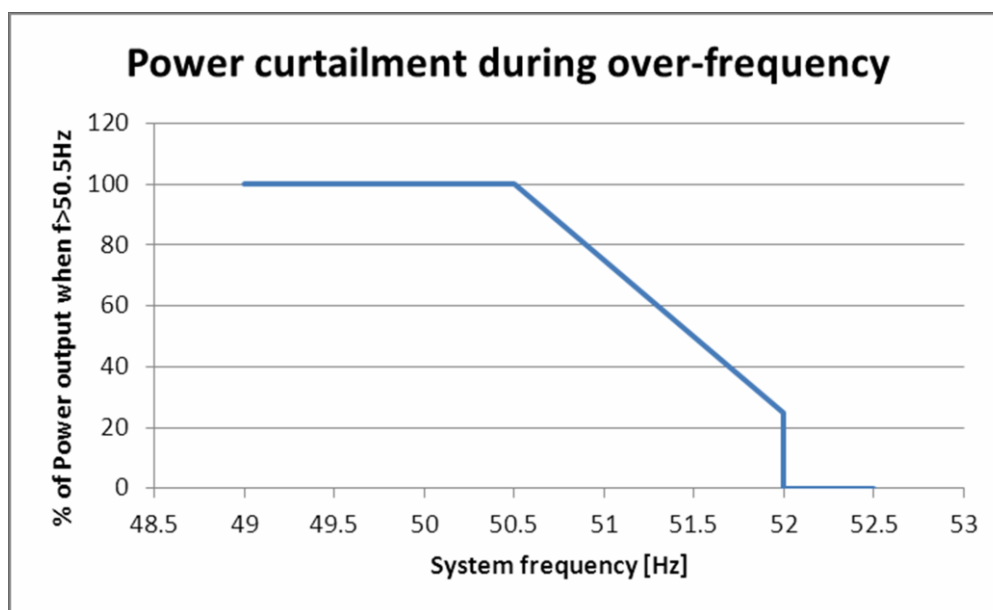


Figure 8.7-1: Power Curtailment during over frequency for RPPs

8.7.3. Power-frequency response curve for RPPs of Category C

- a) *RPPs* shall be designed to be capable of providing power-frequency response as illustrated in Figure 8.7-2.
- b) Except for the mandatory high frequency response (above 50.5 Hz), the *RPP* shall not perform any frequency response function (i.e. there shall be no P_{Δ} , dead-band and control- band functions) without having entered into a specific agreement with the *SMO*.
- c) It shall be possible to set the frequency response control function for all frequency points shown in Figure 8.7-2. It shall be possible to set the frequencies f_{min} , f_{max} , as well as f_1 to f_6 to any value in the range of 47 - 52 Hz with a minimum accuracy of 10 mHz.
- d) The purpose of frequency points f_1 to f_4 is to form a dead band and a control band for *RPPs* contracted for primary frequency response. The purpose of frequency points f_4 to f_6 is to supply mandatory critical power/frequency response.
- e) The *RPP* shall be equipped with the frequency control *droop* settings as illustrated in figure 8.7-2. Each *droop* setting shall be adjustable between 0% and 10%. The actual *droop* setting shall be as agreed with the *SMO*.
- f) The *SMO* shall decide and advise the *RPP generator* (directly or through its agent) on the *droop* settings required to perform control between the various frequency points.
- g) If the active power from the *RPP* is regulated downward below the unit's design limit P_{min} , shutting down of individual *RPP units* is allowed.
- h) The *RPP* (with the exception of *PVPP*) shall be designed with the capability of providing a P_{Δ} of not less than 3% of $P_{available}$. P_{Δ} is the amount of active power by which the available active power has been reduced in order to provide reserves for frequency stabilisation.
- i) It shall be possible to activate and deactivate the frequency response control function in the interval from f_{min} to f_{max} .
- j) The accuracy of the control performed (i.e. change in active power output) and of the set-point shall not deviate by more than $\pm 2\%$ of the set-point value or by $\pm 0.5\%$ of the rated power, depending on which yields the highest tolerance.

8.7.4. Power-frequency response during low frequency for **BESSs** of Category C only

- a) During low frequency (below f_2) operating conditions, BESS shall be able to provide mandatory, instantaneous and autonomous active power response in order to support the frequency in accordance with droop 1 in Figure 8.7.2 below. The metering accuracy for the grid frequency shall be ± 10 mHz or better.
- b) The action taken by the BESS will depend on whether it is in charging or discharging mode. The BESS shall respond as depicted in Figure 8.7-2 as follows to a decreasing system frequency:
 - b.1) While in charging mode, if frequency drops below f_2 , the BESS shall reduce demand and change to discharge mode.
 - b.2) if the system frequency still drops to below f_1 the BESS shall stay connected at least until f_{min} or until the protection is disconnecting the BESS.
 - b.3) While in discharging mode, no decrease in output shall occur. The BESS shall continue discharging and respond according to Droop 1 as per Figure 8.7-2.
 - b.4) The low frequency response can be interrupted when the system frequency is above f_2 or if the BESS discharge level reaches an agreed level according to the connection agreement.

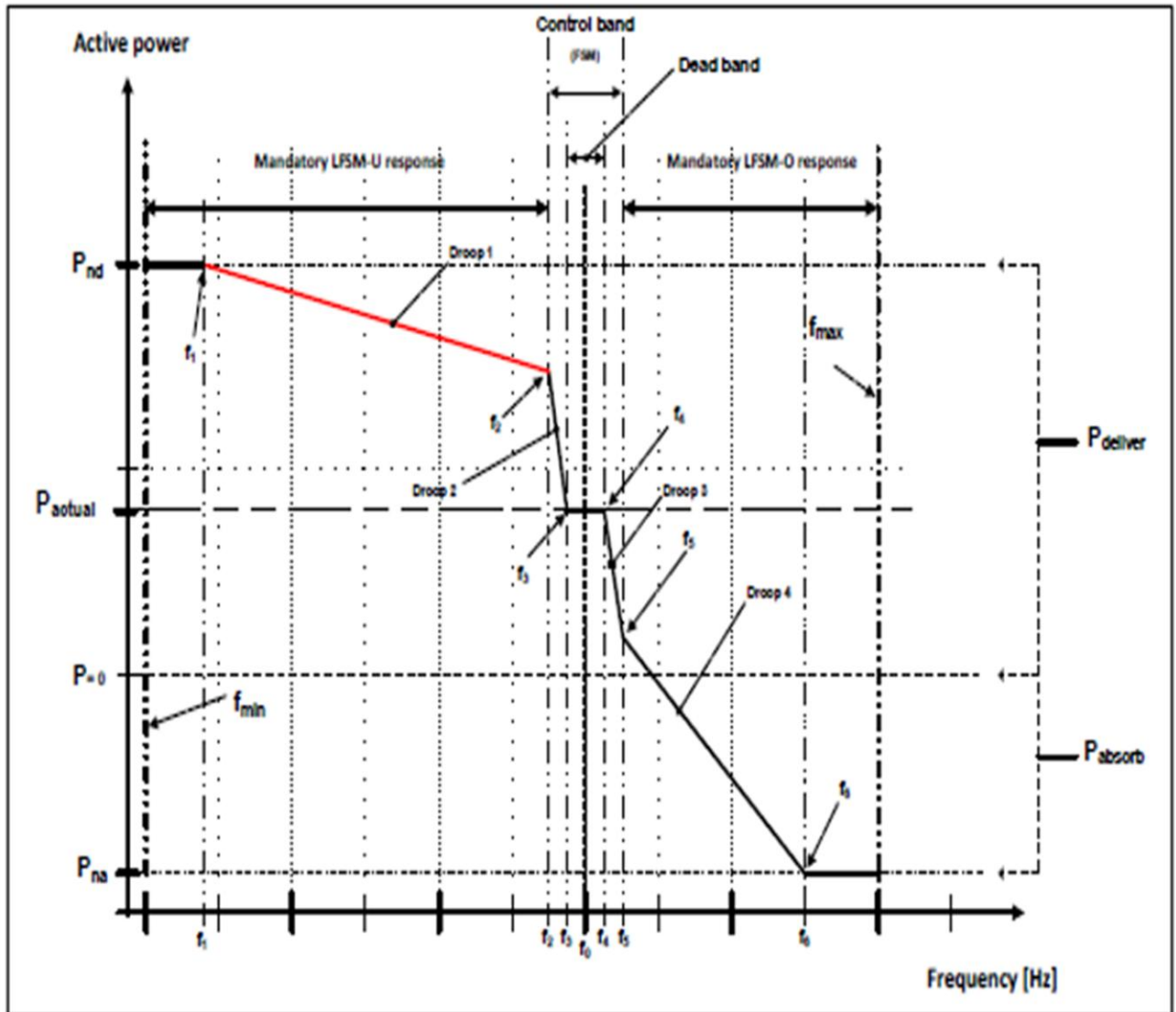


Figure 8.7-2: Power response during low frequency.

8.7.5. Power-frequency response during high frequency for **BESSs**

- a) This section shall apply to BESS of all categories.
- b) During high frequency (above f_5) operating conditions, BESS shall be able to provide mandatory, instantaneous, and autonomous active power response to stabilize the system frequency in accordance with droop 4 in Figure 8.7-3. The action taken by the BESS will depend on whether it is in discharging or charging mode. The BESS shall respond as follows to reduce system frequency:
 - b.1) While in discharging mode, if system frequency increases above f_5 , the BESS shall gradually reduce output and change to charging mode if frequency is still increasing to above f_6 in accordance with Figure 8.7-3.
 - b.2) If the system frequency increases above f_6 the BESS shall remain connected at least until f_{max} or until the protection is disconnecting the BESS.
 - b.3) While in charging mode, no decrease in demand shall occur. The BESS shall continue charging and respond according to droop 4 as per Figure 8.7-3.
 - b.4) The high frequency response can be interrupted when the system frequency is below f_5 or if the BESS charging level reach an agreed level according to the connection agreement. (e.g.100%)

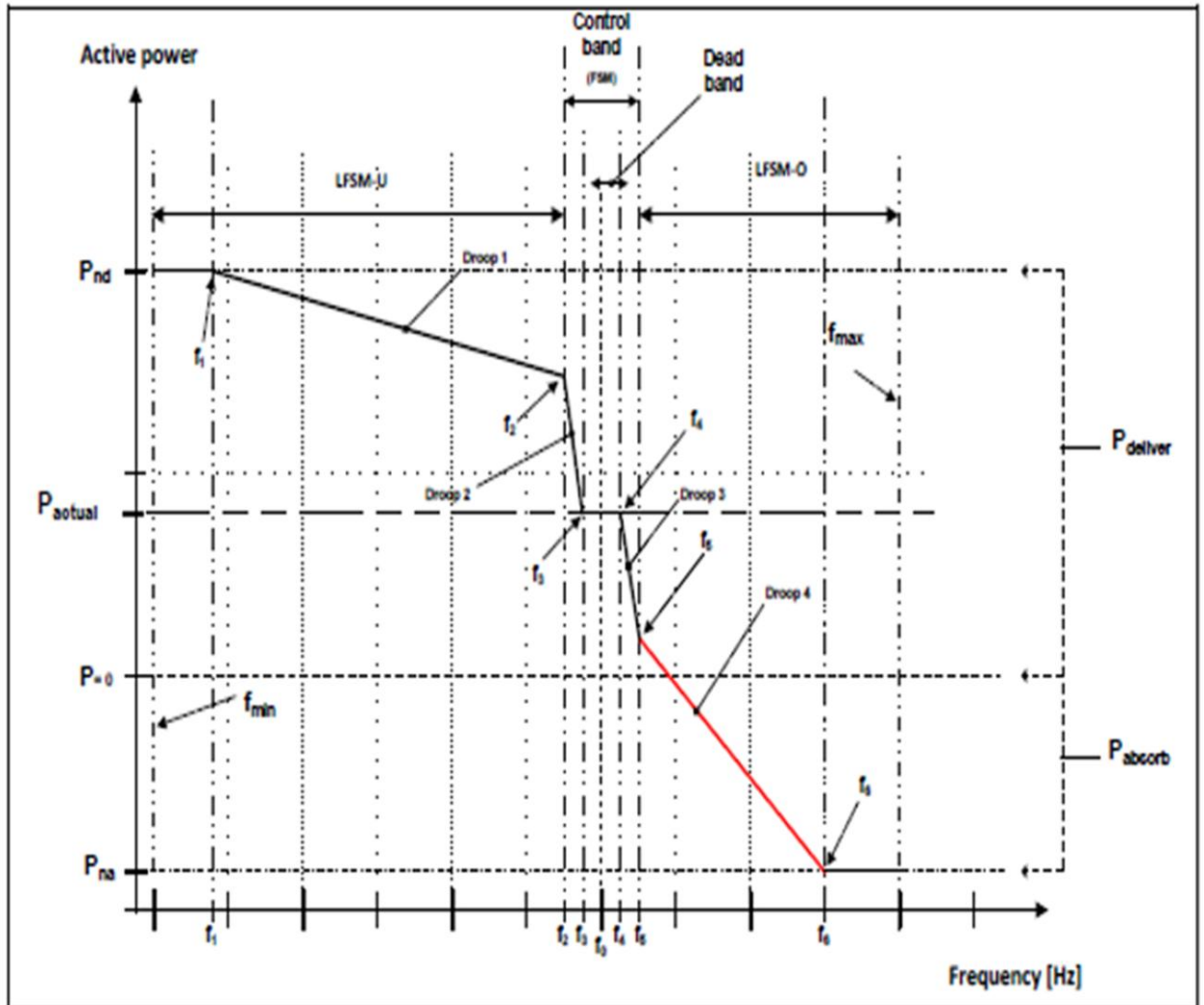


Figure 8.7-3: Power response during high frequency.

8.7.6. Frequency response – Normal/ Contracted Frequency Range

- BESS of categories B1, B2 and C, shall be capable of providing power-frequency response as illustrated with droop 2 and droop 3 in Figure 8.7-4.
- The purpose of the frequency points f_2 and f_5 is to form the control band (Frequency Sensitive Mode - FSM). In addition, the frequency points f_2 and f_5 identify the frequency threshold below and above the control band where the autonomous low and high frequency response is required.
- The purpose of the frequency points f_3 and f_4 is to form the dead band within the control band
- The SMO shall decide and advise the BESS Operator on the droop settings required to perform control between the various frequency points.
- It shall be possible to activate and deactivate the frequency response control function between f_{min} to f_{max} .
- If a frequency control parameter ($f_1 - f_6$) is to be changed as instructed by SMO, such change shall be commenced within two seconds and completed no later than 10 seconds after receipt of an order to change the parameter.
- The accuracy of the control performed (i.e. change in active power output) and of setpoints shall not deviate by more than $\pm 2\%$ of the setpoint value or by $\pm 0.5\%$ of the rated power, depending on which one yields the highest tolerance.

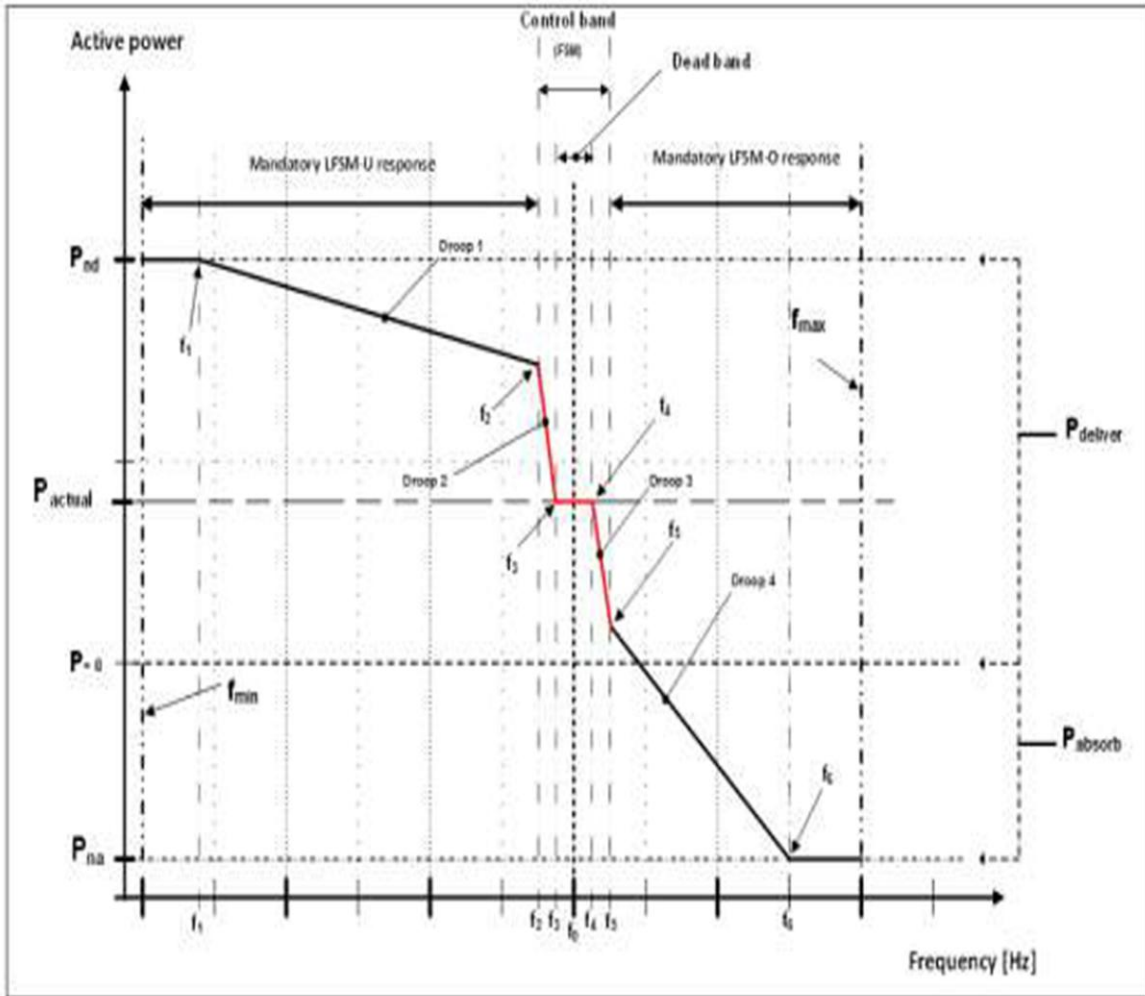


Figure 8.7-4: Power response during normal frequency range

8.8. ACTIVE POWER CONSTRAINT FUNCTIONS

8.8.1. This section shall apply to BESS of categories A3, B1, B2 & C

- a) A BESS must be equipped with control functions capable of controlling the active power at the POC in discharging and charging modes.
- b) For system security reasons it may be necessary for the SMO, DL to curtail the BESS active power output or input whilst in discharging or charging mode.
- c) The BESS shall in discharging or charging modes be capable of:
 - d) Operating at a reduced level if active power has been curtailed by the SMO, DL for network or system security reasons,
 - e) receiving a remotely controlled and monitored MW Curtailment set-point sent from the SMO, DL.
 - f) The BESS shall be equipped with constraint functions, i.e. supplementary active power control functions. The constraint functions are used to avoid imbalances in the IPS or overloading of the TS and DS.
 - g) Activation of the active power constraint functions shall be agreed with the SMO or DL. The required constraint functions are as follows:
 - g.1) Absolute Production Constraint

- (i) An Absolute Production Constraint is used to constrain the output of active power from the BESS to a predefined power MW limit at the POC.
- (ii) If the setpoint for the Absolute Production Constraint is to be changed, the BESS shall commence such change within two (2) seconds and the change shall be completed not later than thirty (30) seconds after receipt of an order to change the setpoint.
- (iii) The accuracy of the control performed and of the setpoint shall not deviate by more than $\pm 2\%$ of the setpoint value or by $\pm 0.5\%$ of the rated power, depending on which yields the highest tolerance, average over a 1-minute interval.

g.2) Power Gradient Constraint

- (i) A Power Gradient Constraint (ramp rate) is used to limit the maximum speed by which the active power can be changed in the event of changes in power or in the set points for a BESS.
- (ii) It shall be possible to set the upward and downward ramp rate limits to any value between 1 to 20 % of P_{nd} or P_{na} per minute. The actual ramp rate shall be specified and agreed by the SMO.
- (iii) The accuracy of the control performed and of the setpoint shall not deviate by more than $\pm 2\%$ of the setpoint value or by $\pm 0.5\%$ of the rated power, depending on which yields the highest tolerance, average over a 1-minute interval.

8.9. PROCEDURE FOR SETTING AND CHANGING THE POWER-FREQUENCY RESPONSE CURVES FOR *RPPs* OF *CATEGORIES C*

The SMO shall give the *RPP generator* a minimum of 2 weeks' notice if changes to any of the frequency response parameters (i.e. f_1 to f_6) are required. The *RPP generator* shall confirm with the SMO or its agent that requested changes have been implemented within two weeks of receiving the SMO's request.

8.9.1. Reactive Power Capabilities RPP Of Category A

- a) The PPs of category A1 & A2 shall operate at unity power factor measured at the POC, unless otherwise specified by Distribution or Transmission licensees.
- b) The PPs of category A3 shall be designed with the capability to supply *rated power* (P_{nd}) and P_{na} (MW) for power factors ranging between 0.95 lagging and 0.95 leading, measured at the POC available from 20% to 100% of *rated power* (P_{nd} / P_{na}).
- c) The RPP shall be designed to operate according to a power factor characteristic curve, which will be determined by the *Distribution licensee*.
- d) The default power factor setting shall be **unity** power factor, unless otherwise specified by the *distribution licensee*
- e) When the BESS of category A is disconnected or is not delivering or absorbing any active power, no compensation of reactive power is required from the BESS.

8.9.2. Reactive Power Capabilities RPPs of Category B

- a) RPPs of category B shall be designed with the capability to operate in a voltage (V), power factor or reactive power (Q or Mvar) control modes as described in section 8.9.3 below. The actual operating mode (V, power factor or Q control) as well as the operating point shall be agreed with the Distribution Licensee.
- b) When operating between 5% and 100% of rated power P_n (MW) the RPP of category B shall have the capability of varying reactive power (Mvar) support at the POC within the reactive power capability ranges as defined by Figure 8.9-1, where Q_{mind} Q_{maxe} voltage dependent as defined by Figure 8.9-4.
- c) At nominal voltage, the required RPP reactive power capability (measured at the POC) shall be as shown in Figure 8.9-3.

- d) When operating below 5% of rated power P_n (MW), there is no reactive power capability requirement, however the RPP can only operate within the reactive power tolerance range not exceeding $\pm 5\%$ of rated power; that is within Area A,B,C and D in Figure 8.9-3.

8.9.3. Reactive Power Capabilities BESS of Category B and C

- a) BESS of category B and C shall be capable of varying their reactive power output at the POC continuously within the operating area ABCDEF shown in Figure 8.9-2, where Q_{min} and Q_{max} voltage dependent as defined by Figure 8.9-5. The voltage ranges V_{min} to V_{max} are defined in section 4.1.
- b) For BESS of category B, $Q_{min} = (-0.228) \times (P_{na} | P_{nd})$ and $Q_{max} = (0.228) \times (P_{nd} | P_{na})$. At rated active power, P_{nd} and P_{na} [MW], this corresponds to a power factor range of 0.975 leading to 0.975 lagging.
- c) For BESS of category C, $Q_{min} = (-0.33) \times (P_{na} | P_{nd})$ and $Q_{max} = (0.33) \times (P_{nd} | P_{na})$. At rated active power, P_{nd} and P_{na} [MW], this corresponds to a power factor range of 0.95 leading to 0.95 lagging.
- d) The continuous operating area may be further constrained by the specified minimum stable active power, which could be above the line AF in Figure 8.9-2.
- e) If the BESS of category B and C is not producing active power, or if the active power level is below 5% of rated active power, the reactive power must be within a tolerance of $\pm 5\%$ of rated power; that is within Area AFGH in figure 8.9.2

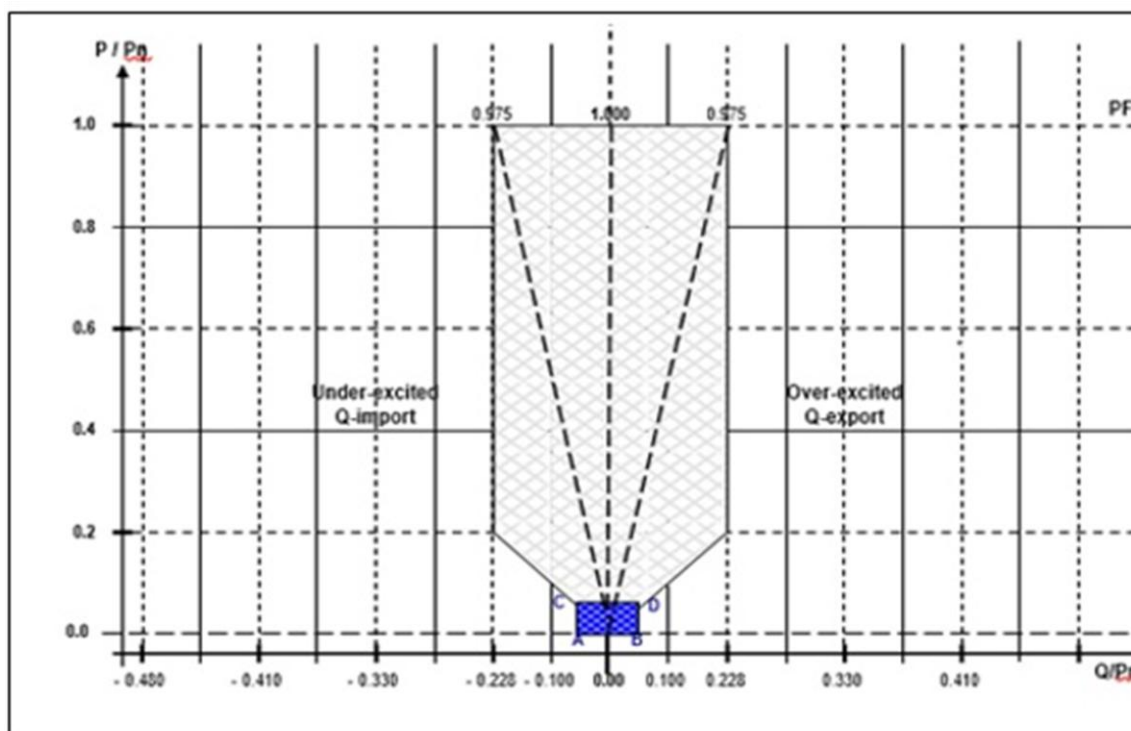


Figure 8.9-1: Reactive Power requirements for RPPs of category B at the PCC (Q_{min} and Q_{max}) are voltage dependent by figure 8.9-3

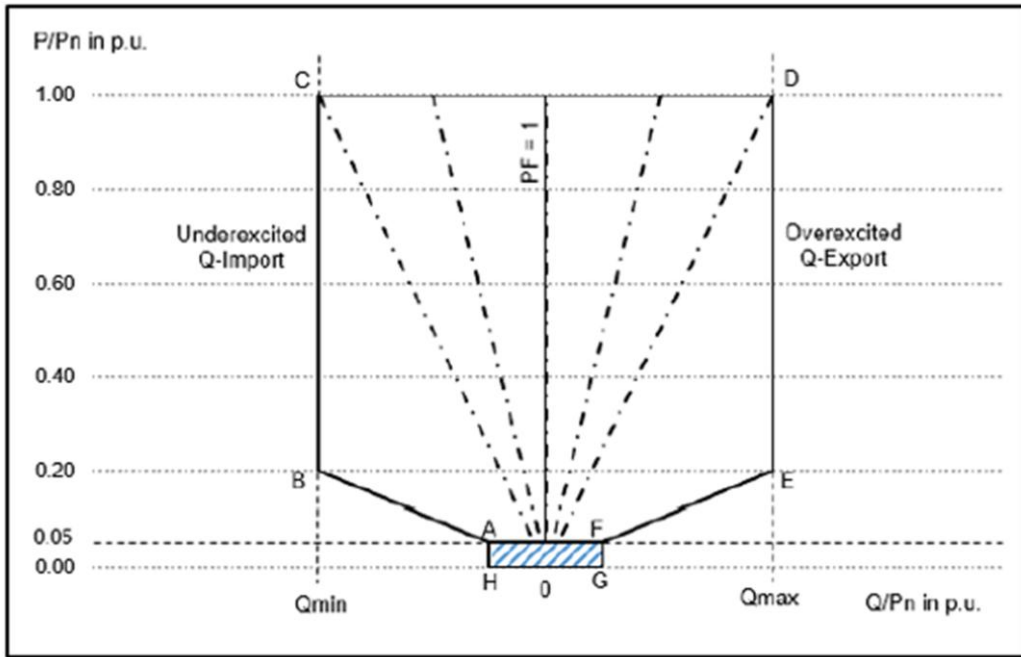


Figure 8.9-2: Reactive Power capability for BESS of Categories B and C at PCC

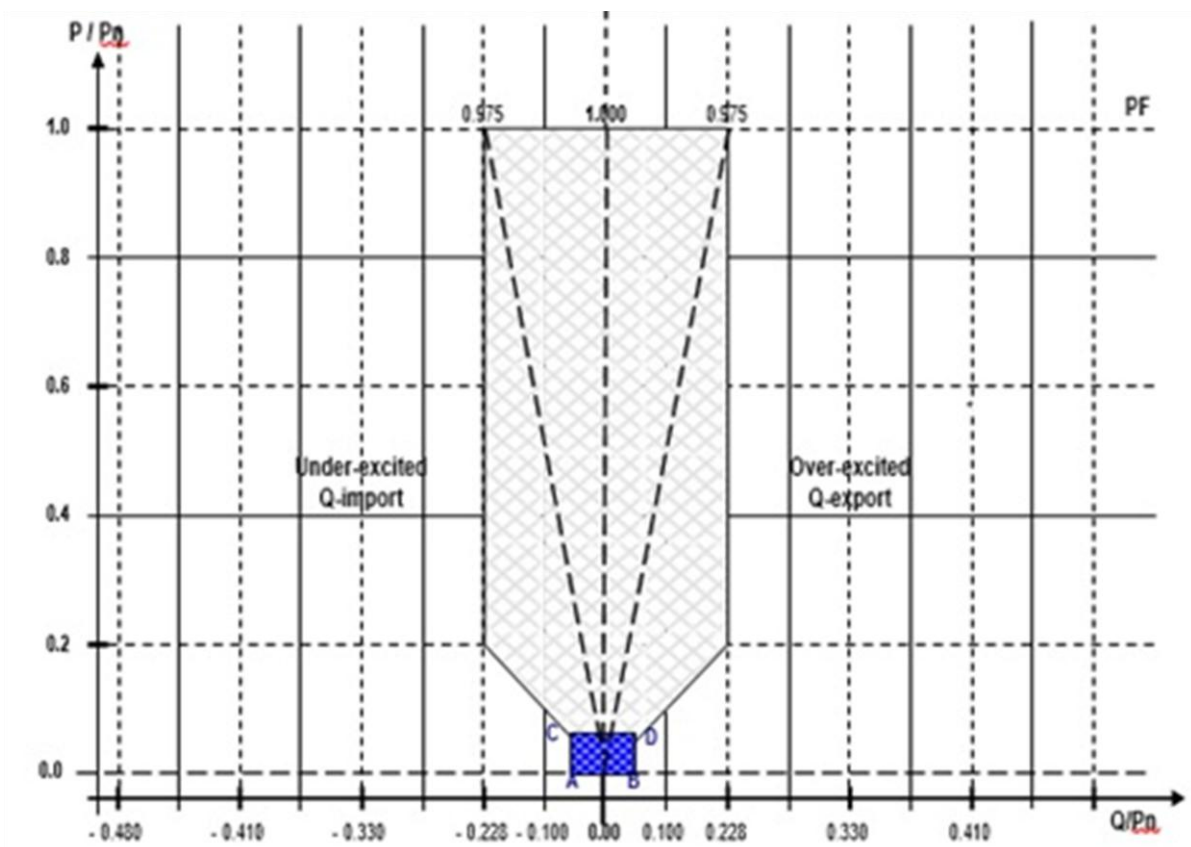


Figure 8.9-3: Reactive power requirements for RPPs of category B at nominal Voltage at PCC

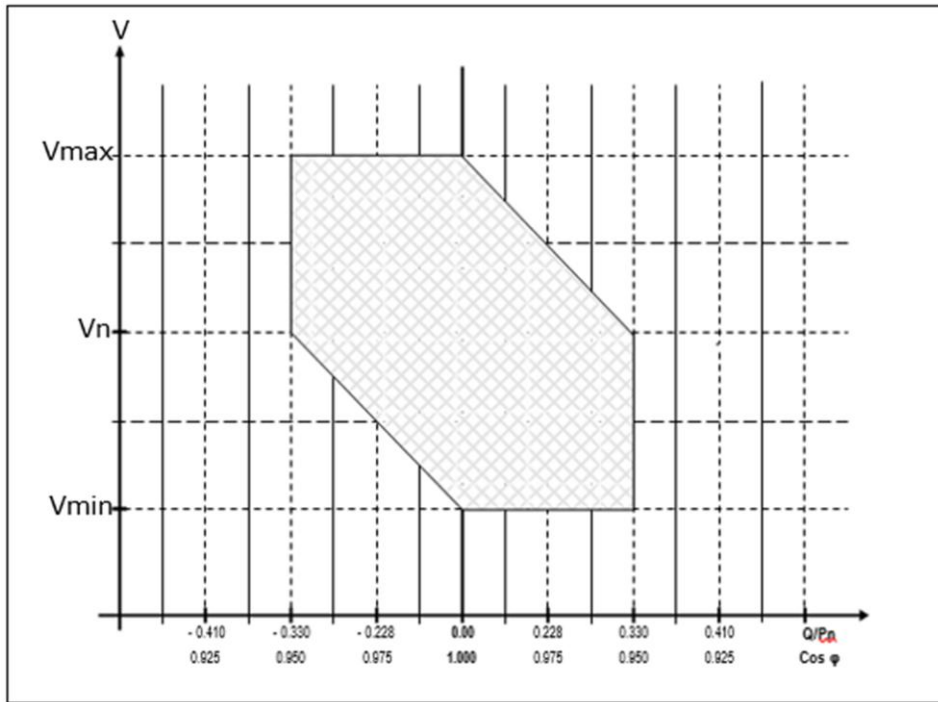


Figure 8.9-4: Requirements for reactive power and voltage control range for RPPS of category B.

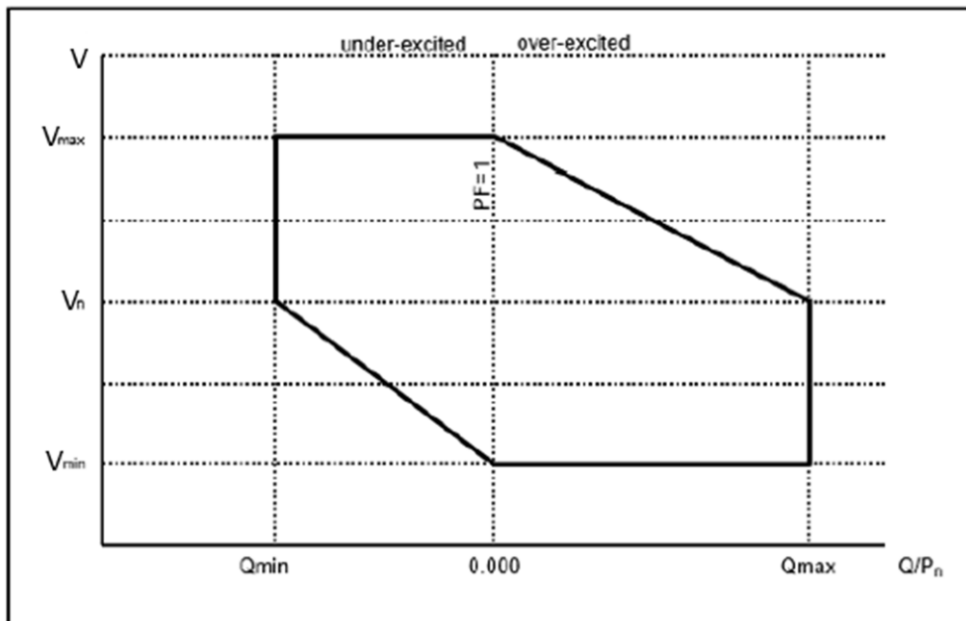


Figure 8.9-5: Voltage dependence of Reactive power capability for BESS of categories B and C at POC

8.10. RPPs OF CATEGORY C

- RPPs of category C shall be designed with the capability to operate in voltage, power factor or, reactive power (Q or Mvar) control modes. The actual control operating mode (V, power factor or Q control) as well as operating point shall be agreed with the SMO.
- When operating between 5% and 100% of *rated power* P_n (MW) the RPP of category C shall have the capability of varying reactive power (MVar) support at the POC within the reactive power capability ranges as defined by Figure 10a, where Q_{min} and Q_{max} voltage dependent as defined by Figure 8.10-4.
- At nominal voltage, the required RPP reactive power capability (measured at the POC) shall be as shown in Figure 8.10-2.
- When operating below 5% of *rated power* P_n (MW), there is no reactive power capability requirement, however the RPP can only operate within the reactive power tolerance range not exceeding $\pm 5\%$ of *rated power*; that is within Area A,B,C and D in Figure 8.10-2.

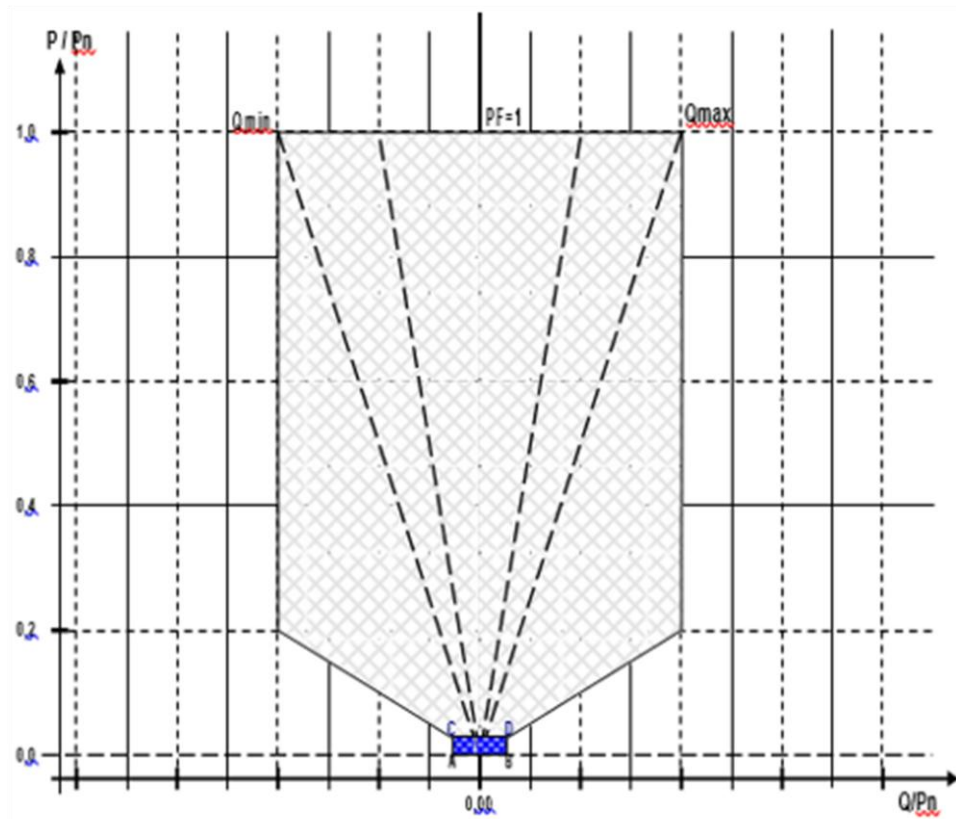


Figure 8.10-1: Reactive power requirements for RPPs of category C at the PCC (Q_{min} and Q_{max}) are voltage dependent as defined by figure 8.10-3

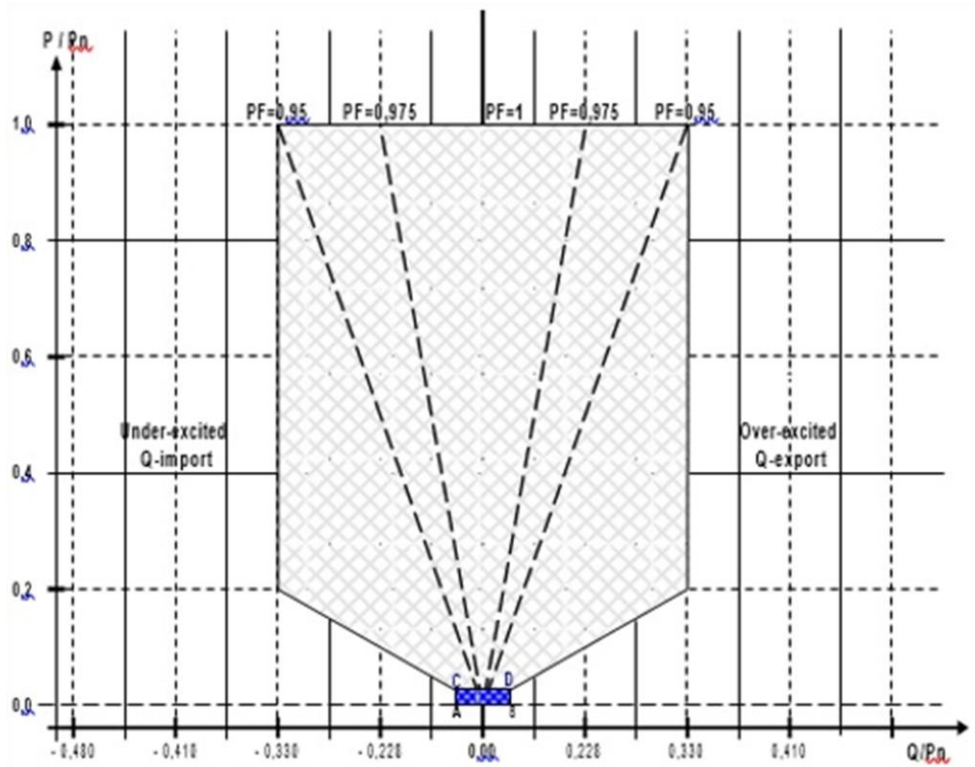


Figure 8.10-2 Reactive power requirements for RPPs of category C (at nominal voltage at POC)

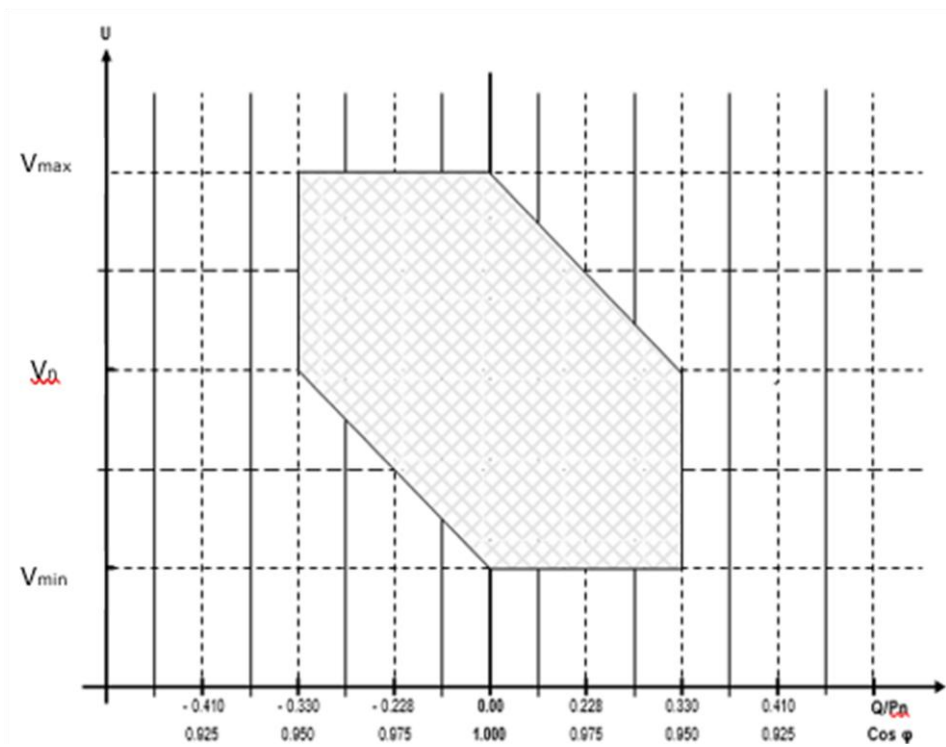


Figure 8.10-4: Requirements for reactive power and voltage control range for RPPs of category C

8.11. REACTIVE POWER AND VOLTAGE CONTROL FUNCTIONS

The following requirements shall apply to *PPs* of category *B* and *C*.

- 8.11.1. The *PP* shall be equipped with reactive power control functions capable of controlling the reactive power supplied by the *RPP* at the *POC* as well as a voltage control function capable of controlling the voltage at the *POC* via orders using setpoints and gradients.
- 8.11.2. The reactive power and voltage control functions are mutually exclusive, which means that only one of the three functions mentioned below can be activated at a time.
- Voltage control
 - Power Factor control
 - Q control
- 8.11.3. The reactive power capabilities are specified at the *POC* unless otherwise specified by the *SMO*
- 8.11.4. The control function and applied parameter settings for reactive power and voltage control functions shall be determined by the *TL* in collaboration with the *SMO* and implemented by the *RPP* generator. The agreed control functions shall be documented in the operating agreement.
- 8.11.5. Unless otherwise agreed with the *SMO*, *TL* or *DL*, *BESS* of categories *A3*, *B* and *C* shall be equipped with remote control facilities according to Table 8.11.1 below

Table 8.11-1: Automatic Reactive power and Voltage Control Functions for all *TS* or *DS* – connected to *BESS*

Category \ Functions	A1	A2	A3	B1	B2	C
Power factor control	-	-	X	X	X	X
Reactive power control	-	-	-	X	X	X
Voltage control	-	-	-	X	X	X
Remote control capability	-	-	X	X	X	X

8.12. REACTIVE POWER (Q) CONTROL

- 8.12.1. Q control is a control function controlling the reactive power supply and absorption at the *POC* independently of the active power and the voltage. This control function is illustrated in **Figure 8.12-1** as a vertical line.
- 8.12.2. The accuracy of the control performed and of the setpoint shall not deviate by more than $\pm 2\%$ of the setpoint value or by $\pm 0.5\%$ of maximum reactive power, depending on which yields the better accuracy. The accuracy shall be measured as a deviation of the actual reactive power from the required reactive power, as a percentage of the maximum required reactive power
- 8.12.3. The *RPP* shall be able to receive a Q setpoint with an accuracy of accuracy of 1kVar or less.

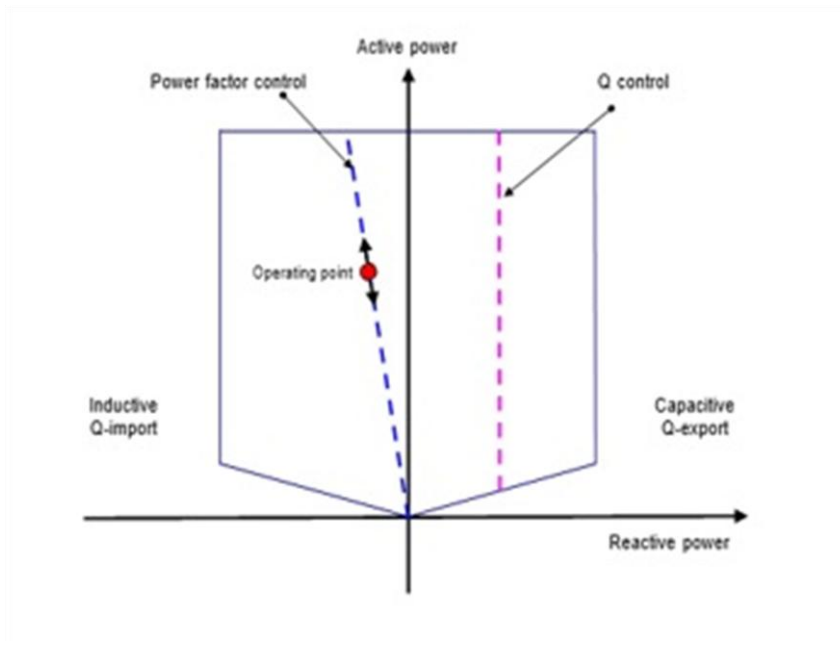


Figure 8.12-1: Reactive power control functions for the RPP.

8.12.4. The response time shall be adjustable. Unless otherwise specified by the SMO and agreed with the BESS operator, TL, DL, the settling time, following a small disturbance, shall be in the range of 10 to 30s.

8.13. POWER FACTOR CONTROL

8.13.1. Power Factor Control for RPP

- Power factor control is a control function controlling the reactive power proportionally to the active power at the POC. This is illustrated in **Figure 8.12-1** by a line with a constant gradient.
- The accuracy of the control performed and of the setpoint shall not deviate by more than ± 0.02 .

8.13.2. Power factor control for BESS

- BESS shall receive the power factor setpoint from the SMO, or DL. The setpoint determines the required power factor at the POC.
- Category A3 Power Plants shall be operated at unity power factor at the POC, unless otherwise specified by SMO, TL or DL.
- Following a small disturbance, the BESS shall change its reactive power output so that the actual power factor equals the power factor setpoint within $\pm 2\%$. The accuracy shall be measured as a deviation of the actual reactive power from the required reactive power (at the required power factor), as a percentage of the maximum required reactive power.
- The response time shall be adjustable. Unless otherwise specified by the SMO and agreed with the BESS operator, TL, DL, the settling time, following a small disturbance, shall be in the range of 10 to 30s.

8.14. VOLTAGE CONTROL

8.14.1. Voltage control for RPPs is a control function controlling the voltage at the POC.

- If the voltage setpoint is to be changed, such change shall be commenced within two seconds and completed no later than 30 seconds after receipt of an order to change the setpoint.

- b) The accuracy of the voltage set point shall be within $\pm 0.5\%$ of nominal voltage, and the accuracy of the control performed shall not deviate by more than $\pm 2\%$ of the required injection or absorption of reactive power according to *droop* characteristics as defined in **Figure 8.14-1**
- c) The individual *RPP* shall be able to perform the control within its dynamic range and voltage limit with the *droop* configured as shown in **Figure 8.14-1**. In this context, *droop* is the voltage change (p.u.) caused by a change in reactive power (p.u.).
- d) When the voltage control has reached the *RPP*'s dynamic design limits, the control function shall await possible overall control from the tap changer or other voltage control functions.
- e) Overall voltage coordination shall be handled by the *Transmission licensee* in collaboration with the *SMO*.

8.14.1. Voltage control for *BESSs* is a control function controlling the voltage at the *POC*.

- a) The *BESS* of categories B and C shall receive the voltage setpoint and the voltage droop setpoint from the *SMO* or *DL*.
- b) *BESS* of categories B and C shall be capable of automatic voltage control according to a droop function, as shown in Figure 10, within its reactive power capability range. In this context, droop is the voltage change (p.u.) caused by a change in reactive power (p.u.).
- c) Following a disturbance, the *BESS* shall change its reactive power so that the voltage equals the required voltage, as per the voltage setpoint and droop setpoint, within $\pm 0.2\%$. The accuracy shall be measured as a deviation between the actual voltage and the required voltage, as a percentage of the rated voltage. Unless otherwise agreed with the *SMO* or *DL*, the settling time shall be in the range of 10 to 30s

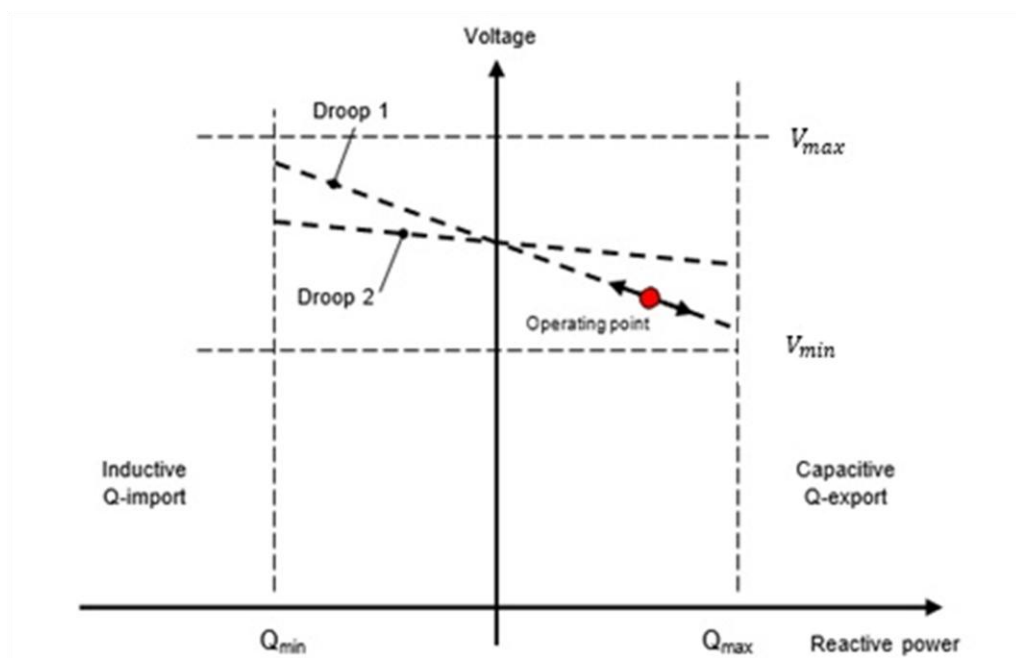


Figure 8.14-1: Voltage control for the Unconventional power plants.

8.15. POWER QUALITY

8.15.1. *Power quality* and voltage regulation impact shall be monitored at the *POC* and shall include an assessment of the impact on *power quality* from the *RPP* concerning the disturbances at the *POC* provided under GCR 5.1

8.15.2. Any attempt by the *RPP* to change the supply frequency may result in severe distortion of the voltage at the *POC*, *PCC* and other points in the network.

- 8.15.3. Voltage and current quality distortion levels emitted by the *RPP* at the *POC* shall not exceed the apportioned limits as determined by the relevant *TL*. The calculation of these emission levels shall be based on international and local specifications. The allocation shall be fair and transparent.
- 8.15.4. The *RPP generator* shall ensure that the *RPP* is designed, configured, and implemented in such a way that the specified emission limit values are not exceeded.
- 8.15.5. Voltage changes under normal operating conditions shall be limited according to the values provided in **Table 8.15-1**. These limits apply at the full range of fault levels at the *POC* of the *RPP* where full generation is possible.

Table 8.15-1: Maximum voltage change permitted at different voltage levels as a function of the frequency of these voltage changes.

Number of Changes per hour r	Percentage Change in the Value	
	Nominal Voltage at POC ($< 44kV$)	Nominal Voltage at POC ($> 44kV$)
$r < 1$	4	3
$1 < r \leq 10$	3	2.5
$10 < r \leq 100$	2	1.5
$100 < r \leq 1000$	1.25	1

8.15.6. For BESS of categories A and B1

- the power converters' harmonic current emissions and their total harmonic distortion (measured in accordance with relevant Malawi Standards) shall not exceed the limits shown in Table 7.
- the voltage fluctuation and flicker shall not exceed the limits specified in MS1260-3-3 (for equipment rated less than or equal to 16 A per phase) and in MS1260-3-5 (for equipment rated greater than 16 A per phase).

Table 8.15-2: Harmonic Current Limits for Power Converters of Categories A and B1 BESS

Harmonic Order	$3 \leq h < 9$	$11 \leq h < 15$	$(17 \leq h < 21)$	$(23 \leq h < 33)$	$(33 \leq h \leq 50)$	Even	THD
Percentage of rated current (odd harmonics)	<4.0	<2.0	<1.5	<0.6	<0.3	25% of odd harmonics	<5.0

8.15.7. For Categories B2 and C -BESS

- The categories B2 shall not cause voltage and current emissions at the POC to exceed the apportioned emission limits specified by the TL or DL.
- The TL and DL shall determine the apportioned emission levels based on a fair and transparent process, in accordance with international and local standards.
- The current harmonic emissions at individual harmonic orders may exceed the apportioned limits by up to 50%, provided that the group harmonic distortion levels are within the limits shown in Table 8.15-3, where h is the harmonic order.

Table 8.15-3: Harmonic Distortion Limits for BESS of Categories B2 and C

Harmonic distortion band	Harmonic order band	Group harmonic current distortion limit
A	$2 \leq h \leq 13$	$[(HD)]_{(IlimitA)} = \sqrt{\sum_{h=2}^{13} (I_{limit}(h))^2}$
B	$14 \leq h < 25$	$[(HD)]_{(IlimitB)} = \sqrt{\sum_{h=14}^{25} (I_{limit}(h))^2}$
C	$26 \leq h \leq 39$	$[(HD)]_{(IlimitC)} = \sqrt{\sum_{h=26}^{39} (I_{limit}(h))^2}$
D	$40 \leq h \leq 50$	$[(HD)]_{(IlimitA)} = \sqrt{\sum_{h=40}^{50} (I_{limit}(h))^2}$

- d) For grid code compliance the BESS shall monitor and report on power quality using an MS1260-4-30 Class A power quality monitoring device. The reporting will be done to prove compliance at the POC against the TL and DL requirements specified in the system supply agreements. The power quality parameters to be reported on must at least include:
- d.1) flicker
 - d.2) harmonics
 - d.3) unbalanced voltages
- e) MERA shall provide guidance to BESS Operators on a method to prove compliance to the Power Quality requirements as set out by the TL or DL.
- f) The BESS Operator shall ensure that the BESS is designed, configured and implemented in such a way that the specified emission limit values are not exceeded

8.15.8. The network harmonic impedance at point of connection shall not exceed $Z(h)$ of :-

$$Z(h) = 3h V^2/s$$

Where

$Z(h)$ is the harmonic impedance

h is the harmonic number

V is the nominal voltage in kV, and

S is the fault level in MVA

- a) For *RPP* impedance at the *POC* will be less than three (3) times the base harmonic impedance for the range of reference fault levels at the *POC*. *The angle of the network harmonic impedance may range from fully inductive to fully capacitive.*
- b) The BESS shall not cause the impedance at the POC to exceed the limit $Z(h)$, as defined above. This limit applies for all frequencies up to the 50th harmonic and for all typical network operating conditions.

The angle of the network harmonic impedance may range from fully inductive to fully capacitive.

8.15.9. In order to assist with the maximum resonance of 3 times as per clause (8.15.8a) above, no *RPP* may connect equipment, e.g. shunt capacitor banks, that will cause a resonance of more than 3 times at the *POC* at any frequency. If this condition can't be met, then an agreement between the *RPP* and Transmission Licensee shall be made.

8.15.10. The *TL* or *DL* shall use their reasonable endeavours to furnish the *RPP* with a reliable and continuous connection for the delivery of electrical energy up to the *POC*.

-
- 8.15.11. The SMO do not guarantee that the continuity and voltage quality of the connection will always be maintained under all contingencies.
- 8.15.12. It is therefore incumbent upon the *RPP* to take adequate measures to protect the *RPP* Facility against any losses and/or damage arising from
- a) frequency deviations,
 - b) connection/supply interruptions,
 - c) voltage variations (including voltage dips),
 - d) voltage harmonics, interharmonics,
 - e) voltage flicker,
 - f) voltage unbalance,
 - g) voltage swells and transients,
 - h) undervoltages and overvoltages in the connection.
- 8.15.13. It is also incumbent upon the *RPP* to take such necessary measures so as not to cause any damage to the *TS and DS*.

8.16. PROTECTION AND FAULT LEVELS

Unless otherwise stated, requirements in this section apply to all *categories*.

- 8.16.1. Protection functions shall be available to protect the *generators* and to ensure a stable *TS* and *DS*.
- 8.16.2. The *generator* shall ensure that *generators are* dimensioned and equipped with the necessary protection functions so that the *RPP* is protected against damage due to faults and incidents in the *TS* and *DS*.
- 8.16.3. Protection for internal BESS faults shall not jeopardize Voltage Ride Through Capabilities
- 8.16.4. The *RPP of Category A* shall be equipped with effective detection of islanded operation in all system configurations and the capability to shut down generation of power in such condition within 0.2 seconds. Islanded operation with part of the *TS* or *DS* is not permitted unless specifically agreed with the *SMO*.
- 8.16.5. The *RPP of Category B* and *C* shall be equipped with effective detection of islanded operation in all system configurations and capability to shut down generation of power in such condition within 2 seconds. Islanded operation with part of the *TS* or *DS* is not permitted unless specifically agreed with the *SMO*.
- 8.16.6. The BESS of all categories shall be equipped with an effective Loss of Mains (LOM) detection, functional in all system configuration and operation modes and capability to shut down generation of power in such condition within 2 seconds. Unintended BESS islanded operation with part of the *TS* or *DS* is not permitted unless specifically agreed with the *SMO, TL, DL*. Vector shift relay as detection scheme is prohibited.
- 8.16.7. The *SMO, TL or DL may* request that the set values for protection functions be changed following commissioning if it is deemed to be of importance to the operation of the *TS* and *DS*. However, such change shall not result in the *RPP* being exposed to negative impacts from the *TS* and *DS* lying outside of the design requirements.
- 8.16.8. The *TL or DL* shall inform the *RPP generator* of the highest and lowest short-circuit current that can be expected at the *POC* as well as any other information about the *TS* and *DS* as may be necessary to define the *RPP's* protection functions.

8.17. ACTIVE POWER CONSTRAINT FUNCTIONS

This section shall apply to *RPPs of categories A3, B & C*

8.17.1. For system security reasons it may be necessary for the *SMO* to curtail the *RPP* active power output.

8.17.2. The *RPP generator* shall be capable of:

- a) operating the *RPP* at a reduced level if active power has been curtailed by the *SMO* for network or system security reasons.
- b) receiving a telemetered *MW Curtailment set point* sent from the *SMO*. When another operator is implementing power curtailment, this shall be in agreement with all the parties involved.

8.17.3. The *RPP* shall be equipped with constraint functions, i.e. supplementary active power control functions. The constraint functions are used to avoid imbalances in the *IPS* or overloading of the *TS* and *DS* in connection with the reconfiguration of the *TS* and *DS* in critical or unstable situations or the like, as illustrated in **Figure 8.17.1**

8.17.4. Activation of the active power constraint functions shall be agreed with the *SMO*. The required constraint functions are as follows:

- a) An Absolute Production Constraint is used to constrain the output active power from the *RPP* to a predefined power MW limit at the *POC*. This is typically used to protect the *TS* and *DS* against overloading.
- b) A Delta Production Constraint is used to constrain the active power from the *RPP* to a required constant value in proportion to the possible active power. Delta Production Constraint is typically used to establish a control reserve for control purposes in connection with *frequency control*
- c) A Power Gradient Constraint is used to limit the maximum ramp rates by which the active power can be changed in the event of changes in primary renewable energy supply or the setpoints for the *RPP*, taking into account the availability of primary energy to support these gradients. A Power Gradient Constraint is typically used for reasons of system operation to prevent changes in active power from impacting the stability of the *TS* or the *DS*.

8.17.5. If the setpoint for the Absolute Production Constraint is to be changed, such change shall be commenced within two seconds and completed not later than 30 seconds after receipt of an order to change the setpoint.

8.17.6. The accuracy of the control performed and of the setpoint shall not deviate by more than $\pm 2\%$ of the setpoint value or by $\pm 0.5\%$ of the *rated power*, depending on which yields the highest tolerance.

8.17.7. If the setpoint for the Delta Production Constraint is to be changed, such change shall be commenced within two seconds and completed no later than 30 seconds after receipt of an order to change the setpoint.

8.17.8. The accuracy of the control performed and of the setpoint shall not deviate by more than $\pm 2\%$ of the setpoint value or by $\pm 0.5\%$ of the *rated power*, depending on which yields the highest tolerance.

8.17.9. If the setpoint for the Power Gradient Constraint is to be changed, such change shall be commenced within two seconds and completed no later than 30 seconds after receipt of an order to change the setpoint.

8.17.10. The accuracy of the control performed and of the setpoint shall not deviate by more than $\pm 2\%$ of the setpoint value or by $\pm 0.5\%$ of the *rated power*, depending on which yields the highest tolerance.

8.17.11. The active power constraint functions are illustrated on **Figure 18.17-1**

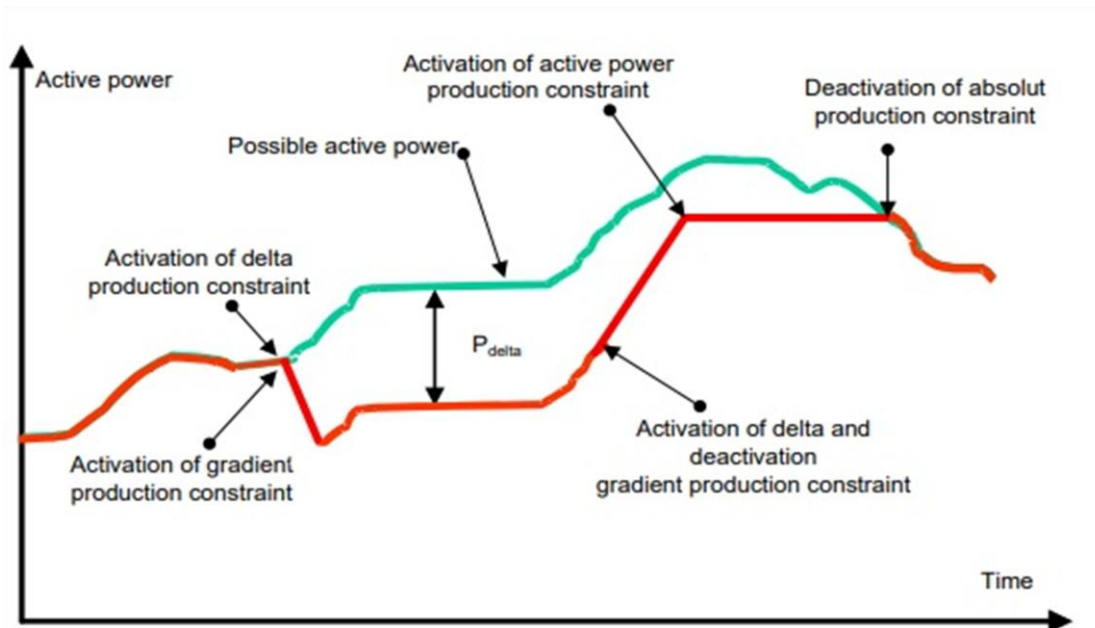


Figure 8.17-1: Active power control functions for a Renewable Power Plant

8.18. CONTROL FUNCTION REQUIREMENTS

- 8.18.1. *RPPs* shall be equipped with the control functions specified in **Table 8.18.1**. The purpose of the various control functions is to ensure overall control and monitoring of the *RPP's* generation.
- 8.18.2. The *RPP* control system shall be capable of controlling the ramp rate of its active power output with a maximum MW per minute ramp rate set by *SMO* or *TL*.
- 8.18.3. These ramp rate settings shall be applicable for all ranges of operation including positive ramp rate during start up, positive ramp rate only during normal operation and negative ramp rate during controlled shut down. They shall not apply to frequency regulation.
- 8.18.4. The *RPP generator* shall not perform any frequency response or voltage control functions without having entered into a specific agreement to this effect with the *SMO*
- 8.18.5. The specifications and regulation functions specified shall comply with the international standard IEC 61724

Table 8.18-1: Control functions required for RPPs

Control function	Category A3	Category B	Category C
Frequency control		-	X
Absolute production constraint	X	X	X
Delta production constraint	-	-	X
Power gradient constraint	X	X	X
Q control	-	X	X
Power factor control	-	X	X
Voltage control	-	X	X

8.19. SIGNALS, COMMUNICATIONS & CONTROL

- 8.19.1. All signals shall be made available at the POC by the RPP generator.
- 8.19.2. Requirements for the exchange of signals between RPPs of category A and the SMO shall be limited to start and stop signals.
- 8.19.3. Requirements for the exchange of signals between RPPs of Category B and C, and, SMO are described in the following sections.
- 8.19.4. In case of BESS the supervisory control and Data Acquisition Availability applies to all categories
- The signals specified in Table 8.19-1 must be exchanged between parties at the Point of Communication (PCOM) interface to control and monitor a BESS facility
 - The signals indicated are the minimum requirement that the BESS operator must provide per category; additional site-specific signals may also agreed with SMO, TL or DL.
 - All digital signals reported to the Gateway shall be time-stamped (GMT +2:00) to an accuracy of +/-1 millisecond and shall be reported within 1 second of any change.
 - All control signals sent from SMO or DL to the BESS must have an acknowledgement returned to the SMO TL or DL as per applicable protocol in section 11.
 - Timestamps on analogue changes are not required.
 - All analogue input changes shall be reported to the Gateway within 1 second of any change greater than or equal to the following:
 - Frequency shall be updated when the value changes by 0.01 Hz or more.
 - Power factor values shall be updated when the value changes by 0.01 or more.
 - Active power values shall be updated when the value changes by 1 % or more of rated power. If rated power is 50 MW or more then values shall be updated when the value changes by 0.5 MW or more.
 - Actual Ramp Rate shall be updated when the value changes by 1 MW/min or more.
 - All other analogues shall be updated when the value changes by 1% or more of the full-scale or nominal value.
- 8.19.5. Signals to be made available at the POC includes the following

Table 8.19-2:Signal Minimum requirements

	Description	Criteria	Category									
			C	B2	B1	B1 MV	B1 MV own use	A3 MV	A3 MV Own Use	A3 LV	A2	A1
1	Actual Active Power Export/Produce (+) Import/Absorb (-) at POC	MV or kW	x	x	x	x	x		x			
2	Actual ramp rate of entire Power Plant Power Gradient Constraint ramp rate	MW/min	X	x	x	X			x			
3	Actual Reactive Power Export/Produce (+) Import/Absorb (-) at POC	-/+ MVar	X	X	x	x			x			
4.	Reactive power range upper and lower limits for RPP	MVAR	X	X	x	x			x			
5	Actual power current export / import (A)	Amps/Phase	x	x	x	x			x			
6	Voltage measured at point of connection	Volts/Phase	x	x	x	x			x			
7	BESS POC breaker status (a per network owner specifications)	Open/closed	x	x	x	x			x			
8	BES plant in shutdown mode	Yes/no	x	x	x	x			x			
9	Frequency at POC	Hz	x	x	x	x						

	Description	Criteria	Category																	
10	Frequency response mode status for frequency support	On/off	x	x	x	x														
11	Power factor at POC	Cos (Phi)	x	x	x	x														
12	Curtailement mode status - Absolute Power Control	On/off	x	x	x	x														
13	Curtailement mode status - Absolute Power Control limiter	MW	x	x	x	x														
14	Active Power gradient constraint mode (P)	On/off	x	x	x	x														
15	Active Power gradient Up Ramp rate setpoint feedback	MW/min	x	x	x	x														
16	Active Power gradient Down Ramp rate setpoint feedback	MW/min	x	x	x	x														
17	Reactive power control mode (Q)	On/off	x	x	x	x														
18	Reactive power control setpoint feedback	MVar	x	x	x	x														
21	Power Factor control mode (PF)	On/off	x	x	x	x														
22	Power factor control setpoint	Cos (Phi)	x	x	x	x														
23	Voltage control mode (V)	On/off	x	x	x	x														
24	Voltage control setpoint -raise or lower value	Volts	x	x	x	x														
25	Voltage control setpoint feedback	Volts	x	x	x	x														
26	Voltage output		x	x	x	x														
27	Echo MW set point		x	x	x	x														
28	Echo Mvar set point		x	x	x	x														
29	Echo Voltage set point		x	x	x	x														

8.19.6. *RPP generator* shall make available estimates on SCADA signals for SMO designated *communication gateway equipment* located at the *RPP* site:

- a) Available MW and forecast MW for the next 6 hours updated hourly on the hour.
- b) Available range of MVar capability for the next 6 hours updated hourly on the hour.

8.19.7. The *RPP generator* shall make the following signals available for MW Curtailment at a designated *communication gateway equipment* located at the *RPP* site:

- a) *RPP* MW Curtailment facility status indication (ON/OFF) as a double bit point. This is a controllable point which is set on or off by the *SMO*. When set "On" the *RPP* shall then clarify and initiate the curtailment based on the curtailment set point value below.
- b) Curtailment in progress digital feedback. This single bit point will be set high by the *RPP* while the facility is in the process of curtailing its output.
- c) *RPP* MW Curtailment Set-point value (MW- feedback).

8.19.8. In the event of a curtailment, the *SMO* will pulse the curtailment set point value down. The *RPP* response to the changed curtailment value will be echoed by changing the corresponding echo MW value. This will provide feedback that the *RPP* is responding to the curtailment request.

8.19.9. The *RPP generator* shall make *Frequency Response System* mode status indication (ON/OFF) as a double bit point for the signals to be made available at an SMO designated *communication gateway equipment* located at the *RPP* site:

- a) *RPP generator* shall make the following signals available on *RPP* Meteorological Data at a *SMO* or *TL* designated *communication gateway equipment* located at the *RPP* site:
- b) Wind speed (within 75% of the hub height) – measured signal in meters/second (for *WPP* only)
- c) Wind direction within 75% of the hub height) – measured signal in degrees from true north(0-359) (for *WPP* only)

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- d) Air temperature- measured signal in degrees centigrade (-20 to 50);
 - e) Air pressure- measured signal in millibar (800 to 1400).
 - f) Air density (for *WPP only*)
 - g) Solar radiation (for *PVPP only*)
- 8.19.10. The meteorological data signals shall be provided by a dedicated Meteorological Mast located at the *RPP* site or, where possible and preferable to do so, data from a means of the same or better accuracy.
- 8.19.11. Energy resource conversion data for the facility (e.g. MW/ solar radiation) for the various resource inputs to enable the *SMO* to derive a graph of the full range of the facilities output capabilities. An update will be sent to the *SMO* following any changes in the output capability of the facility
- 8.19.12. For an *RPP* where the *units* are widely dispersed over a large geographical area and rather different weather patterns are expected for different sections of the *RPP*, the meteorological data shall be provided from a number of individual Meteorological Masts, or where possible and preferable to do so, data from a source of the same or better reliability for groups of *units*. It is expected that *units* within an individual group shall demonstrate a high degree of correlation in Active Power output at any given time. The actual signals required shall be specified by the *SMO*. There shall be at least one Meteorological Mast for every 10x10 square km area of the facility
- 8.19.13. Signals shall be updated at the following rates:
- a) Analog Signals at a rate of 2 seconds.
 - b) Digital Signals at the rate of 1 second.
 - c) Meteorological data once a minute
- 8.19.14. The control signals shall be sent from *SMO* to the *RPP*. And shall be capable of receiving these signals and acting accordingly.
- a) An Active-Power Control set-point signal shall be sent by *SMO* to the *RPP* control system. This set-point shall define the maximum Active Power output permitted from the *RPP*. The *RPP* control system shall be capable of receiving this signal and acting accordingly to achieve the desired change in Active Power output.
 - b) This value is controlled by raise or lower pulses.
 - c) The *RPP generator* shall make it possible for the *SMO* to remotely enable/disable the Active-Power control function in the *RPP* control system.
- 8.19.15. A facility shall be provided by *Market the Participant* to facilitate the disconnection of the *RPP*. It shall be possible for *SMO* to send a trip signal to the circuit breaker at the *HV* side of the *POC*.

8.20. MW FORECAST

- 8.20.1. The *RPP generator* of *category B* and *C* shall have the capability to produce and submit to the *SMO* the day- ahead and week-ahead hourly MW production forecast.
- 8.20.2. The forecasts shall be provided by *RPP generator* of *category B* and *C*. These forecasts shall be provided by 10:00 a.m. on a daily basis for the following 24 hours and 7 days for each 1 hour time-period, by means of an electronic interface in accordance with the reasonable requirements of *SMO's* data system.
- 8.20.3. The *RPP generator* shall submit *RPP MW* availability declarations whenever changes in MW availability occur or are predicted to occur. These declarations shall be submitted by means of an electronic interface in accordance with the requirements of *SMO's* data system.

8.21. DATA COMMUNICATIONS SPECIFICATIONS

- 8.21.1. The *RPP* shall have external *communication gateway equipment* that can communicate with a minimum of three simultaneous SCADA Masters, independently from what is done inside the *RPP*.
- 8.21.2. The location of the communication gateway equipment shall be agreed between affected participants in the connection agreement
- 8.21.3. The necessary communications links, communications protocol and the requirement for analogue or digital signals shall be specified by the *SMO* as appropriate before a *connection agreement* is signed between the *RPP generator* and DL or TL.
- 8.21.4. Active Power Curtailment or Voltage Regulation facilities at the *RPP* shall be tested once every 6 months. It is essential that facilities exist to allow the testing of the functionality without tripping the actual equipment.
- 8.21.5. Where signals or indications required to be provided by the *RPP generator* become unavailable or do not comply with applicable standards due to failure of the *RPP* equipment or any other reason under the control of the *RPP*, the *RPP generator* shall restore or correct the signals and/or indications within a time agreed with the *SMO* or any *market participant*

8.22. TESTING AND COMPLIANCE MONITORING

- 8.22.1. All *facilities* shall demonstrate compliance to all applicable requirements and any other applicable *code*, before being allowed to connect to the *DS* or the *TS*.
- 8.22.2. The *facility* shall demonstrate compliance through the provision of design information, study reports, test reports and as-built documentation.
- 8.22.3. The *facility* shall conduct tests or studies to demonstrate that the *RPP* complies with each of the requirements of this RPP Code.
- 8.22.4. For BESS of categories A1 and A2 the owner and manufacturer's declaration of compliance as well as independent testing can be used to demonstrate compliance.
- 8.22.5. The *facility* shall continuously monitor its compliance in all material respects with all the connection conditions of this RPP Code.
- 8.22.6. Each *generator or facility* shall submit to the *SMO* a detailed test procedure, emphasising system impact, for each relevant part of this RPP Code prior to every test.
- 8.22.7. If the *RPP generator* determines, from tests or otherwise, that the *RPP* is not complying with one or more sections of this RPP Code, then the *RPP Generator* shall (within 24 hours of being aware):
 - a) notify the *SMO* of that fact
 - b) advise the *SMO* of the remedial steps it proposes to take to ensure that the relevant *RPP* can comply with this RPP Code and the proposed timetable for implementing those steps
 - c) diligently take such remedial action to ensure that the relevant *RPP* can comply with this RPP Code; the *RPP generator* shall regularly report in writing to the *SMO* on its progress in implementing the remedial action, and
 - d) after taking remedial action as described above, demonstrate to the reasonable satisfaction of the *SMO* that the relevant *RPP* is then complying with this RPP Code.
- 8.22.8. The *SMO* may issue an instruction requiring the *RPP generator* to carry out a test to demonstrate that the relevant *RPP* complies with the Grid Code requirements. An *RPP generator* may not refuse such an instruction, provided it is issued timeously and there are reasonable grounds for suspecting non-compliance.

8.22.9. The BESS operator shall keep records relating to the compliance of of this code, or any other code applicable, setting out such information that the SMO or responsible TL or DL reasonably requires for assessing power system performance, including actual BESS performance during abnormal conditions.

8.22.10. Studies and Tests

- a) BESS operator shall perform simulation studies and tests, including those listed in Table 12, to demonstrate compliance with this Code.
- b) Simulation studies shall be based on validated models of the BESS. BESS operator shall provide evidence of the validity of the simulation models.
- c) Each BESS Operator of Category A3 and above shall submit to the SMO, TL or DL a detailed test procedure, emphasizing system impact, for each relevant part of this code prior to every test.
- d) The continuous monitoring of compliance shall be in line with the procedures of the "routine" studies and tests described in Table 8.22-1.
- e) The scope of the studies and tests that are required following a plant modification shall depend on which requirements are affected by the modification and shall be agreed with the SMO and either TL or DL.
- f) The SMO, TL or DL may provide additional guidelines about the execution of simulation studies and tests.

Table 8.22-1: Minimum Set of Studies and Tests per BESS Category

	Study or test	BESS Category
8.22-1	<u>Active Power Capability and Associated Control</u>	
a)	Simulation study showing frequency response capability and performance	Where function is required
b)	Test demonstrating frequency response capability and performance	Where function is required
c)	Test demonstrating absolute power constraint function	Where function is required
d)	Test demonstrating delta power constraint function	Where function is required
f)	Test demonstrating power gradient function	Where function is required
8.22-2	<u>Reactive power capability and associated control (Q, Pf and V)</u>	
a)	Simulation study showing reactive power capability and performance	A3, B and C,
b)	Test showing control capability and performance	A3, B and C,
8.22-3	<u>Tolerance of Voltage Deviations</u>	
	Simulation study showing voltage response capability and performance	A3, B and C,
8.22.-4	<u>Power Quality</u>	
	Simulation study showing power quality performance	B2 and C,
	Tests showing power quality performance	B2 and C,
8.22-5	<u>Protection</u>	
a)	Study on protection functions and settings	A, B and C,
b)	Tests showing correct operation of all protection and synchronisation functions	A, B and C,

8.23. NON-COMPLIANCE DETERMINED BY THE BESS OPERATOR

8.23.1. If a BESS Operator determines, from tests or otherwise, that its BESS is not complying in any respect with one or more sections of this Code, then the BESS Operator shall:

-
- a) notify the SMO, TL or DL of that fact within one hour after becoming aware of the noncompliance,
 - b) promptly advise the SMO, TL or DL of the remedial steps it proposes to take to ensure that the relevant BESS (as applicable) can comply with this code and the proposed timetable for implementing those steps
 - c) diligently take such remedial action as will ensure that the relevant BESS (as applicable) can comply with this code; the BESS Operator shall regularly report in writing to the SMO, TL or DL on its progress in implementing the remedial action, and
 - d) after taking remedial action as described above, demonstrate to the satisfaction of the SMO, TL or DL that the relevant BESS (as applicable) is then complying with this code.

8.24. NON-COMPLIANCE SUSPECTED BY THE SYSTEM AND MARKET OPERATOR

8.24.1. If at any time the SMO, TL or DL suspects that a BESS is not complying with a requirement in this code, then the SMO TL or DL shall notify the relevant BESS operator of such noncompliance by issuing a non-conformance report (as provided in section 4.2.4 of the Grid Code), specifying the requirement concerned and the basis for the SMO's or TL/DL's suspicion.

- a) The SMO, TL or DL shall specify the remedial action required from the BESS operator as well as the time frames within which to comply with this code.
- b) Any dispute arising out of such a non-conformance report shall be resolved in terms of the dispute resolution procedure described in the Governance Code.
- c) The SMO, TL or DL may issue an instruction requiring a BESS operator to carry out a test to demonstrate that the relevant BESS complies with the Grid Code requirements. A BESS operator may not refuse such an instruction, provided it is issued timeously and there are reasonable grounds for suspecting non-compliance.

8.25. UNIT MODIFICATIONS

8.25.1. Modification proposals

- a) If a Generator proposes to change or modify any of its Units in a manner that could reasonably be expected to either adversely affect that Unit's ability to comply with this Code, or changes its performance, Information supplied, settings, etc., then the Generator shall submit a proposal notice to the System and Market Operator, Transmission Licensee or Single Buyer, as it corresponds, which shall:
 - a.1) Contain detailed plans of the proposed change or modification;
 - a.2) State when the generator intends to make the proposed change or modification; and
 - a.3) Set out the proposed tests to confirm that the relevant unit as changed or modified operates in the manner contemplated in the proposal, can comply with this code.
- b) If the System and Market Operator, Transmission Licensee or Single Buyer, as it corresponds, disagrees with the proposal submitted, it may notify the relevant Generator, and the System and Market Operator, Transmission Licensee or Single Buyer, as it corresponds, and the relevant Generator shall promptly meet and discuss the matter in good faith in an endeavour to resolve the disagreement. In case it is not possible to reach such agreement, the matter shall be submitted to MERA for its final decision.
- c) The Operator shall ensure that an agreed change or modification to a BESS or to a subsystem of a BESS is implemented in accordance with the relevant proposal agreed to by the SMO, TL or DL.
- d) The Operator shall notify the SMO, TL or DL promptly after an agreed change or modification to a unit has been implemented.
- e) The Operator shall confirm that a change or modification to the BESS, as described above conforms to the relevant proposal by conducting the relevant tests, in relation to the connection conditions, promptly after the proposal has been implemented.

- f) An Operator shall provide the SMO, TL or DL with a report in relation to any compliance test (including test results of that test, where appropriate), within 20 business days after such test has been conducted.

8.25.2. Implementing modifications

- a) The Generator shall ensure that an approved change or modification to a Unit or to a subsystem of a Unit is implemented in accordance with the relevant proposal approved by the System and Market Operator, Transmission Licensee or Single Buyer, as it corresponds.
- b) The Generator shall notify the System and Market Operator, Transmission Licensee or Single Buyer, as it corresponds, promptly after an approved change or modification to a unit has been implemented.

8.25.3. Testing of modifications

- a) Where there has been a replacement of or a major modification to an existing RPP, the RPP shall be required to demonstrate compliance with these requirements before being allowed to operate commercially.
- b) The Generator shall confirm that a change or modification to any of its Units, as described above, conforms to the relevant proposal by conducting the relevant tests, in relation to these Connection Conditions, promptly after the proposal has been implemented.
- c) Within 20 business days after any such test has been conducted, the relevant Generator shall provide the System and Market Operator, Transmission Licensee or Single Buyer, as it corresponds, with a report in relation to the tests actually performed, including the results of such tests.
- d) The System and Market Operator, the Single Buyer and/or the Transmission Licensee are entitled to be present when such tests are carried out.
- e) Test results shall be attached to the Connection Agreement.

8.26. PROVISION OF DATA AND ELECTRICAL DYNAMIC SIMULATION MODELS

8.26.1. The SMO, DL and TL require suitable and accurate dynamic models in the template specified by the requesting party applying for a connection to the DS or TS, in order to assess reliably the impact of the proposed installation on the dynamic performance and security and stability of the power system.

8.26.2. The required dynamic models must operate under RMS simulation to replicate the performance of the facility or individual units for analysis of the following network aspects:

- a) impact on thermal rating of connected DS or TS equipment
- b) impact on network voltage stability
- c) impact on system frequency stability
- d) impact on QOS at POC
- e) impact on network protection co-ordination
- f) FRT (Fault Ride Through) capability for different types of faults and positions
- g) response to various system phenomena such as:
 - g.1) switching on the network
 - g.2) power swings
 - g.3) small signal instabilities

8.26.3. The dynamic modelling data shall be provided in a format as may be agreed between the RPP generator and the Distributor, TTL or SMO, as applicable.

8.27. DATA EXCHANGE.

8.27.1. **First stage** (during the application for connection), the *generator* shall submit to the SB/TL the following information:

- a) Physical location (including the GPS coordinates)
- b) Site Plan
- c) Number of *units* to be connected.
- d) MW output per unit
- e) Initial phase MW value
- f) Final phase MW value and timelines
- g) Any other information that the service provider may reasonably require.

8.27.2. For the detailed *RPP* design, the *TL* shall make all necessary data available to the *generator* at specified times provided in the Transmission Connection Agreement required at the point of connection.

8.27.3. **Second stage** (after detailed *RPP* designs have been completed but before commissioning the *RPP*) the *RPP generator* shall provide information on

- a) Selected *RPP* technology data.
- b) Fault ride through capability and harmonic studies test report
- c) Generic test model and dynamic modelling data per or *unit* as from the type approval and tests result

8.27.4. **Third stage** (after commissioning and optimisation of the *RPP*) the *generator* is compelled to provide information on:

- a) A validated *RPP* electrical dynamic simulation model using commissioning test data and measurements
- b) Test measurement data in the format agreed between the *RPP generator* and *TL*, as applicable.

8.27.5. In addition, the Generator shall provide the SMO with operational data as prescribed in Appendix **2**.

8.28. APPENDIX 1 - WIND

8.28.1. High Wind Curtailment

- a) It shall be possible to continuously downward regulate the active power supplied by the *RPP* to an arbitrary value in the interval from 100% to at least 40% of the rated power. When downward regulation is performed, the shutting-down of individual wind turbine *generator* systems is allowed so that the load characteristic is followed as well as possible.
- b) The wind power plant shall stay connected to the *TS and DS* at average wind speeds below a predefined cut-out wind speed. To prevent instability in the *TS and DS*, the wind power plant shall be equipped with an automatic downward regulation function making it possible to avoid a temporary interruption of the active power production at wind speeds close to the cut-out wind speed.
- c) Downward regulation shall be performed as continuous or discrete regulation. Discrete regulation shall have a step size of maximum 25% of the rated power within the hatched area shown in Figure 15. When downward regulation is being performed, the shutting-down of individual wind turbine *generator* systems is allowed. The downward regulation band shall be agreed with the *SMO* upon commissioning of the wind power plant.

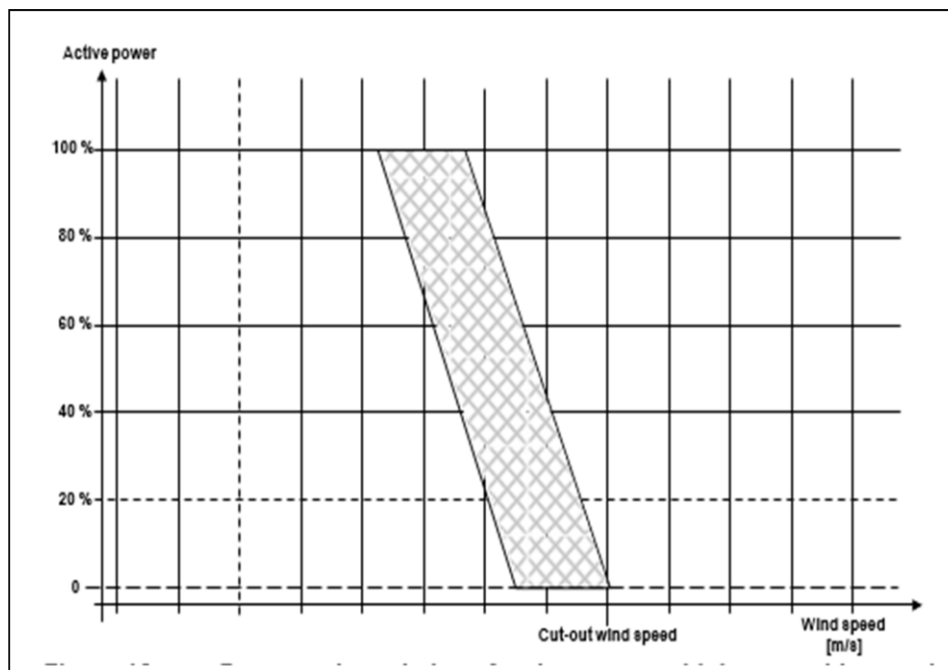


Figure 8.28-1: Downward regulation of active power at high renewable speed.

APPENDIX 2: Documentation

8.28.2. APPENDIX 2: MASTER DATA

Description	Text
Identification:	
Name of <i>electricity supply undertaking</i>	
Plant name	
ID number	
Planned commissioning	
Technical data:	
Manufacturer	
Type designation (model)	
Type approval	
Approval authority	
Installed kW (<i>rated power</i>)	
Cos ϕ (<i>rated power</i>)	
Cos ϕ (<i>20% rated power</i>)	
Cos ϕ (<i>no load</i>)	
3-phase short-circuit current immediately in front of the <i>power plant</i> (RMS)	
<i>Point of connection</i>	
Voltage level	

Description	
Plant address:	
Contact person (technical)	
Address1	
X/Y coordinates	
Title number	
Owners' association on titled land	
Owner:	
C ID number	
Company name	
Contact person (administrative)	
Address1	
To the right/left	
Email address	

8.28.3. Step-Up Transformer

Description	Value
Make	
Type	
Comments	

Description	Symbol	Unit	Value
Nominal apparent power (1 p.u.)	S_n	MVA	
Nominal primary voltage (1 p.u.)	U_p	kV	
Nominal secondary voltage	U_s	kV	
Coupling designation, eg Dyn11	-	-	
Step switch location	-	-	Primary side Secondary side
Step switch, additional voltage per step	d_{utp}	%/trin	
Step switch, phase angle of additional voltage per step:	ϕ_{itp}	degree/step	
Step switch, lowest position	n_{tpmin}	-	
Step switch, highest position	n_{tpmax}	-	
Step switch, neutral position	n_{tp0}	-	
Short-circuit voltage, synchronous	u_k	%	
Copper loss	P_{cu}	kW	
Short-circuit voltage, zero system	u_{k0}	%	
Resistive short-circuit voltage, zero-sequence system	u_{kr0}	%	
No-load current	I_0	%	
No-load loss	P_0	%	
Internal resistance of discharge	R_{dis}	Ω	
Charging Capacity	Q_{bat}	kWh	
Maximum Charging Capacity	$Q_{bat} (max)$	kWh	
Minimum Charging Capacity	$Q_{bat} (min)$	kWh	
Efficiency of charge.	η_{ch}	%	
Efficiency of discharge	η_{dis}	%	

8.28.4. Single Line Diagram (SLD) Representation

This applies to all RPPs of category B and C and for BESS it includes A3. The SMO or local TL may request that a single-line diagram representation be provided for category A.

-
- a) An *SLD* representation of the plant shall be created, with indication of *POC*, metering points, including settlement metering, limits of ownership and operational supervisor limits/limits of liability. In addition, the type of designation for the switchgear used shall be stated so as to make it possible to identify the correct connection terminals.
 - b) In instances when a *SLD* representation is included in the grid use agreement between *RPP Generator* and *SMO*, the *grid connection agreement* can be enclosed as documentation.

8.28.5.PQ Diagram

This applies to all of category B and C and includes A3 for BESS. The *SMO* or local *network operator* may also request that a PQ diagram representation be provided for *RPPs* of category A.

8.28.6.Short-circuit data

Application: This applies to all *RPPs* of category B and C.

For the purposes of static calculations, the *RPP generator* shall provide short-circuit data at *RPP* unit nominal output.

8.29. APPENDIX 3: COMPLIANCE TEST SPECIFICATIONS

This section specifies the procedures for testing to verify compliance with this Code.

8.29.1. Protection Function Verification

Parameter	Reference	Description
Protection function and settings	Section 8.16	APPLICABILITY AND FREQUENCY All new <i>BESS</i> coming online or at which major refurbishment or upgrades of protection systems have taken place
		Routine review: Confirm compliance every 6 years.
		PURPOSE To ensure that the relevant protection functions in the <i>BESS</i> are coordinated and aligned with the system requirements.
		PROCEDURE <ol style="list-style-type: none"> 1) Establish the system protection function and associated trip level requirements from the <i>SMO</i> or <i>TL and DL</i>. 2) Derive protection functions and settings that match the <i>BESS</i> and system requirements. 3) Confirm the stability of each protection function for all relevant system conditions. 4) Document the details of the trip levels and stability calculations for each protection function. 5) Convert protection tripping levels for each protection function into a per <i>unit</i> base. 6) Consolidate all settings in a per <i>unit</i> base for all protection functions in one document. 7) Derive actual relay dial setting details and document the relay setting sheet for all protection functions. 8) Document the position of each protection function on one single line diagram of the generating <i>unit</i> and associated connections. 9) Document the tripping functions for each tripping function on one tripping logic diagram. 10) Consolidate detail setting calculations, per unit setting sheets, relay setting sheets, plant base information on which the settings are based, tripping logic diagram, protection function single line diagram and relevant protection relay manufacturers' information into one document. 11) Submit to the <i>SMO</i>, <i>TL and DL</i> for its acceptance and update.
		Review: <ol style="list-style-type: none"> 1) Review Items 1 to 10 above. 2) Submit to the <i>SMO</i>, <i>TL and DL</i> for its acceptance and update. 3) Provide to the <i>SMO</i>, <i>TL and DL</i> with one original master copy and one working copy.
		ACCEPTANCE CRITERIA All protection functions are set to meet the necessary protection requirements of the <i>BESS</i> with a minimal margin, optimal fault clearing times and maximum plant availability
Submit a report to the <i>SMO</i> , <i>TL and DL</i> one month after commissioning and six-yearly for routine tests.		

8.29.2. Protection Integrity Verification

Parameter	Reference	Description
Protection function and settings	Section 8.16	<p>APPLICABILITY AND FREQUENCY</p> <p>All new <i>BESS</i> coming on line or after major works of refurbishment of protection or related plant. Also, when modification or work has been done to the protection, items 2 to 5 must be carried out. This may, however, be limited to the areas worked on or modified</p>
		<p>Routine review: All <i>BESS</i> on: item 1 below: Review and confirm every 6 years Item 2, and 3 below: at least every 12 years</p> <p>PURPOSE</p> <p>To confirm that the protection has been wired and functions according to the specifications.</p>
		<p>PROCEDURE</p> <ol style="list-style-type: none"> 1) Apply final settings as per agreed documentation to all protection functions. 2) With the <i>unit</i> off load and de-energized, inject appropriate signals into every protection function and confirm correct operation and correct calibration. Document all protection function operations. 3) Carry out trip testing of all protection functions, from origin (e.g. Buchholz relay) to all tripping output devices (e.g. HV breaker). Document all trip test responses. 4) Apply short-circuits at all relevant protection zones and with <i>BESS</i> at nominal speed excite <i>the plant</i> slowly, record currents at all relevant protection functions and confirm correct operation of all relevant protection functions. Document all readings and responses. Remove all short-circuits. 5) With the <i>BESS</i> at nominal production. Confirm correct operation and correct calibration of all protection functions. Document all readings and responses.
		<p>Review:</p> <p>Submit to the <i>SMO, TL and DL</i> for its acceptance and update.</p>
		<p>ACCEPTANCE CRITERIA</p> <ol style="list-style-type: none"> 1) All protection functions are fully operational and operate to required levels within the relay <i>OEM</i> allowable tolerances. 2) Measuring instrumentation used shall be sufficiently accurate and calibrated to a traceable standard. 3) Submit a report to the <i>SMO, TL and DL</i> one month after test.

8.29.3.Fault Ride through Simulations

Parameter	Reference	Description
Simulations of fault ride through voltage droops and peaks	Section 8.6 depending on category	<p>APPLICABILITY</p> <p>All new facilities coming on line and after major modifications or refurbishment of related plant components or functionality.</p>
		<p>Routine test/reviews: None.</p>
		<p>PURPOSE</p> <p>To confirm that the limits for all power quality parameters specified is met</p>
		<p>PROCEDURE</p> <p>By applying the electrical simulation model for the entire plant it shall be demonstrated that the facility performs to the specifications.</p> <ul style="list-style-type: none"> a) Area A - the facility shall stay connected to the network and uphold normal production. b) Area B - the facility shall stay connected to the network. The RPP shall provide maximum voltage support by supplying a controlled amount of reactive power within the design framework offered by the technology, see Figure 8.6.3. c) Area C - the facility is allowed to disconnect. d) Area D - the facility shall stay connected. The RPP shall provide maximum voltage support by absorbing a controlled amount of reactive power within the design framework offered by the technology, see Figure 8.6.3
		<p>ACCEPTANCE CRITERIA</p> <ul style="list-style-type: none"> 1) The dynamic simulations shall demonstrate that the facility fulfils the requirements specified. 2) Submit a report to the <i>SMO, TL or another network operator</i> three month after the commission

8.29.4. Active Power Control Capability Verification

Parameter	Reference	Description
Active power control function and operational range	Sections 8.17 and 8.18 depending on category	<p>APPLICABILITY All new facilities coming on line and after major modifications or refurbishment of related plant components or functionality.</p>
		<p>Routine test/reviews: Confirm compliance every 6 years.</p> <p>PURPOSE To confirm that the active power control capability specified is met.</p>
		<p>PROCEDURE The following tests shall be performed within a minimum active power level range of at least 0.2 p.u. or higher</p> <ol style="list-style-type: none"> 1) The <i>facility</i> will be required to regulate the active power to a set of specific setpoints within the design margins. 2) The facility will be required to obtain a set of active power setpoints within the design margins with minimum two different gradients for ramping up and two different gradients for ramping down. 3) The <i>facility</i> will be required to maintain as a minimum two different set levels of spinning reserve within the design margins. 4) The <i>facility</i> will be required to operate as a minimum to limit active power output according to two different absolute power constraint set levels within the design margins. 5) The facility <i>will</i> be required to verify operation according to as a minimum two different parameter sets for a frequency response curve within the design margins
		<p>ACCEPTANCE CRITERIA</p> <ol style="list-style-type: none"> 1) The <i>BESS</i> shall maintain the set output level within $\pm 2\%$ of the capability registered with the <i>SMO, TL and DL operator</i> for at least one hour. 2) The <i>BESS</i> shall demonstrate ramp rates with precision within $\pm 2\%$ of the capability registered with the <i>SMO, TL and DL</i> for ramp up and down. 3) The <i>BESS</i> shall maintain a spinning reserve set level within $\pm 2\%$ of the capability registered with the <i>SMO, TL and DL</i> for at least one hour. 4) The <i>BESS</i> shall maintain an absolute power constraint set level within $\pm 2\%$ of the capability registered with the <i>SMO</i> for at least one hour. 5) The <i>BESS</i> shall demonstrate that the requested frequency response curves can be obtained. 6) Submit a report to the <i>SMO, TL and DL</i> one month after the test.

8.29.5. Reactive Power Control Capability Verification

Parameter	Reference	Description
Reactive power control function and operational range	Sections 8.11 and 8.12 depending on category	<p>APPLICABILITY All new <i>facilities</i> coming on line and after major modifications or refurbishment of related plant components or functionality.</p>
		<p>Routine test/reviews: Confirm compliance every 6 years.</p> <p>PURPOSE To confirm that the reactive power control capability specified is met.</p>
		<p>PROCEDURE The following tests shall be performed within a minimum active power level range of at least 0.2 p.u. or higher</p> <ol style="list-style-type: none"> 1) The <i>facility</i> will be required to regulate the voltage at the PCC to a set level within the design margins. 2) The facility will be required to provide a fixed Q to a set level within the design margins. 3) The facility will be required to obtain a fixed PF within the design margins
		<p>ACCEPTANCE CRITERIA</p> <ol style="list-style-type: none"> 7) The <i>facility</i> shall maintain the set voltage within $\pm 5\%$ of the capability registered with the <i>SMO, TL or another network operator</i> for at least one hour. 8) The <i>facility</i> shall maintain the set Q within $\pm 2\%$ of the capability registered with the <i>SMO, TL or another network operator</i> for at least one hour. 9) The <i>facility</i> shall maintain the set PF within $\pm 2\%$ of the capability registered with the <i>SMO, TL or another network operator</i> for at least one hour. 10) Submit a report to the <i>SMO, TL or another network operator</i> one month after the test.

8.29.6. Power Quality Calculations

Parameter	Reference	Description
Power quality calculations for: 1) Rapid voltage changes 2) Flicker 3) Harmonics 4) Inter-harmonics 5) High frequency disturbances	Section 8.15.2 depending on category	APPLICABILITY All new facility coming on line and after major modifications or refurbishment of related plant components or functionality.
		Routine test/reviews: Confirm compliance every 6 years.
		PURPOSE To confirm that the limits for all power quality parameters specified is met.
		PROCEDURE The following tests shall be calculated within a minimum active power level range from 0.2p.u. to 1.0p.u. 1) Calculate the levels for rapid voltage changes are within the limits specified over the full operational range. 2) Calculate the flicker levels are within the limits specified over the full operational range. 3) Calculate the harmonics are within the limits specified over the full operational range. 4) Calculate the interharmonics are within the limits specified over the full operational range. 5) Calculate the disturbances higher than 2 Hz are within the limits specified over the full operational range.
		ACCEPTANCE CRITERIA 1) The calculations shall demonstrate that the levels for rapid voltage changes are within the limits specified over the full operational range. 2) The calculations shall demonstrate that the flicker levels are within the limits specified over the full operational range. 3) The calculations shall demonstrate that the harmonics are within the limits specified over the full operational range. 4) The calculations shall demonstrate that the interharmonics are within the limits specified over the full operational range. 5) The calculations shall demonstrate that the disturbances higher than 2 Hz are within the limits specified over the full operational range 6) Submit a report to the <i>System Operator</i> one month after the test.

a) **Power quality calculations**

Parameter	Reference	Description
Power quality calculations for: <ul style="list-style-type: none"> • Rapid Voltage changes • Flicker • Harmonics • Inter-harmonics • High frequency disturbances 	Section 8.16 depending on category	<p>APPLICABILITY All new <i>RPPs</i> coming on line and after major modifications or refurbishment of related plant components or functionality.</p> <p>Routine test/reviews: Confirm compliance every 6 years.</p> <p>PURPOSE To confirm that the limits for all power quality parameters specified is met.</p> <p>PROCEDURE The following tests shall be calculated within a minimum active power level range from 0.2p.u. to 1.0p.u.</p> <ul style="list-style-type: none"> a.1) Calculate the levels for rapid voltage changes are within the limits specified over the full operational range. a.2) Calculate the flicker levels are within the limits specified over the full operational range. a.3) Calculate the harmonics are within the limits specified over the full operational range. a.4) Calculate the interharmonics are within the limits specified over the full operational range. a.5) Calculate the disturbances higher than 2 Hz are within the limits specified over the full operational range. <p>ACCEPTANCE CRITERIA</p> <ul style="list-style-type: none"> (i) The calculations shall demonstrate that the levels for rapid voltage changes are within the limits specified over the full operational range. (ii) The calculations shall demonstrate that the flicker levels are within the limits specified over the full operational range. (iii) The calculations shall demonstrate that the harmonics are within the limits specified over the full operational range. <ul style="list-style-type: none"> 1. The calculations shall demonstrate that the interharmonics are within the limits specified over the full operational range. 2. The calculations shall demonstrate that the disturbances higher than 2 Hz are within the limits specified over the full operational range

SECTION 9: TECHNICAL REQUIREMENTS FOR THE DISTRIBUTION LICENSEE AND BULK SUPPLY CUSTOMERS AT THE POINT OF CONNECTION

9.1. PURPOSE AND SCOPE

- 9.1.1. This section describes connection conditions for the Distribution Licensee(s) and Bulk Supply Customers.
- 9.1.2. The Transmission Licensee shall offer to connect and, subsequent to the signing of the relevant agreements, make available a Point of connection to the Distribution Licensee(s) or Bulk Supply Customers.
- 9.1.3. A User may request additional reinforcements to the TS over and above that which could be economically justified as described in the section on TS Planning and Development. The Transmission Licensee shall provide such reinforcements if the User agrees to bear the costs, which shall be priced according to the Tariff Methodology provisions.
- 9.1.4. This Part applies to the following entities:
- a) The Transmission Licensee;
 - b) The System and Market Operator;
 - c) The Distribution Licensee(s); and
 - d) Bulk Supply Customers.

9.2. POWER FACTOR AT THE POINT OF CONNECTION

- 9.2.1. Distribution Licensees and Bulk Supply Customers shall take all reasonable steps to ensure that the power factors at the Connection Point is at all times 0.85 lagging or better, unless otherwise agreed with the Transmission Licensee and reflected in the Connection Agreement. This requirement applies to each Point of connection individually for Users with more than one Connection Point. A leading power factor shall not be acceptable, unless specifically agreed to and reflected in the Connection Agreement.
- 9.2.2. Should the power factor be less than the said limit during any 10 (ten) demand- integrated half hours in a single calendar Month;
- a) In the case of a Distribution Licensee: The Distribution Licensee and the Transmission Licensee shall jointly determine the plans of action to rectify the situation. Overall lowest cost solutions shall be sought.
 - b) In the case of a Bulk Supply Customer: The Transmission Licensee shall request to the Bulk Supply Customer to rectify the situation, indicating the maximum timeframe for this rectification to be materialized.

9.3. PROTECTION

- 9.3.1. Each Participant shall take all reasonable steps to protect its own plant.
- 9.3.2. The Protection requirements with which the Users shall interface are described in section 5. The detailed Protection applications, in so far as the equipment of one Participant may have an impact on the other, shall be agreed to in writing by the relevant Participants.
- 9.3.3. The Transmission Licensee to co-ordinate Protection of licensees to ensure proper grading. .

9.4. FAULT LEVELS

- 9.4.1. Minimum fault levels at each Point of connection shall be maintained by the Transmission Licensee, under normal operating conditions, to ensure compliance with the relevant QOS standards and to ensure correct operation of the Protection systems.
- 9.4.2. The Transmission Licensee shall liaise with Users, on how fault levels are planned to change and on the best overall solutions when equipment ratings become inadequate. Overall lowest cost solutions shall be sought and a joint impact assessment shall be done covering all aspects. The Transmission Licensee shall communicate the potential impact on safety of people when equipment ratings are exceeded.
- 9.4.3. The System and Market Operator shall bi-annually, or when substantial deviations have taken place, publish updated minimum and maximum normal operating fault levels for each Point of connection. The User shall ensure his equipment is capable of operating at the specified fault level ranges.
- 9.4.4. If equipment fault level ratings are or will be exceeded, the Distributor or the Bulk Supply Customer, as it corresponds, shall promptly notify the Transmission Licensee. The Transmission Licensee shall seek overall lowest cost solutions to address fault level problems. Corrective action shall be at the cost of the relevant asset owner.

9.5. DISTRIBUTION LICENSEE OR BULK SUPPLY CUSTOMER NETWORK PERFORMANCE

- 9.5.1. If the Distribution Licensee or Bulk Supply Customer network performance falls below acceptable levels and affects the quality of supply to other Users or causes damage (direct or indirect) to the Transmission Licensee equipment, the process for dispute resolution, as described in PART 1: Section 4: of the Dispute, Mediation, Resolution and Appeal Mechanism of the Grid Code Technical Committee, shall be followed.
- 9.5.2. Acceptable network performance shall be:
- a) Performance that complies with the Transmission Licensee operating and maintenance procedures at that Substation, and
 - b) Performance that complies with the minimum agreed IEC standards 61000 of QOS.
- 9.5.3. In case the Distribution Licensee(s) or Bulk Supply Customers are aware that their network performance could be unacceptable as described above, they shall take reasonable steps at their own cost to overcome the shortcomings, for example by improving line maintenance practices, improving Protection and breaker operating times, replacing the said equipment, installing additional network breakers, changing operating procedures, installing fault-limiting devices, etc., where necessary. These changes should be effected in consultation with the Transmission Licensee on both the technical scope and the time frame.

9.6. THE TRANSMISSION LICENSEE'S DELIVERED QUALITY OF SUPPLY

- 9.6.1. Quality of supply is a shared responsibility between the Transmission Licensee and its Users and will be based on Malawian QOS standards stated in the By-Laws and where applicable IEC 61000 as agreed with all Stakeholders.
- 9.6.2. The Transmission Licensee shall agree with its Users, for every Point of connection, at least on the following QOS parameters, taking local circumstances, historical performance and the relevant standards into account:
- a) Interruption performance
 - b) Voltage regulation performance
 - c) Dip performance
 - d) Total harmonic distortion performance
 - e) Flicker performance

-
- f) Unbalance performance
 - g) Voltage Swells
- 9.6.3. Customer responsibilities in terms of harmonic current injection, unbalanced currents and addition of voltage dips to the network may also be included in the Connection.
- 9.6.4. A time period for monitoring performance shall be allowed before performance is agreed to for the first time in terms of interruptions and dips. This time period shall not more than three years. For harmonic voltages and voltage unbalance, performance can be monitored after one week of measurements.
- 9.6.5. Where the Transmission Licensee fails to meet the agreed QOS parameters and also requirements stated in sub section 3.2.2 subsection 3, it shall take reasonable steps at own cost to overcome the shortcomings, for example by improving line maintenance practices, improving Protection and breaker operating times, if necessary by replacing the said equipment, installing additional network breakers, changing operating procedures, by installing fault-limiting devices if the number of faults cannot be reduced, etc. These changes should be effected in consultation with;
- a) The involved User; and
 - b) the Single Buyer in cases which the nature or associated cost of the proposed modification requires significant investments on both the technical scope, time frame and associated costs.

9.7. EQUIPMENT REQUIREMENTS

- 9.7.1. Where the Distribution Licensee or Bulk Supply Customer need to install equipment that connects directly with Transmission Licensee equipment in Transmission substations, such equipment shall adhere to the Transmission Licensee design and standards.
- 9.7.2. The Transmission Licensee may require Users to provide documentary proof that their equipment complies with all relevant standards, both by design and by testing.
- 9.7.3. The Distribution Licensee or Bulk Supply Customer wishing to install a new series capacitor or modify the size of an existing series capacitor, shall at his expense and according to the Transmission Licensee's requirements, arrange for sub synchronous resonance, harmonic and Protection coordination studies to be conducted to ensure that sub synchronous resonance will not be excited in any generator.

SECTION 10: TRANSMISSION LICENSEE TECHNICAL DESIGN REQUIREMENTS

10.1. OBJECTIVE

10.1.1. The purpose of this section is to document the design and other technical standards that the *Transmission Licensee* shall adhere to.

10.2. EQUIPMENT DESIGN STANDARDS

10.2.1. Primary Substation Equipment shall comply with Malawi or IEC specifications. Application shall cater for local conditions, e.g. increased pollution levels and should be determined by or in consultation with the User.

10.2.2. The Transmission Licensee shall design, install and maintain equipment in accordance with the approved standards.

10.2.3. Participants may require the Transmission Licensee to provide documentary proof that their equipment complies with all relevant standards, both by design and by testing.

10.3. CLEARANCES

10.3.1. Clearances shall at least comply with the Electricity By – Law requirements.

10.4. CT AND VT RATIOS AND CORES

10.4.1. CT and VT ratios and cores for connection shall be determined by Transmission Licensee in consultation with the Participant in accordance with the Malawi Standard.

10.5. TRANSMISSION SUBSTATION STANDARD BUSBAR ARRANGEMENTS

10.5.1. The reliability and availability of the TS is not dependent only on TS lines, transformers, and other primary and secondary plant; the busbar layout also plays a part. It is important that the busbar layout and what it can do for the reliability and availability of the User's supply be prudently assessed when planning the TS.

10.5.2. The standard arrangement shall be based on providing one busbar zone for every main transformer/line connected to the busbar. The Transmission Licensee shall, however, consider local conditions, type of equipment used, type of load supplied and other factors in the assessment of the required busbar redundancy.

10.6. USE OF BYPASSES

10.6.1. Bypasses provide high line availability by allowing circuit breakers to be taken out of service for maintenance and testing without affecting line availability.

10.6.2. The bypass with single busbar selection shall be used at 132 kV and above on a single line radial feeder to provide continuity of supply when maintaining the line breakers

10.6.3. The bypass with double busbar selection shall be used on 132 kV and above.

10.7. MOTORISED ISOLATORS

10.7.1. The provision of motorised isolators at new substations is to be based on the following:

- a) All new isolators shall be motorised at new substations.
- b) Isolators of 132 kV at new substations and below shall be specified on individual merit (importance ranking vs. cost vs. remoteness)

10.8. EARTHING SWITCH

10.8.1. Earthing Switch shall be provided at new substations where the fault level is designed for 20 kA and above.

10.9. BUSBAR PROTECTION CT'S

10.9.1. For 3 phase busbar Protection schemes, single sets of CT's shall be used on bus couplers and bus section breakers (i.e. 3 CT's instead of 6 CT's) to reduce the probability of a double bus zone outage for a CT fault on a bus coupler or bus section breaker (i.e. non-overlapped zones will apply).

10.9.2. At Power Station, overlapped bus zones shall be retained to ensure fastest possible clearance of busbar faults.

10.10. TELE-CONTROL

10.10.1. Either Participant may be permitted to have tele-control equipment in the substations/ Switchyards / buildings of the other Party, to perform agreed monitoring and control. This permission shall be reflected in the Connection Agreement. Access shall be provided to such equipment.

10.10.2. The Distribution Licensee(s) shall have reliable SCADA facilities (including telecommunications, computers and RTUs) for the distribution system connected directly to the TS, to provide the necessary response where system conditions require.

10.11. TRANSFORMER TAP CHANGER

10.11.1. The Transmission Licensee shall install on load tap changing facilities on all new transformers.

10.11.2. Transformers used in the TS at 220kV and above are normally not on automatic tap change. Transformers supplying a customer are usually on automatic tap change. Voltage levels, sensitivity and time settings and on/off auto tap changing shall be determined by the System and Market Operator in consultation with the customer, and the Transmission Licensee.

10.12. SUBSTATION DRAWINGS

10.12.1. The following set of drawings shall be made available by the respective asset owners for all points of supply, if required by the other Party for the purposes of connection:

- a) Station single Diagram
- b) Key Plan
- c) Bay Layout Schedules
- d) Foundation, Earth mat ,Trench Layout including quarry stone specifications (depth and size)
- e) Steelwork Marking Plan
- f) Security Fence Layout
- g) Terrace, Access Road and Drainage Layout
- h) Transformer Plinth
- i) General Arrangement
- j) Sections
- k) Slack Span Schedule
- l) Barrier Fence Layout
- m) Security Lighting

-
- n) Floodlighting Parameter Sketch
 - o) Protection details
 - p) Contour Plan

SECTION 11: TS PROTECTION REQUIREMENTS

11.1. GENERAL CONSIDERATIONS

- 11.1.1. This section specifies the minimum Protection requirements for the Transmission System as well as typical settings, to ensure adequate performance of the TS.
- 11.1.2. The Transmission Licensee shall at all times install and maintain Protection installations that comply with the provisions of this section.
- 11.1.3. The Transmission Licensee shall conduct periodic testing of equipment and systems to ensure and demonstrate that these are performing to the design specifications. Tests procedures shall be according to the manufacturers' specifications.
- 11.1.4. The Transmission Licensee shall make available to Users all results of test performed on equipment for reasonable requests.
- 11.1.5. Protection schemes are generally divided into:
- a) Equipment Protection and
 - b) System Protection.

11.2. EQUIPMENT PROTECTION REQUIREMENTS

11.2.1. Feeder Protection: 220kV and above

- a) Protection Design Standards
 - a.1) New feeders shall be protected by two equivalent Protection systems – Main 1 and Main 2.
 - a.2) The Main 1 and Main 2 Protection systems shall be fully segregated in secondary circuits.
 - a.3) An additional earth fault function shall be incorporated in the protection scheme as back up in the event of failure of main protection to detect high resistance faults.
- b) Protection Settings
 - b.1) The Protection relays shall provide reliable Protection against all possible faults, provide remote and/or local back up for uncleared busbar faults and shall not be set to provide overload tripping.
 - b.2) Where specifically required, the feeder Protection may be set, if possible, to provide remote back up for other faults as agreed upon with other Participants.
- c) Automatic Re-closing
 - c.1) A selectable Automatic re-closing (ARC) facility shall be provided on all feeders.
 - c.2) The System and Market Operator, in consultation with the Transmission Licensee, shall decide on ARC selection based on real time system, environmental constraints and consultation with Users, with regard to equipment capabilities and in accordance with the ARC philosophy below. All ARC settings and methodology shall be implemented by the Transmission Licensee and be made available to Users on request.
- d) ARC cycles
 - d.1) For single pole circuit breaker, either of the following two ARC cycles for single phase faults shall be used:
 - Double attempt ARC cycle for persistent fault: 1ph fault – 1ph trip – 1ph ARC – 3ph trip – 3ph ARC – 3ph trip – lockout
 - Single attempt ARC cycle for persistent fault: 1ph fault – 1ph trip – 1ph ARC – 3ph trip – lockout
 - d.2) For a triple pole circuit breaker during single phase faults : 1ph fault - 3ph trip – 3ph ARC – 3ph trip – Lockout.

d.3) The ARC cycle for a multiphase (mph) fault shall be: mph fault – 3ph trip – 3ph ARC– 3ph trip – lockout

d.4) On some lines the ARC may be switched off according to the following operational needs:

- Sporadically, when high risk of line fault is recognised, for live line work or to reduce breaker duty cycle where breaker’s condition is questionable.
- Periodically, during season of high fault frequency,
- Permanently, on lines with the highest fault frequency throughout the year or on Users’ request.
- Whenever an ARC could initiate a severe power swing or an Out-Of-Step condition in weakly interconnected systems.

e) Single Phase ARC

In most applications the dead time of Single Phase ARC shall be selected to 1 second but may differ for different system requirements. (The closing of the breaker is performed without synchronisation as the synchronism is maintained via remaining phases that are closed during the whole incident

f) Three Phase ARC

f.1) Fast ARC

Fast ARC i.e. fast closing of the breaker without checking synchronism is not used on the TS to avoid stress to the rotating machines at the Power Stations and at the Users’ plant. This option is available on Protection panels and can be selected in case of emergency (i.e. when as a result of outages or disturbance load/generation islands are interconnected via a single line). The operating practice, however, is to use only single phase ARC (fast by its nature) in such situations as a compromise between supply reliability and stress to the equipment.

f.2) Slow ARC

The Dead Line Charging (DLC) end is selected in line with the Table 6 below based on fault level (FL) at the connected substations A and B.

Table 6: Selection of Dead Line charging end of the line.

End A End B	Substation FL<10kA	Substation FL>10kA	Power Station
Substation FL<10kA	Substation with higher FL	Substation A	Substation B
Substation FL>10kA	Substation B	Substation with lower FL	Substation B
Power Station	Substation A	Substation A	Power Station with lower FL

In most applications the dead time of slow ARC shall be selected to 3 seconds at DLC end of the line. At the synchronising end of the line the ARC dead time shall be selected to 4 seconds.

The close command shall be issued only after synch-check is completed. This may take up to 2 seconds if synchronising relays are not equipped with direct slip frequency measurement. The breaker may take longer to close if its mechanism is not ready to close after initial operation at the time when the close command is issued.

On the line between two Power Stations the dead time at the DLC end should be extended to 25 seconds to allow generator rotor oscillations to stabilise. The dead time at the synchronising end should then be extended accordingly to 30 seconds.

The synchronising relays shall be installed at both ends of the line to enable flexibility in ARC cycles and during restoration.

f.3) Power Swing Blocking

New distance relays on the TS shall be equipped with power swing blocking facility. All unwanted operations of distance relays during power swing conditions shall be blocked on the TS

11.2.2. Feeder Protection: 132kV and below, at Transmission Licensee substations

a) Design Standard

a.1) These feeders shall be protected by a single Protection system, incorporating either distance or differential Protection relays, unless otherwise agreed. Back up shall be provided by definite time or inverse definite minimum time (IDMT) over-current and earth fault relays.

a.2) The Protection shall be equipped with automatic re-closing. Synchronising relays shall be provided on feeders that operate in "ring circuits" and are equipped with line voltage transformers.

b) Protection Settings

Protection relays shall provide reliable Protection against all possible short circuits, provide remote and/or local back up for Un-cleared busbar faults and should not be set to provide overload tripping where measurements and alarms are provided on SCADA system. In isolated applications where SCADA system is not available, overload tripping shall be provided. The control centre shall take responsibility to reduce load to an acceptable level as quickly as possible where overload condition are reported.

c) Automatic Re-closing

Transmission Licensee shall consult with the involved Participant(s) to determine ARC requirements. The System and Market Operator may specify additional ARC requirements for system Security reasons, which could extend beyond the Transmission Licensee substations.

11.2.3. Tele-Protection Requirements

11.2.4. New distance Protection systems shall be equipped with tele-Protection facilities to enhance the speed of operation in meshed system.

11.2.5. Transformer and Reactor Protection

a) The standard schemes for transformer Protection shall cover the following fault conditions:

a.1) Faults within the tank;

a.2) Faults on transformer connections;

a.3) Overheating; and

a.4) Faults external to the transformer.

b) The Transmission Licensee shall consider the application of the following relays in the design of the Protection system:

b.1) Transformer IDMT E/F

The Secondary Side (MV) E/F Protection is to discriminate with the feeder back-up E/F Protection for feeder faults

b.2) Transformer HV/MV IDMT O/C

The Load Dispatch Centre shall require that the IDMT O/C does not operate for twice transformer full load. Overloading of the transformer is catered for by the winding temperature Protection. However, network requirements may be such that the above standard cannot be applied. In this case, a mutually agreed philosophy may be used.

b.3) Transformer HV/MV Instantaneous O/C

This is a back-up Protection shall cater for flash-overs external to the Transformer (TRFR) on the Primary (HV) side or Secondary (MV) side and should operate for

minimum fault conditions (possibly as well for an E/F condition). However, careful consideration shall be given to settings so that tripping for through faults or for magnetising inrush current is avoided.

b.4) Transformer LV (Tertiary) IDMT/Instantaneous O/C

This Protection shall operate for external faults between the main delta winding of the TRFR and the auxiliary TRFR, but not for faults on the secondary side of the auxiliary TRFR. The auxiliary TRFR is protected by Buchholz and temperature Protection.

b.5) Transformer Current Differential Protection

This is the main transformer Protection for E/F and phase to phase faults. Maximum sensitivity is required, while ensuring no incorrect operation for load, for through fault conditions or for magnetising inrush current, with its attendant decaying offset.

b.6) Transformer High Impedance Restricted E/F

This Protection shall be applied as standard for all transformers with grounded star point.

b.7) Transformer Thermal Overload

Winding temperature and oil temperature relays, supplied by the manufacturer shall be used to prevent transformer damage and minimize its life span due to excessive loading for the ambient temperature or during failure of the cooling system.

11.2.6. Transmission System Busbar Protection

Busbars shall be protected by current differential Protection (bus-zone) set to be as sensitive as possible for the "in-zone faults" and maintain stability for any faults outside the protected zone, even with fully saturated CTs.

11.2.7. Transmission System bus coupler and bus section Protection

Bus-coupler and bus-section panels shall be equipped with O/C and E/F Protection.

11.2.8. Transmission System shunt capacitor Protection

- a) All the new high voltage capacitor banks shall be equipped with sequence switching relays to limit inrush current during capacitor bank energisation. Inrush reactors and damping resistors shall also be employed to limit inrush current.
- b) The following Protection functions shall be provided for all types of Protection schemes:
 - b.1) Unbalanced Protection with alarm and trip stages;
 - b.2) Over-current Protection with instantaneous and definite time elements;
 - b.3) Earth fault Protection with instantaneous and definite time sensitive function;
 - b.4) Overload Protection with IDMT characteristic;
 - b.5) Over-voltage with definite time;
 - b.6) Circuit breaker close inhibit for 300 seconds after de-energisation; and
 - b.7) Ancillary functions as indicated below.

11.2.9. Over-voltage Protection

- a) Primary Protection against high transient over-voltages of magnitudes above 140% (e.g. induced by lightning) shall be provided by means of surge arrestors. To curtail dangerous, fast developing over-voltage conditions that may arise as a result of disturbance, additional over-voltage Protection shall be installed on shunt capacitors and feeders;
- b) Over-voltage Protection on shunt capacitors is set to disconnect capacitor at 110% voltage level with a typical delay of 200 milliseconds to avoid unnecessary operations during switching transients;

- c) Over-voltage Protection on the feeders is set to trip the local breaker at voltage level of 120% with a delay of 1 to 2 seconds.

11.2.10. Ancillary Protection functions

Protection systems are equipped with auxiliary functions and relays that enable adequate co-ordination between Protection devices and with bay equipment. The Transmission Licensee shall consider the following functions for all new Protection system designs:

- a) Breaker Fail / Bus trip

Each individual Protection scheme is equipped with breaker fail / bustrip function to ensure fast fault clearance in case of circuit breaker failure to interrupt fault current.

- b) Breaker Pole Discrepancy

Breaker pole discrepancy Protection will compare, by means of breaker auxiliary contacts, state (closed or opened) of breaker main contacts on each phase. When one contact is in a different position from the others a trip command shall be issued after a time delay.

- c) Breaker Anti-pumping

To prevent repetitive closing of the breaker in case of fault in closing circuits the standard Protection schemes shall provide breaker anti pumping timer. Circuit breakers are often equipped with their own anti pumping devices. In such cases anti pumping function is duplicated.

- d) Pantograph Isolator Discrepancy

The pantograph isolator discrepancy relay operates in the same manner as breaker pole discrepancy and shall be used to issue local and remote alarm.

- e) Master Trip Relay

Transformer and reactor Protection schemes shall be equipped with latching master trip relay that require manual reset before the circuit breaker is enabled to close. The master trip relay is operated by unit protection and other Protection relays that indicates the possibility of an internal failure.

11.3. SYSTEM PROTECTION REQUIREMENTS

11.3.1. Under-frequency load shedding

- a) The actions taken on the power system during an under-frequency condition is defined in Part 4: System Operation Code.
- b) Under-frequency load shedding relays shall be installed in the IPS as determined by the System and Market Operator in consultation with the Distribution Licensee(s) and Bulk Supply Customers. The respective asset owners shall pay for the installation and maintenance of these relays.
- c) Under-frequency relays shall be tested periodically. Distribution Licensees and Bulk Supply Customers shall submit to the System and Market Operator a written report of each such test, within a Month of the test being done, in the format specified in the Information Exchange Code. The testing shall be done by isolating all actual tripping circuits, injecting a frequency to simulate a frequency collapse and checking all related functionality.

11.3.2. Out of step tripping (OST)

- a) The purpose for the out-of-step tripping Protection shall separate power system in a situation where a loss of synchronous operation takes place between a unit or units and the main power system. In such a situation system separation is desirable to remedy the situation. Once the islanded system is stabilised it can be reconnected to the main system.
- b) The System and Market Operator shall determine and specify the OST functionality to be installed at selected locations by the Transmission Licensee.

11.3.3. Under-voltage load shedding

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- a) Under-voltage load shedding Protection schemes shall be used to prevent loss of steady-state stability under conditions of large local shortages of reactive power (voltage collapse). Automatic load shedding tripping of suitable loads shall be carried out to arrest the slide.
 - b) The System and Market Operator shall determine and specify the under-voltage load shedding functionality to be installed at selected locations by the Transmission Licensee.

11.3.4. Sub-synchronous resonance Protection

- a) The sub-synchronous resonance (SSR) condition may arise on a power system where a generator is connected to the main power system through long series compensated TS lines. The potential for unstable interaction is sensitive to system topology and is greater with the higher degree of compensation and larger thermal turbo-generators are employed. The SSR condition is addressed either through Protection or mitigation. In case of Protection, a suitable relay shall be deployed as part of the turbo-generator Protection that will lead to the unit disconnection on detection of the SSR condition. The Protection does not reduce or eliminate the torsional vibration, but rather detects it and acts to remove the condition leading to the resonance. Mitigation, on the other hand, acts to reduce or eliminate the resonant condition. Mitigation is needed only under conditions when it is desirable or essential to continue operation when the power system is at or near a resonant condition.
- b) New generators shall liaise with the Single Buyer and the System and Market Operator regarding SSR Protection studies. Least-cost solutions shall be determined by the Single Buyer in accordance with the TS planning and Development Section, and implemented by the relevant asset owner.

11.3.5. Protection against near 50 Hz Resonance

Where there are long and lightly loaded transmission lines, a near 50Hz resonance may arise on the TS network. Adequate reactive compensation therefore needs to be installed on the TS and the influence of *this possibility on the TS and Users* on this near 50Hz resonance needs to be reduced. *Transmission Licensee* has to ensure that the near 50Hz resonance is catered for in any old or new networks.

11.3.6. Protection Settings impact on Network Stability (Dynamic Stability)

Maximum clearance times for Protection in Distribution Licensee or Bulk Supply Customer networks will be determined on a case by case basis in order to ensure Dynamic Stability of the TS.

11.4. PROTECTION SYSTEM PERFORMANCE MONITORING

- 11.4.1. To maintain high level of Protection performance and long term sustainability, the Transmission Licensee shall monitor Protection performance.
- 11.4.2. Each Protection operation shall be investigated for its correctness based on available Information. The Transmission Licensee, with the assistance of the System and Market Operator if deemed necessary, shall provide a report to Users affected by a Protection operation when requested to do so.

11.5. NUMBERING AND NOMENCLATURE OF HV APPARATUS

- 11.5.1. The overall objective of numbering and nomenclature of HV apparatus is to ensure as far as possible, the safe and effective system operation in order to reduce the risk of human error faults.
- 11.5.2. All safety terminology shall comply with the SMO Operating procedures for High Voltage Systems.
- 11.5.3. Participants under guidance from SMO shall agree the numbering of HV apparatus in accordance with the system used from time to time at Point of connection or relevant interface points on its associated switchgear, transformer, etc.

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- 11.5.4. Participants shall provide upon request provide the details of numbering and nomenclature system in order to assist them in planning the numbering and nomenclature for their HV apparatus.
 - 11.5.5. When participants install HV apparatus, shall be responsible for the provision and erection of clear and unambiguous labelling showing the numbering and nomenclature.
 - 11.5.6. Participant shall agree to engineering drawings relating to connecting equipment to the system setup and layout.

11.6. NETWORK MAINTENANCE

- 11.6.1. Participants shall operate and maintain the equipment owned by them. The cost of such operation and maintenance shall be borne by the respective Participants unless such equipment is proved to have been damaged by a negligent act or omission of a Participant other than the owner, its agents or employees, in which case the responsible Participant shall be liable for the costs of repairing such damage.
- 11.6.2. Participants shall monitor the performance of their plant and take appropriate action where deteriorating trends are detected.

PART 3: PLANNING CODE

SECTION 12: INTEGRATED SYSTEM PLANNING

12.1. OBJECTIVE

12.1.1. This section specifies the procedure followed by the Single Buyer to develop the integrated generation and transmission Master Plan

12.2. SYSTEM PLANNING PROCESS

12.2.1. The Single Buyer, with the assistance of the Transmission Licensee and the SMO shall follow an integrated generation and transmission planning process divided into major activities as follows:

- a) Identification of system requirements (in terms of demand to be supplied)
- b) Formulation of options to meet this need (transmission and generation expansion options)
- c) Determination of the investment and operational costs associated with such options.
- d) Evaluation of these options, in order to select the least cost one which ensures compliance with agreed technical limits, and justifiable reliability and quality of supply standards. The evaluation shall be done on the basis of present-day capital costs and future operational costs, using appropriate net discount rates, establishing the net present cost of each option.
- e) Determining the preferred option.
- f) Building a business case for the preferred option using acceptable justification criteria.
- g) Requesting approval of MERA and the Ministry preferred option, initiating execution thereof.

12.3. IDENTIFICATION OF THE NEED FOR SYSTEM DEVELOPMENT

12.3.1. The Single Buyer shall source relevant data from relevant national planning studies, specific User Information, Governmental and User development plans to establish the needs for generation expansion and network strengthening.

The data to be requested from Participants is indicated in Part 6: (Information Exchange Code)

12.4. GLOBAL OBJECTIVE OF INTEGRATED PLANNING

12.4.1. The overall objective of the Integrated Generation and Transmission Planning (Master Plan) is the definition, by the Single Buyer, of a the generation to be installed in Malawi and the associated reinforcements on the transmission system which constitute the least cost option to supply the forecasted demand during the following years.

12.5. FORECASTING THE DEMAND

12.5.1. The Single Buyer is responsible for producing the overall demand forecast for the next five years and updating it annually and for estimating the load forecast for the next 10 years.

12.5.2. The Single Buyer is responsible for producing, in coordination with the System and Market Operator a long-term demand forecast covering at least the next [10] years, to be used in the integrated generation and transmission Master Plan. The long-term demand forecast shall be updated annually, before the end of every year to be used in system planning and to identify need for additional generation or transmission expansion.

12.5.3. The Single Buyer will prepare the load forecast using adequate models, reasonable assumptions and best possible available data, including:

- a) Data provided by the Distribution Licensee(s) and Bulk Supply Customers;
- b) Historical data and trends;

- c) Economic growth projection and new developments or initiatives that may impact significantly load growth; and
- d) Information on international interchanges (imports and approved exports), if any.

12.5.4. Each year and not later than [June 1st], the Single Buyer will submit to MERA and the Ministry, requesting their approval, a 10-year Load Forecast Report, including at least:

- a) The description of the forecasting methodology, models and assumptions
- b) Historical load (consumption, peak demand, growth and trends) and transmission losses during the previous 5 year period;
- c) Deviations between previous long-term load forecasts and actual load and consumption;
- d) At least three scenarios (high, base and low) to take into account forecasting uncertainty;
- e) The explanation of any significant change to the long-term load forecast submitted the previous year, such as revised assumptions and the reasons for such changes.

Once approved, the Single Buyer will publish the long-term load forecast in its website.

12.5.5. The long-term load forecast approved will be used by the Single Buyer for the integrated Generation and Transmission Master Plan.

12.5.6. The long term demand forecast produced will be distributed among all Connection Points. Generation and import capacity plans shall be used to obtain the annual generation patterns.

12.5.7. To forecast the maximum demand (MW) for each TS Substation, the Single Buyer, with the assistance of the Transmission Licensee, shall use Distribution Licensee and Bulk Supply Customer load forecasts. Final loads are reconciled with data from various sources.

12.5.8. The load forecast shall be adjusted at various levels (making use of diversity factors determined from measurements and calculations) to line up with the higher-level data.

12.6. CRITERIA FOR TRANSMISSION / GENERATION EXPANSION

12.6.1. The Single Buyer shall prepare the Generation and Transmission Master Plan for a period not less than the next [10] years, to identify the need for additional capacity (size, fuel and technology) and network expansion. The Generation and Transmission Master Plan shall be update annually, before the end every year.

12.6.2. The Master Plan shall be prepared using adequate models, reasonable assumptions and best available data, and comply with the procedures and criteria established in applicable codes.

12.6.3. In the preparation of the Master Plan, the Single Buyer may contract expert advise and modelling support.

12.6.4. In determining the expected generation capacity and transmission expansion, the Generation and Transmission Master Plan shall include the following resources:

- a) existing generation taking into consideration informed retirement date and expected availability;
- b) generation under construction;
- c) generation projects which are about to be awarded to successful bidders;
- d) generation projects already approved;
- e) generation capacity committed to long-term exports (if any); and
- f) long-term imports agreed with interconnected countries.

12.6.5. The Generation and Transmission Master Plan shall comply with Government energy policies and select the least cost resources to supply the approved load forecast with the required reliability and complying with generation and transmission expansion criteria defined in this Code.

12.6.6. To select the best possible option, in particular regarding technology and fuel, the Single Buyer will include as alternatives:

- a) a list of standard generation projects (type of technology, fuel and size);
- b) a list of candidate lines and new substations of different voltage levels;
- c) potential for additional imports; and
- d) in existing power stations, potential for additional Generating Units or refurbishing.

12.6.7. In designing the generation alternatives, the Single Buyer shall take into consideration any request by the System and Market Operator on special technology or technical characteristics to ensure sufficient ancillary services and load following capability.

12.7. STATUTORY OR STRATEGIC INVESTMENTS

12.7.1. It must also be stressed that Malawi and certain strategic decisions would therefore need to be taken in order to encourage development in the country.

12.7.2. This category of projects includes the following:

- a) Investments formally requested by government. This includes investments that will allow Malawi to become more self-sufficient in electricity supply and issues pertaining to the electrification of Malawi;
- b) Increased connection with neighbouring countries and SAPP requirements to allow the Malawian Electricity Industry access to other markets;
- c) Projects necessary to meet environmental legislation, for example the construction of oil containment dams;

12.7.3. Expenditure to satisfy the requirements of the Labour Act , specifically the Regulations relating to Health and Safety of Employees at Work .This classification is intended to ensure the safety of operating and maintenance personnel who are exposed to possible danger when busy with activities related to electricity transmission;

- a) Possible compulsory contractual commitments; and
- b) Servitude acquisition (Wayleave or Right of way).

12.8. COORDINATION

12.8.1. To ensure adequate generation and reliability and to achieve a least cost integrated planning, the Single Buyer shall perform its planning responsibilities for efficient and economic generation expansion in close coordination with the System and Market Operator and the Transmission Licensee.

12.8.2. The System and Market Operator shall prepare and provide to the Single Buyer an evaluation of medium term [two years] supply, identifying any risk of shortages, transmission congestion or reliability concerns, in particular need for adequate generation capability for peaking capacity and load following. The Single Buyer shall take into consideration these studies and concerns, to adequately address them in the Master Plan.

12.8.3. In preparing the Master Plan, the Single Buyer shall exchange information and coordinate work with the System and Market Operator to protect security of supply by planning adequate generation (in quantity and mix) to supply the total demand with the required reserve margin, reliability standards and the flexibility capacity for load following.

12.8.4. The Single Buyer shall coordinate with the System and Market Operator on the following matters:

- a) The resources mix and required peaking capacity to achieve Generation Adequacy and sufficient load following capability;
- b) The generation expansion criteria and maximum size of new Generating Units, which will affect the reserve margin for the long-term planning; and

c) The requirements for ancillary services.

12.8.5. The Single Buyer shall prepare a request for information for Distribution Companies and Bulk Supply Customers, indicating in details the information that they have to supply for the purpose of the preparation of the Generation Master Plan, and the dates within which this information has to be delivered. The delivery of this information is mandatory.

12.9. INFORMATION REQUIRED

12.9.1. To enable the *Single Buyer* to successfully integrate existing and new Power Stations, detailed Information is required per unit and Power Station, as described in the Information Exchange Code.

SECTION 13: SPECIFIC CRITERIA FOR TRANSMISSION PLANNING

13.1. OBJECTIVE

13.1.1. This section specifies the technical and design criteria and procedures to be applied by the Transmission Licensee in the planning and development of the TS, based on the integrated Master Plan results, and to be taken into account by Users in the planning and development of their own systems. It specifies Information to be supplied by Users to the Transmission Licensee, and Information to be supplied by the Transmission Licensee to Users.

13.1.2. The development of the TS, will arise for a number of reasons including, but not limited to:

- a) development on a User system already connected to the TS;
- b) the introduction of a new TS Substation or Point of connection or the modification of an existing connection between a User and the TS;
- c) The cumulative effect of a number of such developments referred to in (a) and (b) by one or more Users;
- d) the need to reconfigure, decommission or optimise parts of the existing network

13.1.3. Accordingly, the development of the TS may involve work:

- a) at a Substation where User's plant and/or apparatus is connected to the TS;
- b) on TS lines or other facilities which join that Substation to the remainder of the TS;
- c) on TS lines, TS substations or other facilities at or between points remote from that Substation.

13.1.4. The time required for the planning and development of the TS will depend on the type and extent of the necessary reinforcement and/or extension work, the need or otherwise for statutory planning consent, the associated possibility of the need for public participation and the degree of complexity in undertaking the new work while maintaining satisfactory *Security* and quality of supply on the existing TS.

13.2. VOLTAGE LIMITS AND TARGETS

13.2.1. The target voltages for planning purposes are as in Table 7 below

Table 7: Target Voltages for Transmission Planning Purposes

Minimum steady state voltage on any bus not supplying a <i>customer</i>	
With multiple feeder supplies:	0.95 Vn
With single feeder supplies and after contingency for multiple feeder supplies:	0.90 Vn
Maximum harmonic voltage distortion caused by <i>customer</i> at PCC:	Electricity By- Law Tenth schedule standard 3.6 QOS for Transmission Refer to the standard IEC 61000
Maximum negative sequence voltage caused by <i>customer</i> at PCC:	To be agreed amongst participants
Maximum voltage change due to load varying N times per hour:	$(4.5 \text{ LOG}_{10} N)\%$ of Vn

Maximum voltage decrease for a 5% load increase at receiving end of system (without adjustment):	0.05 V_n
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13.3. OTHER TARGETS FOR TRANSMISSION PLANNING PURPOSES

13.3.1. Transmission System Lines: Thermal ratings of standard TS lines shall be determined and updated from time to time. The temperatures used are 80°C for aluminium conductor steel reinforced lines providing a firm supply (under single contingencies), and 75°C for lines of copper or aluminium alloy or aluminium conductor steel reinforced lines not providing a firm supply. The thermal ratings shall be used as an initial check of line overloading. If the limits are exceeded the situation shall be investigated as it may be possible to defer strengthening depending on the actual line and on local conditions.

13.3.2. Transformers: Standard transformer ratings shall be determined according to site conditions and updated from time to time using IEC specifications. The permissible overload of a specific transformer depends on load cycle, ambient temperature and other factors. If target loads are exceeded the specific situation shall be assessed as it may be possible to defer adding extra transformers, depending on the actual transformer and on load conditions.

13.3.3. Series Capacitors

- a) With the system healthy, the maximum steady state current should not exceed the rated current of the series capacitor.
- b) IEC 143 standards call for cyclic overload capabilities as follows:
 - b.1) 8 hours in a 12-hour period: 1.1 times rated current
 - b.2) ½ hour in a 6 hour period: 1.35 times rated current
 - b.3) 10 minutes in a 2 hour period: 1.5 times rated current
- c) In addition, the Transmission Licensee may require, informing the Single Buyer accordingly, an occasional over-current rating of: 2 hours once per year: 1.3 times rated current;
- d) The particular rating to be used must match the duration of the contingency with the required overload capability. Duration of contingency will depend on ability to pick up generation or shed load and the load profile.

13.3.4. Shunt Reactive Compensation

- a) Shunt capacitors shall be able to operate at 30% above their nominal rated current at V_n to allow for harmonics and voltages up to V_m .
- b) Reactive compensation, whether new or modified, may cause harmonic resonance problems. Any Participant wishing to install or modify such equipment shall at his expense arrange for harmonic resonance studies to be conducted. If such studies indicate possible harmonic resonance conditions which could impact on the TS, such Party shall inform the System and Market Operator before proceeding with the installation or modification.

13.3.5. Circuit Breakers

- a) Normal and fault current ratings for standard switchgear are determined and updated from time to time. These ratings, and the following limits specified for circuit breakers, shall not be exceeded:
 - a.1) Single-phase breaking current: 1.15 times 3 phase fault current
 - a.2) Peak making current: 2.5 times 3 phase rms fault current

13.3.6. Secondary arc current during single-phase re-closing

- a) The secondary arc current shall not exceed:
 - a.1) 20 amps rms with recovery voltage of 0.4 p.u
 - a.2) 40 amps rms with recovery voltage of 0.25 p.u

13.4. CONTINGENCY CRITERIA FOR TRANSMISSION PLANNING PURPOSES

- 13.4.1. A system cannot be made 100% reliable as planned and *forced outages* of components will occur, and multiple outages are always possible, despite having a very low probability of occurrence. From an economic point of view optimum reliability is obtained when the cost involved in reducing the load not supplied by one kW is just equal to the value of this unsupplied kW to the economy or to the specific *User* involved. The appropriate degree of reliability depends on the probability of loss of supply and the probable amount of load not supplied when an outage does occur.
- 13.4.2. The *Single Buyer* shall formulate long-term plans for expanding or strengthening the *TS* on the basis of the justifiable redundancy.
- 13.4.3. A system meeting the n-1 or n-2 contingency criterion must comply with all relevant limits outlined in 7.4.1 (voltage limits) and the applicable current limits, under all credible system conditions.
- 13.4.4. For contingencies under various loading conditions it shall be assumed that appropriate, normally-used, generating plant is in service to meet the load and provide *Spinning Reserve*. For the more probable n-1 network contingency the most unfavourable generation pattern within these limitations shall be assumed, while for the less probable n-2 network contingency an average pattern shall be used.

13.5. CRITERIA FOR POWER STATIONS INTEGRATION

- 13.5.1. With all connecting lines healthy it shall be possible to transmit the total output of the *Power Station* to the system for any system load condition. If the local area depends on the *Power Station* for voltage support, connection shall be done with a minimum of two lines.
- 13.5.2. Transient stability shall be maintained following a successfully cleared single phase fault where economically justifiable.
- 13.5.3. If only a single line is used it shall be able to be selected to alternative *busbars* and be able to go on to bypass at each end of the line.

13.6. TRANSIENT STABILITY

- 13.6.1. Transient stability shall be maintained for the following conditions:
- a) a three-phase, line or Busbar fault, cleared in normal Protection times, with the system healthy and the most onerous Power Station loading condition, or
 - b) a single phase fault cleared in "bus trip" times, with the system healthy and the most onerous Power Station loading condition, or
 - c) a single-phase fault, cleared in normal Protection times, with any one line out of service and the Power Station loaded to average availability.

13.7. BUSBAR ARRANGEMENTS

- 13.7.1. *Busbar* layouts shall allow for selection to alternative *busbars* and the ability to go on to bypass, and not more than 1000 MW of generation shall be connected to any bus section, even with one bus section out of service.

13.8. SPECIAL CUSTOMER REQUIREMENTS FOR INCREASED RELIABILITY

- 13.8.1. Should a *User* require a more reliable connection than the one provided for by the *Single Buyer* in the *integrated generation and transmission plan*, and the *User* is willing to pay the total cost of providing the increased reliability, the *Single Buyer* may agree to the proposed requirements.

PART 4: SYSTEM OPERATIONS CODE

SECTION 14: OPERATION OF THE IPS

14.1. INTRODUCTION

14.1.1. This Part sets out the responsibilities and roles of the Single Buyer, the Transmission Licensee, the System and Market Operator and the Users as far as the operation of the *Interconnected Power System (IPS)* is concerned, and more specifically issues related to:

- a) Reliability, Security and safety;
- b) Ancillary Services;
- c) Market operation actions required by the System and Market Operator;
- d) Independent actions required and allowed by Users;
- e) Operation of the IPS under abnormal conditions; and
- f) Field operation, maintenance and maintenance co-ordination / outage planning.

14.2. RESPONSIBILITIES OF THE SYSTEM AND MARKET OPERATOR

14.2.1. The System and Market Operator shall be responsible for the safe and efficient operation of the IPS during normal conditions. In order to do this, the System and Market Operator shall be responsible for determining and dispatching the capacity needed to supply the required Ancillary Services.;

14.2.2. The System and Market Operator shall operate the IPS in accordance with the provisions of this Grid Code and the Market Rules;

14.2.3. The System and Market Operator shall have ultimate authority and accountability for the operation of the IPS;

14.2.4. The System and Market Operator is responsible for ensuring that load-generation balance is maintained during Emergency States and for directing the Transmission System recovery efforts following these emergency conditions.

14.2.5. The System and Market Operator is responsible for controlling the Transmission System voltage variations during Emergency States through a combination of direct control and timely instructions to Generators and other Users.

14.2.6. In case a Single Outage occurs in the Grid, the System and Market Operator is responsible for implementing reasonable system adjustments to assure that in case new Single Outage contingency occurs the system:

- a.1) Remains stable and without risk of Cascading Outages;
- a.2) Grid Frequency stabilizes within the limits of [49.0 and 51.0] Hz;
- a.3) Voltages at all Point of connections are within the limits [0.90 and 1.10] of the nominal value and no risk of voltage collapse exist;
- a.4) Permanent overloads in any transmission line or substation Equipment does not exceed [115%] of the maximum continuous ratings.

14.2.7. In order to comply with clause PART 4: 14.2.6 the System and Market Operator shall implement all the necessary adjustments including network re-configuration and generation re-dispatch. It can also instruct manual load dropping in cases the previous mentioned actions proved to be insufficient.

14.2.8. The System and Market Operator is responsible for performing all necessary studies to determine the safe operating limits that will secure the IPS against any instability problems, including those due to Multiple Outage Contingencies.

14.2.9. All Participants shall co-operate in setting up operational procedures under the direction of the System and Market Operator to ensure proper operation of the IPS;

14.2.10. SAPP and other international tie-line operations shall be governed by the SAPP and related operating agreements and guidelines.

14.3. RESPONSIBILITIES OF THE TRANSMISSION LICENSEE

14.3.1. The Transmission Licensee is responsible for providing and maintaining all Transmission System equipment and facilities, including those required for maintaining Power Quality.

14.3.2. The Transmission Licensee is responsible for designing, installing, and maintaining the Transmission System protection system that will ensure the timely disconnection of faulted facilities and equipment.

14.3.3. The Transmission Licensee is responsible for ensuring that safe and economic Transmission System operating procedures are always followed.

14.3.4. The TL shall be responsible in ensuring that its power system will not cause degradation of the User's system. It shall also be responsible in undertaking all necessary measures to remedy any degradation of the user's system that the TS has caused.

14.3.5. The Transmission Licensee is responsible for executing the instructions of the System and Market Operator to ensure the Power Quality in the Transmission System.

14.4. RESPONSIBILITIES OF GENERATORS

14.4.1. The Generator is responsible for maintaining its Generating Units to fully deliver the capabilities declared in its Connection Agreement, depending on the availability of the primary resource in case of VRE generation.

14.4.2. The Generator is responsible for providing accurate and timely planning and operations data to the Single Buyer, Transmission Licensee and System and Market Operator.

14.4.3. The Generator shall be responsible for ensuring that its Generating Units will not disconnect from the Transmission System during disturbances except when:

- a) The Frequency or Voltage Variation would damage Generator's equipment; or
- b) The Frequency or Voltage Variation is outside the prescriptions contained in Section Section 7.; or
- c) When the System and Market Operator has agreed for the Generator to do so.

14.4.4. The Generator is responsible for executing the instructions of the System and Market Operator during emergency conditions.

14.4.5. The Generator is responsible for controlling Generator voltage or adjusting its reactive power output, in accordance with the instructions issued by the System and Market Operator.

14.5. RESPONSIBILITIES OF OTHER TS USERS

14.5.1. The User is responsible for assisting the System and Market Operator in maintaining Power Quality in the TS during normal conditions by correcting any User facility that causes Power Quality problems.

14.5.2. The User shall be responsible in ensuring that its power system will not cause the degradation of the TS. It shall also be responsible in undertaking all necessary measures to remedy any degradation of the TS that its system has caused.

14.5.3. The User is responsible for providing and maintaining voltage-control Equipment on its system to support the voltage at the Point of connection.

14.5.4. The User is responsible for executing the instructions of the System and Market Operator during Alert or Emergency conditions.

14.6. SYSTEM RELIABILITY AND SAFETY

14.6.1. The IPS shall be operated to achieve the highest degree of reliability practicable and appropriate remedial action shall be taken promptly to remedy any abnormal condition that may jeopardise reliable operation. Power transfers as determined by the scheduling arrangements in accordance with the Market Rules, and other transfers as far as feasible, shall be adjusted as required to achieve or restore reliable IPS operation;

14.6.2. Voltage control, operating on the IPS and Security monitoring shall be co-ordinated on a system - wide basis in order to ensure safe, reliable, and economic operation of the IPS;

14.6.3. During or after a system disturbance, high priority shall be given to keeping all synchronised units running and connected to the IPS, or islanded on their own auxiliaries, in order to facilitate system restoration;

14.6.4. Black start services shall be provided as available from units;

14.6.5. The System and Market Operator shall make all reasonable measures to retain system interconnections unless it becomes evident that continued parallel operation of the affected parts of the IPS would jeopardise the remaining system or damage equipment;

14.6.6. Should it become unsafe to operate units in parallel with the system when critical levels of frequency and voltage result on the IPS from a disturbance, the separation and/or safe shut down of units shall be accomplished in such a way as to minimize the time required to re-synchronise and restore the system to normal;

14.6.7. In the event of a system separation, the System and Market Operator shall ensure that the part of the IPS with a generation deficit shall automatically remove sufficient load to permit early recovery of voltage and frequency so that system integrity may be re- established;

14.6.8. Customer load shall be shed for a reasonable period of time rather than risking the possibility of a cascading failure or operating at abnormally low frequency or voltage for an extended period of time; and

14.6.9. An internationally Interconnected power System and Market Operator may request that the System and Market Operator takes any available action to increase or decrease the active energy transfer into or out of its external system by the way of emergency assistance. Such requests shall be met by the System and Market Operator providing it has the capability to do so.

14.7. SYSTEM SECURITY

14.7.1. The IPS shall be operated as far as practical so that instability, uncontrolled separation or cascading outages do not occur as a result of the most severe double contingency. Multiple outages of a credible nature shall be examined and, whenever practical, the IPS shall be operated to protect it against instability, uncontrolled separation and cascading outages.

14.7.2. The System and Market Operator shall develop and periodically update the plan action to restore the system in an orderly manner in the event of partial or total shutdown. This plan shall be coordinated with other participants to ensure consistent interconnection restoration

14.7.3. The System and Market Operator shall operate and maintain primary and emergency control centre and facilities to ensure continuous operation of the IPS.

14.8. OPERATIONAL MEASURES

14.8.1. Operating instructions, procedures, standards and guidelines shall be established to cover the operation of the IPS under all system conditions.

14.8.2. The IPS shall, as far as reasonably possible, be operated within defined technical standards and equipment ratings.

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- 14.8.3. The System and Market Operator shall manage constraints on the TS through the determination of operational limits and the dispatch out of merit generation if necessary to maintain system security.
- 14.8.4. To achieve a high degree of service reliability, the System and Market Operator shall ensure adequate and reliable communications between all control centres, Power Stations and substations. Communication facilities to be provided and maintained by Users are specified in the Information Exchange Code.
- 14.8.5. The System and Market Operator shall be responsible for the determination of the TS Protection philosophy (as contrasted to equipment Protection) by means of applicable analytical studies.
- 14.8.6. The System and Market Operator shall determine and review, whenever there are system configurations changes, relay settings for main and back-up Protection on the IPS.

14.9. OPERATIONAL AUTHORITY

- 14.9.1. The System and Market Operator shall have operational authority over the TS. Operational authority for other networks shall lie with the respective asset owners.
- 14.9.2. Normal control of the various networks shall be in accordance with the operating procedures as agreed between the Participants.
- 14.9.3. Except where otherwise stated in this section, no Participant shall be permitted to operate the equipment of another without the permission of such other Participant. In such an event the asset owner shall have the right to test and authorise the relevant operating staff in accordance with his own standards before such permission is granted.
- 14.9.4. Notwithstanding the provisions of section 2.1, Participants shall retain the right to safeguard the health of their equipment.

14.10. OPERATING PROCEDURES

- 14.10.1. The *System and Market Operator (SMO)* shall develop and maintain operating procedures for the safe operating of the TS, and for assets *connected to the TS*. These operating procedures shall be adhered to by *Participants* when operating equipment on the TS or *connected to the TS*; SMO shall ensure that the procedures are accessible by all the participants.
- 14.10.2. Each *User* shall be responsible for his own safety rules and procedures. The *System and Market Operator* shall ensure the compatibility with regard to the safety rules and procedures of all *Participants*. However, if a dispute affecting the interpretation and/or application of safety rules and procedures should arise, such dispute shall be resolved in accordance with the procedures specified by the *System and Market Operator*;
- 14.10.3. Operating instructions and procedures shall be established by the System and Market Operator and participants to enable operation to continue during the loss of telecommunication facilities; and
- 14.10.4. The *SAPP* operating agreements and guidelines shall apply in the case of operational liaison with all international power systems *connected to the TS*.

14.11. OPERATIONAL LIAISON, PERMISSION FOR SYNCHRONISATION

- 14.11.1. The *System and Market Operator* shall sanction the switching, including shutting down and synchronising, of *units* and changing over of auxiliaries on all units.
- 14.11.2. If any *Participant* experiences an *emergency*, the other *Participants* shall assist to an extent as may be necessary to ensure that it does not jeopardise the operation of the networks/plant.

14.11.3. A *User* shall enter into an operating agreement with the *System and Market Operator*, if it is physically possible to transfer load or embedded *generators* from one *Point of connection* to another by performing switching operations on his network. This operating agreement (to be developed by MERA) shall cover at least the operational communication and notice period requirements and switching procedures for such load transfers.

14.12. EMERGENCY AND CONTINGENCY PLANNING

14.12.1. The System and Market Operator shall develop and maintain contingency plans to manage system contingencies and emergencies that are relevant to the performance of the IPS. Such contingency plans shall be developed in consultation with all Participants, shall be consistent with internationally acceptable utility practices, and shall include but not be limited to -

- a) Under-frequency load shedding;
- b) Meeting disaster management requirements including the necessary minimum load requirements;
- c) Forced outages at all points of interface; and
- d) Supply restoration.

14.12.2. Emergency plans shall allow for quick and orderly recovery from a partial or complete system collapse, with minimum impact on Users;

14.12.3. Emergency plans shall comply with SAPP agreements and guidelines;

14.12.4. All contingency/emergency plans shall be periodically verified by actual tests to the greatest practical extent, as agreed by the parties, without causing undue risk or undue cost. The costs of these tests shall be borne by the respective asset owners. The System and Market Operator shall ensure the coordination of the tests in consultation with all affected Participants;

14.12.5. The System and Market Operator shall specify minimum emergency requirements for Distribution Licensee control centres, Power Station local control centres and substations to ensure continuous operation of their control, recording, enunciator and communication facilities;

14.12.6. Other Participants shall comply with the System and Market Operator's requirements for contingency and emergency plans;

14.12.7. Automatic and Manual Load Shedding schemes shall be made available under the direction of the System and Market Operator;

14.12.8. The System and Market Operator shall be responsible for determining all operational limits on the TS by means of the applicable analytical studies;

14.12.9. Load flow studies shall be conducted regularly to determine the effect that various component failures would have on the reliability of the IPS. At the request of the System and Market Operator, Distribution Licensees shall perform related load flow studies on their part of the network and make the results available to the System and Market Operator.

SECTION 15: ANCILLARY SERVICES (NOT CURRENTLY ON THE MARKET)

15.1. ANCILLARY SERVICES CATEGORIES

15.1.1. The following services are defined as Ancillary Services:

- a) Operating reserves
- b) Black Start and Islanding
- c) Reactive power compensation and voltage control from units
- d) Near 50Hz Resonance Control Service

15.1.2. Operating reserves

Operating reserves are required to secure capacity that will be available for reliable and secure balancing of supply and demand. There shall be three categories of operating reserves: Spinning Reserve (Primary Reserve), Regulating Reserve (Secondary Reserve) and Quick Reserve (Tertiary Reserve).

- a) Spinning Reserve (Primary Reserve)

Spinning (Primary) reserve is the reserve provided by Generating Units which is activated automatically in case of frequency changes due to the action of the speed governors.

- b) Regulating Reserve (Secondary Reserve)

Regulating Reserve is reserve that is under AGC control and can be activated within 10 seconds and be fully deployed within 10 minutes of activation. The Generation Units providing Regulating Reserve shall operate under AGC and shall be able to alter their generation or load under AGC to the performance requirements specified by the System and Market Operator.

15.1.3. Quick Reserve (Tertiary Reserve)

Quick Reserve (Tertiary Reserve) is a reserve that can be activated, on request, within 10 minutes and must be sustainable for at least two hours. Quick Reserve can be provided either by synchronized Generating Units or by Fast Start Generating Units;

15.1.4. Black start and Islanding

- a) Islanded units shall be capable of running in the islanded state for at least two hours and of re-connecting to the network.
- b) All units capable of Islanding are required to provide the service to the System and Market Operator. Units capable of Islanding shall be certified by the System and Market Operator.
- c) To ensure optimal operation of the IPS, the System and Market Operator may deploy network Islanding schemes on the network, e.g. an out-of-step tripping scheme.
- d) The System and Market Operator shall determine the minimum requirements for each black start supplier and ensure that the contracted suppliers are capable of providing the service.

15.1.5. Reactive power compensation and voltage control from units

- a) Voltage control and the supply or consumption of reactive power is inter-related in the sense that the voltage is affected by changes in the reactive power flow. System stability depends on the voltage profile across the system. In view of these considerations it is necessary from time to time to employ certain Power Stations to supply or consume reactive power whether or not they are producing active power, for the purpose of voltage control.
- b) The amount of reactive power supplied or consumed shall be controlled by the System and Market Operator. This may be done directly through the Energy Management System or by telephone.
- c) When a unit is generating or pumping, reactive power supply is mandatory in the full operating range as specified in the Network Code.

15.1.6. Near 50 Hz Resonance Control Service

Some plant may be required to run in Synchronous Condenser (SCO) mode in order to add fault level to the TS. The main reason for this is to assist with the shifting of the near 50 Hz resonance in the network upwards from 50 Hz. The Contracts with plants which will be able and selected by the SB to provide this service shall reflect the cost of this provision in the Contract financial clauses.

15.2. ANCILLARY SERVICES REQUIREMENTS

15.2.1. Reference Incident.

- a) Every year, the System and Market Operator shall define and propose to MERA for approval, the Reference Incident which, if considered appropriate, could be different in cases of peak and load demand.
- b) This Reference Incident will be used by the System and Market Operator to size the needs of Spinning (Primary), Regulating (Secondary) and Quick (Tertiary) Reserves.

15.2.2. Amount of Reserves required when not connected to the SAAP

- a) The amount of Spinning (Primary) Reserve will be, at least, the power generation needed to maintain the frequency, after the occurrence of the Reference Incident between 49.5 and 50.5 Hz.
- b) The minimum amount of Regulating (Secondary) Reserve shall be:
 - b.1) The amount of power generation needed to continuously balance generation and load, under the control of the AGC, while keeping frequency as close as possible to its nominal value (50 Hz), while the system is in Normal State; or
 - b.2) The amount of power generation needed to compensate the short term fluctuation of VRE Generation plus the errors in the VRE Generation forecasts; or
 - b.3) The amount of power generation needed to restore Spinning (Primary) Reserve within 10 minutes after the occurrence of the Reference Incident;whichever is larger.
- c) The amount of Regulating (Secondary) plus Quick (Tertiary) reserve will be the power generation needed to recover the frequency to nominal value (50 Hz) in 30 minutes or less, after the occurrence of the Reference Incident.

15.2.3. Voltage control

15.2.4. The *System and Market Operator* is responsible for the voltage control in the Transmission System as well as at the interface between the *Transmission Licensee* and its *Users*;

15.2.5. The System and Market Operator shall determine the amount of Reactive Power needed to be absorbed or supplied by Generating Units in order to control voltage in the Transmission System.

15.2.6. The System and Market Operator shall also utilize all available equipment from the Transmission Licensee to control voltage across the Transmission System. These equipment may include, among others, on-load transformer tap changers, shunt reactor or capacitors, SVC, et.

15.2.7. Amount of Reserves required when interconnected to the SAAP

- a) In the event of interconnection with SAPP, the Spinning (Primary) and Regulating (Secondary) Reserve requirement shall be governed by the ABOM and the SAPP Operating guidelines.

15.3. TECHNICAL REQUIREMENTS FOR PROVIDING ANCILLARY SERVICES

- 15.3.1. Regulating (Primary) Reserve: To provide regulation reserve a generator must be capable of varying its output, up or down, in response to a deviation in system frequency by the action of the unit speed governor. This Ancillary Service is mandatory for all Generating Units, unless exempted by the System and Market Operator.
- 15.3.2. Regulating (Secondary) Reserve: To provide Regulating (Secondary) reserve a generator must be able to ramp up or down its generation, to its full output power or technical minimum, in response to an automatic signal provided by the System and Market Operator. The SMO will specify the technical conditions requested to units and specially the minimum ramp up or down speed (MW/min) and the minimum reserve margin to raise or lower (MW). The SMO will also specify the technical conditions of the signal, send to the RTU and to be integrated to the unit control system.
- 15.3.3. Quick (Tertiary) Reserve: To provide Quick (Tertiary) Reserve a generator must:
- a) Be capable to ramp up or down its generation, within 15 minutes, after receiving an order by the System and Market Operator; and
 - b) Be synchronized (on-line) or have Fast Start capability
- 15.3.4. Voltage regulation: To provide reactive power a generator must be capable of varying the reactive power output in response to a request from the SMO. Participation of the units into the Voltage Control is mandatory for all Generating units. Also, the Transmission Licensee shall facilitate the tap changers and shunt devices participation into de Voltage Control, which is mandatory.
- 15.3.5. Black Start: To provide black start a generator must be capable of starting its generation from cold without any external power supply, and capable of connecting to and supplying the Transmission System with electricity once started. The Single Buyer, in consultation with the SMO will specify the units that shall be required to provide this service which is not remunerated.

15.4. SCHEDULING OF GENERATION AND ANCILLARY SERVICES PROCUREMENT

- 15.4.1. The System and Market Operator shall determine the minimum amount (numerical values) of Spinning (Primary), Regulating (Secondary) and Quick (Tertiary) Reserves required to securely operate the system, under different operational conditions. These values shall be submitted to MERA for approval.
- 15.4.2. The System and Market Operator shall provide a day-ahead demand forecast for the IPS.
- 15.4.3. The System and Market Operator will develop the daily twenty-four hours (24) day-ahead energy schedule from 16:00CAT each day, in accordance with the prescriptions of the Market Rules. Should a deviation exist between the scheduled and actual load conditions the System and Market Operator shall be responsible for taking remedial action.
- 15.4.4. The System and Market Operator shall produce the Day Ahead dispatch, as required by the Market Rules, taking due consideration of the amounts of Spinning (Primary), Regulating (Secondary) and Quick (Tertiary) Reserves required.
- 15.4.5. The System and Market Operator shall continuously monitor the amount of reserves existing during real time operations and it may produce the necessary changes or re-dispatch if Spinning, Regulating or Quick reserves fall below the required values.
- 15.4.6. Ancillary services procurement shall be the responsibility of the Single Buyer, provided that during the Single Buyer Phase, as indicated in the Market Rules, the Ancillary Services provided by generators will be included in the PPAs signed between the Single Buyer and the generators. The Single Buyer shall procure the required Ancillary Services that are economically efficient and needed to provide the required reliability, following the recommendations of the System Operation and in accordance with the Market Rules.
- 15.4.7. Ancillary services scheduling and execution shall be a System and Market Operator responsibility.

15.4.8. Rescheduling of Ancillary Services during unplanned events shall be undertaken by the System and Market Operator as necessary to maintain system reliability, security and safety.

SECTION 16: IPS OPERATING STATES AND OPERATING CRITERIA

16.1. IPS OPERATING STATES

16.1.1. The IPS shall be considered to be in the Normal State when:

- a) The system frequency is within the limits of 49.7 and 50.3 Hz;
- b) The Primary, Secondary and Tertiary reserves are within the values established in Sub-Section 15.2;
- c) The voltages at all Point of connections are within the 0.95 and 1.05 of the nominal voltage;
- d) The loading levels of all transmission lines and substation equipment are below 100% of the maximum continuous ratings.
- e) The Single Outage Criterion (N-1) is met. This criterion specifies that the IPS, following the loss of one Generating Unit, transmission line, or transformer shall be capable to operate with:
 - e.1) No risk of Cascading Outages or Grid instability;
 - e.2) System frequency remains within the limits of [49.5 and 50.5] Hz;
 - e.3) Voltages at all Connection Points are within the limits [0.9 and 1.1] of the nominal value;
 - e.4) No permanent overloads in any transmission lines or substation equipment. Transitory overloads are permitted provided that:
 - e.5) They do not exceed [115%] of the maximum continuous ratings; and
 - e.6) Can be corrected through network re-configuration or Generation re-dispatch.

16.1.2. The IPS shall be considered to be in the Alert State when any one of the following conditions exists:

- a) The Primary, Secondary and Tertiary reserves are less the values established in Sub-Section 15.2;
- b) The voltages at the Point of connections are outside the limits of 0.95 and 1.05 but within the limits of 0.90 and 1.10 of the nominal value;
- c) There is Critical Loading or imminent overloading of transmission lines or substation Equipment;
- d) Peace and order problems exist, which may pose a threat to IPS operations.

16.1.3. The IPS shall be considered to be in the Emergency State when a Multiple Outage Contingency has occurred without resulting in Total System Blackout, and any one of the following conditions exists:

- a) There is generation deficiency;
- b) Grid transmission voltages are outside the limits of 0.90 and 1.10; or
- c) The loading level of any transmission line or substation Equipment is above 110% of its continuous rating.

16.1.4. The IPS shall be considered to be in the Extreme State when the corrective measures undertaken by the System and Market Operator during an Emergency State failed to maintain System Security and resulted in cascading outages, islanding, and/or power system voltage collapse.

16.1.5. The Grid shall be considered to be in Restorative State when Generating Units, transmission lines, substation equipment, and loads are being energized and synchronized to restore the IPS to its Normal State.

16.2. COMMUNICATION OF SYSTEM CONDITIONS AND OPERATIONAL INFORMATION

- 16.2.1. The *System and Market Operator* shall determine system conditions from time to time, and communicate these, or changes from a previous determination, to all *Participants*.
- 16.2.2. These system conditions shall typically be based on a steady state and/or dynamic simulation of the *IPS* and include measures that will enhance reliability.
- 16.2.3. The *System and Market Operator* shall be responsible for providing *Participants* with operational *information* as may be agreed from time-to-time and as specified in the Information Exchange Code. This shall include information regarding planned *and forced outages* on the *IPS* as determined by the market rules.

16.3. IPS OPERATING CRITERIA

- 16.3.1. The System and Market Operator shall make its best endeavours to operate the *IPS* in the Normal State.
- 16.3.2. The security and reliability of the *IPS* shall be based on the Single Outage Contingency criterion. This criterion specifies that the Grid shall continue to operate in the Normal State or Alert State following the loss of one Generating Unit, transmission line, or transformer.
- 16.3.3. Following the first contingency (N-1 condition), the System and Market Operator may implement reasonable system adjustments to prepare for the next contingency producing network re-configurations and generation re-dispatch, with manual load dropping as the last resort.
- 16.3.4. The *IPS* frequency shall be controlled by the utilization of the Regulating Reserve and Quick Reserves during Normal or Alert States, and by the timely use of manual load shedding during Emergency States.
- 16.3.5. The Transmission System voltage shall be maintained at a safe level to reduce the vulnerability to transient instability, dynamic instability and/or voltage instability problems.
- 16.3.6. In Alert or Emergency States, the SMO shall implement corrective actions it considers appropriate until the abnormal condition is corrected. The corrective action may include both supply-side and demand-side options. Where possible, warnings shall be issued by the System and Market Operator on expected utilization of any contingency resources.
- 16.3.7. The System and Market Operator shall have a designated person to refer to in periods of abnormal operation, in particular while in Emergency State.
- 16.3.8. The order in which resources are to be used during Alert or Emergency State may change from time to time. An updated list shall be issued by the System and Market Operator.
- 16.3.9. Adequate automatic under-frequency systems shall be kept armed at all times.

16.4. OPERATION OF VRE GENERATORS

SMO to determine and place the procedures for operating RES

16.5. INDEPENDENT ACTION BY PARTICIPANTS

- 16.5.1. Each Participant shall have the right to reduce or disconnect a Point of connection under emergency conditions if such action is necessary for the Protection of life or equipment. Advance notice of such action shall be given where possible and no financial penalties shall apply for such action.
- 16.5.2. In Alert or Emergency States that require load shedding, the request to shed load shall be initiated immediately, in accordance with agreed procedures.

16.5.3. Following such emergency operations as may be necessary to protect the integrity of the IPS or the safety of equipment and human life, the Participants shall work diligently towards removing the cause of the emergency and the supply shall be reconnected immediately after the emergency conditions have passed.

16.6. RISK OF TRIP

16.6.1. *Generators* shall identify and report all tripping risks to the *System and Market Operator*.

16.6.2. *Participants* shall minimise the risk of tripping / loss of output on their own plant and equipment, associated with their operation and maintenance.

16.6.3. Special care shall be taken by all *Participants* when planning or executing work on *Protection* panels. The normal outage process described in the maintenance coordination / outage planning section shall be followed. All such work shall be treated as *Risk-related Outages* by the *System and Market Operator*.

16.6.4. When a risk of trip of equipment or loss of output with an impact exceeding 5MW could occur on any part of the *IPS*, owing to such operation and maintenance, the affected *Participants* shall be consulted as to who shall accept the risk before work may commence. The *System and Market Operator* shall always be informed of such events and shall in general coordinate these requests and accept the risks.

16.6.5. The affected *Participants* shall be informed when the risk has been removed.

16.7. GRID OPERATIONS NOTICES AND REPORTS

16.7.1. Grid Operations Notices

- a) The following notices shall be issued, without delay, by the System and Market Operator to notify all Users of an existing alert state:
 - a.1) Yellow Alert: When the sum of Regulation plus Quick Reserve is less than the capacity of the largest synchronized Generating Unit or power import from a single interconnection, whichever is higher;
 - a.2) Red Alert when the sum of Regulation plus Quick Reserve is zero or a generation deficiency exists or if there is Critical Loading or Imminent Overloading of transmission lines or equipment;
 - a.3) Security Red Alert when peace and order problems exist, which may affect Grid operations.
- b) A Significant Incident Notice shall be issued by the System and Market Operator, the Transmission Licensee or any User if a Significant Incident has transpired on the TS or the power system of the User, as the case may be. The notice shall be issued within 15 minutes from the occurrence of the Significant Incident, and shall identify its possible consequences on the TS and/or the other Users and any initial corrective measures that were undertaken by the System and Market Operator, the Grid Owner, or the User, as the case may be.

16.7.2. Grid Operations Reports

- a) The Transmission Licensee and the System and Market Operator shall prepare and submit to the MERA weekly reports on IPS operation. These reports shall include an evaluation of the events and other problems that occurred within the IPS for the previous week, the measures undertaken by the Transmission Licensee and the System and Market Operator to address them, and the recommendations to prevent their recurrence in the future.
- b) The Transmission Licensee and the System and Market Operator shall prepare and submit to the MERA quarterly and annual operations reports. These reports shall include the Significant Incidents that had a material effect on the TS or the system of any User.
- c) The Transmission Licensee, Generators and other Users shall be responsible for providing relevant information to the System and Market Operator in its preparation of the mentioned reports.

16.7.3. Fault reporting and analysis/incident investigation

- a) Generators shall report loss of output and tripping of units and governing to the System and Market Operator within 15 minutes of the event occurring.
- b) Distribution Licensees and Bulk Supply Customers shall report the loss of major loads (>5MVA) to the System and Market Operator within 15 minutes of the event occurring. Warning of the reconnection of such loads shall similarly be given with at least 15 minutes advance notice.
- c) Incidents on the IPS involving sabotage or suspected sabotage, as well as threats of sabotage shall be reported to the System and Market Operator.
- d) Any incident that materially affected the quality of the service to another Participant shall be formally investigated. These include interruptions of supply, disconnections, under or over voltage incidents, quality of supply contraventions, etc. A preliminary incident report shall be available after three working days and a final report within three months. The System and Market Operator shall initiate such an investigation, arrange for the writing of the report and involve all affected Participants. All these Participants shall make all relevant required information available to the System and Market Operator. The confidentiality status of information is described in the Information Exchange Code.
- e) A Significant Incident shall have the following additional requirements:
 - e.1) Any Participant shall have a right to request an independent audit of the report, at their own cost, if they are not satisfied with it.
 - e.2) Recommendations shall be implemented by the Participants within the time frames specified above
- f) Incidents shall be reported to MERA as defined in the licensing requirements.
- g) System and Market Operator shall be responsible for developing and maintaining adequate records of fault statistics.

SECTION 17: MAINTENANCE COORDINATION, OUTAGE SCHEDULING & COMMISSIONING

17.1. OBJECTIVE

17.1.1. Optimal reliability of the IPS shall be achieved by co-ordinating scheduled outages of generation, transmission, distribution, bulk supply and any facility affecting IPS. The maintenance coordination / outage planning shall be done in collaboration with the System and Market Operator and the Single Buyer.

17.2. DEFINITION OF ROLES AND RESPONSIBILITIES

17.2.1. Outage Requester

An outage requester is a person requesting an outage on plant for planned maintenance, repairs, auditing, emergency repairs, construction, refurbishment, inspection, testing or to provide safety clearance for other activities such as servitude clearance, line crossings and underpasses. This shall be a Distribution Licensee, Generator, Bulk Supply Customer or the Transmission Licensee employee or agent, formally nominated.

17.2.2. The Transmission Licensee Outage Scheduler

The Transmission Licensee outage scheduler is a person appointed by the Transmission Licensee to check for multiple requests for an outage of the same network unit. If another outage request for the same bay(s) is noticed, the Transmission Licensee outage scheduler requests the parties involved to combine their requests into a single outage. In the case of conflicting outages, the Transmission Licensee outage scheduler considers the priority and relative urgency of the requests and reflects this against the validated request. The Transmission Licensee outage scheduler is also responsible for ensuring that negotiations of Risk-related Outages have taken place.

17.2.3. System and Market Operator Outage Scheduler

The System and Market Operator outage scheduler is appointed to assess the viability of a scheduled outage and either to confirm or to turn down the request. This scheduler shall optimise plant utilisation by evaluating network load capabilities, different system configurations and risk factors. It is also the responsibility of the scheduler to co-ordinate and schedule plant that affects international customers.

17.2.4. System and Market Operator Shift Controller

The System and Market Operator controller on shift at the time of the outage is responsible for finally sanctioning (or alternatively refusing) the outage and ensuring that the relevant operating instructions are issued.

17.3. OUTAGE PROCESS

17.3.1. The *System and Market Operator* shall develop and maintain an electronic *TS* maintenance *Scheduling* system for the coordination of all *TS* outages.

17.3.2. The *Transmission Licensee* shall inform all *Users* of the name and contact details of the respective *Transmission Licensee* outage scheduler(s) in the different geographic parts of the country.

17.3.3. The *System and Market Operator* shall make available to *Users* a schedule of all *Planned Outages* on the *TS*. The outage schedule shall cover a period of one year rolling and shall indicate the status of the outage, i.e. whether confirmed or not.

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- 17.3.4. When the need for an outage is first identified it shall be entered into a *Transmission* maintenance *Scheduling* system as a requested outage with *Planned Outage* dates, times, reason, type of maintenance and request urgency assigned to it. The outage requester shall enter this request into the maintenance *Scheduling* system if the requester has access to this system. If no access is available, the requester shall contact the relevant *Transmission Licensee* outage scheduler or the *System and Market Operator* outage scheduler with the request at least 14 days prior to scheduled date of the outage.
- 17.3.5. When the *Transmission Licensee* outage scheduler is satisfied with the request(s) and, in the case of a calculated risk, has ensured that negotiation has taken place with the relevant *Stakeholders* this scheduler shall mark it as a scheduled outage.
- 17.3.6. At this point the *System and Market Operator* outage scheduler shall confirm the outage if it satisfies all the necessary requirements. If acceptable this scheduler shall change the validated request to a confirmed booking. If it is subject to the outcome of another booking, the booking shall reflect that it is linked to another confirmed booking. If the request cannot be accommodated, it shall be marked as "refused", with a reason and/or an alternative suggestion for a time being given
- 17.3.7. When it is time for the confirmed booking to be executed (the outage becoming effective), the status shall be changed to "Taken" by the *System and Market Operator* shift controller if sanctioning (i.e. not refusing) the outage. While an outage is in progress the responsible *Participants* may report the actual state of the progress to the *System and Market Operator* shift controller, who shall enter this information into the system. This allows for the progress of the outage to be monitored by those concerned.
- 17.3.8. When the outage has been completed it shall be the responsibility of the *System and Market Operator* shift controller receiving the information, to change the status of the outage to "completed".
- 17.3.9. When an outage is cancelled or refused it is the responsibility of the person cancelling or refusing the outage to furnish the reasons for cancellation or refusal. The person receiving the cancellation or refusal shall then enter this information into the system when changing the status to "cancelled".
- 17.3.10. This shall also apply to outages that are postponed.

17.4. RISK-RELATED OUTAGES

- 17.4.1. All Risk-related Outages shall be scheduled a minimum of 14 days in advance with an executable contingency plan in place. The compilation of the contingency plan is the responsibility of System and Market Operator.
- 17.4.2. These contingency plans are, in some cases, of a permanent nature and will be in force every time the same system conditions apply. These contingency plans will therefore only have to be prepared once and will come into force again (with minimal changes if needed) when the same outage is scheduled.
- 17.4.3. Contingency plans shall consist of five parts:
- a) Security linking prior to the outage, to ensure minimal risk to Users.
 - b) Returning the plant that is on outage back to service as soon as possible.
 - c) Restoring supply to Users by utilising by-pass schemes.
 - d) Load shedding if necessary (load profiles shall be made available by the User).
 - e) List of contact persons.
- 17.4.4. Responsibilities during the compilation of contingency plans are as follows:
- a) The System and Market Operator shall be responsible for identifying Risk-related Outages;
 - b) The System and Market Operator and User control centres shall be responsible for the Security-linking instructions in the said contingency plan;

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- c) It shall be the responsibility of the Transmission Licensee to supply the information relating to returning the plant to service;
 - d) The Transmission Licensee shall develop by-pass schemes with assistance from the System and Market Operator and the User control centre;
 - e) The System and Market Operator and User Control Centres shall be responsible for identification of the load at risk and load shedding in the said contingency plan;
- 17.4.5. If the contingency plan indicates that load shedding must take place it shall include the following details:
- a) The total amount of load to be shed in relation to the load profile.
 - b) The point at which Users' load must be shed for optimal results.
- 17.4.6. The relevant *control centres* shall confirm that it is possible to execute the contingency plan successfully.
- 17.4.7. To ensure that the *control centre* is in possession and aware of the contingency plan the outage scheduler shall contact the *control centre* a *day* prior to the outage.
- 17.4.8. Negotiation of all *Risk-related Outages* shall take place with affected *Users* a minimum of 28 days prior to the outage being executed, unless otherwise agreed. Where a request comes from a *generator* with a requirement for 28 days' notice, this time period shall be respected by the parties. *Customers* shall be involved in the planning phase of projects and outages that will affect them.
- 17.4.9. These conditions shall also apply to all outages affecting international *customers*.
- 17.4.10. The Transmission Licensee shall give Distribution Licensees and end-users at least 14 days' notice of Planned Interruptions.

17.5. MAINTENANCE PLANNING BETWEEN THE TRANSMISSION LICENSEE AND GENERATORS

- 17.5.1. Over and above the requirements mentioned above, all *generators* shall provide the *System and Market Operator* with the following documents in the pro-forma format specified in the Information Exchange Code, section 20, to enable it to execute its short-term power system reliability responsibility:
- a) A 52-weeks-ahead outage plan per Power Station, showing Planned Outage and return dates and other known generation constraints, updated weekly by 15:00 every Monday (or first working day of the week);
 - b) An annual maintenance / outage plan per Power Station, looking five years ahead, showing the same information as above and issued by 30th June of each year;
 - c) A monthly variance report, explaining the differences between the above two reports.
- 17.5.2. Each *generator* shall invite the *Transmission Licensee* to provide inputs into the compiling of the five-year-ahead annual maintenance plans mentioned above, on the basis of ensuring system reliability, and shall not unreasonably reject such inputs. Any such rejection shall be substantiated by providing the *Transmission Licensee* with documentary proof of the reasons.
- 17.5.3. Plant versus system risks shall be carefully weighed up by the affected *Participants* under all circumstances. Joint risk assessments shall be undertaken and joint contingency plans under these outage conditions shall be prepared by the affected *Participants*.
- 17.5.4. Each *generator* shall ensure the absolute minimum deviation from its annual outage plan. Each deviation shall be negotiated with the *System and Market Operator*.
- 17.5.5. The *System and Market Operator* shall coordinate network outages affecting *unit* output with related *unit* outages to the maximum possible extent.

17.5.6. The objectives to be used by the *System and Market Operator* in this maintenance coordination are firstly maintaining adequate reserve levels at all times, secondly ensuring reliability where *TS* constraints exist, and thirdly maintaining acceptable and consistent real-time technical risk levels.

17.6. REFUSAL/CANCELLATION OF OUTAGES

No *Participant* may unreasonably refuse or cancel a confirmed outage, or the risks associated with that refusal/cancellation shall be transferred to that *Participant*. In the case of the *System and Market Operator* cancelling the request owing to system conditions, the parties shall bear own costs arising from such cancellation.

17.7. COMMISSIONING

17.7.1. The *System and Market Operator* shall verify commissioning/maintenance programmes concerning operations at major *substations* as far as is needed to ensure adequate co-ordination and reliability of the *IPS*.

17.7.2. All aspects of commissioning, by *Users*, of new equipment associated with the *Transmission* connection, or re-commissioning of such existing equipment, shall be agreed with the *System and Market Operator* in writing before such commissioning starts.

17.7.3. The said aspects shall include, but not be limited to the following:

- a) Commissioning procedures and programmes
- b) Documents and drawings required
- c) Proof of compliance with standards
- d) Documentary proof of the completion of all required tests
- e) SCADA information to be available and tested before commissioning
- f) Site responsibilities and authorities, etc.

17.7.4. A minimum notice period of one *Month* shall apply from the date of receipt of the request for all commissioning or re-commissioning.

17.7.5. When commissioning equipment at the point of connection, the *Transmission Licensee* shall liaise with the affected *Users* on all aspects that could potentially affect the *Users'* operations. The *Transmission Licensee* and *Users* shall perform all commissioning tests required in order to confirm that the *Transmission Licensee* and the *Users'* plant and equipment meets all the requirements of the *Grid Code* that must be met before going on-line.

17.7.6. Where commissioning is likely to involve a requirement for dispatch and/or operating for test purposes, the *User* shall, as soon as possible, notify the *System and Market Operator* of this requirement, including reasonable details as to the duration and type of testing required.

PART 5: METERING CODE

SECTION 18: METERING REQUIREMENTS

18.1. OBJECTIVE

- 18.1.1. This Section provides metering requirements for Single Buyer, Transmission Licensee and all current and future Market Participants, as required by the Market Rules. It specifies Metering standards to be adhered to and clarifies levels of responsibility.
- 18.1.2. The Metering specification shall be used as the Metering requirements for the Grid Code and the Market Rules and it will conform the Commercial Metering System, as defined in the Market Rules.
- 18.1.3. This Part sets out provisions relating to Main Metering Installations and check Metering Installations used for the measurement of active and reactive energy.
- 18.1.4. This Section shall apply to all Market Participants in respect of any Metering point at the boundary of Transmission system (TS) and any Metering Point at the boundary between a Distribution System (DS) and any other Market Participant.

18.2. TYPE OF CONNECTION POINTS

- 18.2.1. A Commercial Metering System will be installed to measure active energy, reactive energy and maximum demand at each Point of connection on the TS or DS, where an interface exists between a Market Participant and the TL or two or more Market Participants. This will comprise both Import and Export metering at all Interconnections.
- 18.2.2. The Commercial Metering System comprises both the Main Metering Equipment and the Check Metering Equipment, when the latter is required.
- 18.2.3. For the purposes of the Market Rules, the Point of connections shall be classified as follows:
- a) Type 1: Between a Generator with a capacity equal to or higher than [10 MW] and the TS or the DS, as it corresponds; or between the TS and the DS; or between the TS and a Bulk Supply Consumer with a connection capacity equal to or higher than [5 MW];
 - b) Type 2: International Interconnections;
 - c) Type 3: Between two DS of different licensees; and
 - d) Type 4: All other Connection Points.
- 18.2.4. Main and Check Metering Equipment shall be installed in all Connection Points of Type 1, 2 or 3. In Type 4 Connection Points only Main Metering Equipment shall be installed, although an installation of a Check Metering Equipment is advisable.
- 18.2.5. Check Metering can be obtained through:
- a) Redundant Metering, when the Check Metering Equipment is installed at the same Point of connection where the Main Meter is installed; or
 - b) Verification Metering, when Metering Equipment or set of Metering Equipment is installed at different locations than the Main Meter and whose measurements permits the verification of the Main Meter measurement through simple calculations that eliminate the effect of the network element that could exist between them.

18.3. LOCATION OF MAIN AND CHECK METERING EQUIPMENT

18.3.1. As a general rule, both Main Metering Equipment and Check Metering Equipment will be located as close as practicable to the Point of connection. Where there is a material difference in location, an adjustment for losses between the location of the Metering Equipment and the Point of connection will be calculated by the SMO and agreed to by the involved Market Participant. Such loss adjustments may include transformer and line loss compensation resulting from the distance of the Metering Equipment to the physical location of the Point of connection.

- a) At Type 1 Connection Points, as far as practicable, the Main Metering Equipment shall be located at the actual Point of connection. Check Metering shall be obtained preferably through a Redundant Meter, located at the same point as the Main Metering Equipment. In cases this option seems non practicable then Verification Metering shall be used, with Meters located at the nearest practicable points.
- b) At Type 2 Connection Points, the Main Metering Equipment shall be located at an agreed Point of connection with any neighbouring country. Check Metering shall be obtained either through a Redundant Meter located at the same point as the Main Metering Equipment. Alternatively, check metering shall be obtained through Verification Metering, with Meters located in the other extreme of the interconnection line (in the neighbouring country) if the SMO agrees with this possibility and the Interconnection Trading Agreements allow adequate interchange of the information required in a timely manner.
- c) At Type 3 Connection Points, the Metering Equipment shall be located at both ends of the line between substations of different licensees. Each licensee shall consider the Metering Equipment at its own substation as Main Metering and Verification Metering can be obtained through the measurements in the other extreme.
- d) At Type 4 Connection Points the Main Metering Equipment shall be located as close as possible to the actual Point of connection.

18.4. CHARACTERISTICS OF THE METERING EQUIPMENT

18.4.1. Meters and instrument transformers for Commercial Metering shall comply with Malawi Standards on Metering specifications and the latest applicable international and local standards, including, but are not limited to, the following:

- a) IEC 60145 Var-hour (reactive energy) meters
- b) IEC 60521 Class 0.5, 1 and 2 alternating-current watt-hour meters
- c) IEC 60687 Alternating current static watt-hour meters for active energy (classes 0.2 S and 0.5 S).
- d) IEC 61036 Alternating current static watt-hour meters for active energy (classes 1 & 2).02
- e) IEC 61107 Data exchange for meter reading, tariff and load control - direct local data exchange.
- f) IEC 61354 Electricity meters – marking of auxiliary terminals for tariff devices
- g) IEC 61361 Electricity metering – local and remote data exchange.
- h) IEC 62053-61 Electricity metering equipment (ac) – particular requirements – Part 61: power consumption and voltage requirements.
- i) IEC 62056-31 Electricity metering – Data exchange for meter reading, tariff and load control – Part 31: Use of local area networks on twisted pair with carrier signalling.
- j) IEC 62056-41 Electricity metering – Data exchange for meter reading, tariff and load control – Part 41: Data exchange using wide area networks: Public Switched Telephone Network with LINK+ protocol.
- k) IEC 62056-51 Electricity metering – Data exchange for meter reading, tariff and load control – Part 51: Application layer protocol.
- l) IEC 60044-1 Instrument transformer – Part 1: Current transformer.
- m) IEC 60044-2 Instrument transformer – Part 2: Inductive voltage transformer.

- n) IEC 60044-3 Instrument transformer – Part 3: Combined transformers
- o) IEC 60186 Voltage transformers

18.4.2. The Commercial Metering System shall read and record energy and power (Active and Reactive) delivered to or received at each Point of connection, with an appropriate degree of accuracy specified in applicable IEC Standards, but not less than +/- 0.2%.

18.4.3. The Commercial Metering Equipment shall have the following characteristics:

- a) Three elements four-wire configuration;
- b) Capable of recording active and reactive power and energy and maximum Load Demand for the entire billing period on internal or separate Data Registers. In any case, all Meters shall have a display showing the accumulated values of the measured quantities. The meter-billing period may be programmable and capable of being programmed to automatically store the accumulated value and reset the counter for the next billing period;
- c) Registers of active energy shall be done in all the ways the energy could flow. This may be achieved by using one or more metering equipment as it is convenient. Registers of reactive energy shall be done in all the four quadrants reactive energy could flow. This may be achieved by using one or more Metering equipment as it is convenient;
- d) In cases separate Data Registers are used, each Data Register may store information from one or more Metering Equipment, provided that Redundant or Verification Meters shall have separate Data Registers from the Main Meters;
- e) Data Registers shall have adequate capacity to store at least one year with intervals programmable from 5 minutes to 30 minutes in non-volatile memories;
- f) Meters or Data Registers may have capability for remote meter reading by telemetering or by SCADA and locally retrievable. Communication ports should be provided with optical and serial data communication with industry standard protocol support;
- g) The SMO shall define the communication protocol to be used, which shall be unique and of standard type in order to reduce the costs that shall be borne by the Market Participants. The selected communication protocol shall be approved by MERA and communicated to the involved Market Participants at least six (6) month before remote interrogation will start;
- h) The Meter should have self-diagnostic capability and include an alarm to indicate failure and/or tampering;
- i) Meter shall be visible and accessible, enclosed in a cabinet or otherwise installed in a manner which shall conform to the manufacturer's stated environmental conditions. The installation shall provide protection from moisture and dust ingress and from physical damage, including vibration. In addition, the cabinet or meter must be sealed to prevent unauthorised access;
- j) The meters shall be equipped with facility for recording and reporting quality of service and supply.

18.4.4. Measuring Transformers shall have the following characteristics:

- a) Measuring transformers shall be referred to the applicable IEC metering standards;
- b) Main and Check Metering shall operate from separate current transformers (CT) and voltage transformers (VT) windings;
- c) As a general rule, CT and VT windings and cables connecting such windings to Main or Check Metering shall be dedicated for such purposes and such cables and connections shall be securely sealed;
- d) Eventually, CT and VT windings and cables connecting such windings to Check Meters may be used for other purposes provided the overall accuracy requirements are met and evidence of the value of the additional burden is available for inspection by the SMO.

18.4.5. The accuracy requirements for the Commercial Metering are defined by type of Point of connection as indicated in the table below:

Equipment Type	Equipment Accuracy Class		
	For Connections		
	Type 1	Type2	Type 3 and 4
Current Transformers	0.2S	0.2S	0.5
Voltage Transformers	0.2	0.2	1
Active Energy Meters	0.2S	0.2S	1
Reactive Energy Meters	2	2	2

SECTION 19: METERING RESPONSIBILITIES

19.1. OBJECTIVE

19.1.1. This Section sets out provisions relating to:

- a) The collection of metering data;
- b) The provision, installation and maintenance of equipment;
- c) Testing procedures.

Other aspects related with the Metering process are established in the Market Rules.

19.2. RESPONSIBILITY FOR METERING INSTALLATIONS

19.2.1. The Market Participants shall be responsible for ensuring that all points identified as Connection Points in accordance with the principles of the previous sections have a Commercial Metering System.

19.2.2. The System and Market Operator shall be responsible for managing and collecting Metering information.

19.2.3. Market Participants connected to or wanting to connect to the Transmission System or other Market Participants shall provide the System and Market Operator with all information deemed necessary to enable performance of its Metering duties.

19.2.4. In the event of a Commercial Metering System being positioned between two Distribution Licensees, the following shall apply:

- a) Each Distribution Licensee shall be responsible for installing and maintaining own Metering equipment in accordance with the requirements of this section. All costs related to this metering installation shall be borne by the respective owners;
- b) The Distribution Licensees shall ensure that the System and Market Operator is given remote/electronic access to the Metering Installation. Should access to the Metering Installation compromise the Security of the installation, then Metering data shall be supplied to the System and Market Operator on a daily basis in an appropriate format;
- c) The meter data retrieval process shall be a secure process whereby meters or recorders are directly interrogated to retrieve billing information from their memories.

19.3. DATA VALIDATION

19.3.1. *Data* validation shall be carried out by the System and Market Operator in accordance with IEC Standards and the Market Rules

19.3.2. In the event of:

- a) Electronic access to the meters not being possible;
- b) An emergency bypass or other scheme having no Metering system; or
- c) Metering data not being available;

The System and Market Operator may resort to the following:

- (i) Manual meter data downloading (performed with the assistance of the Transmission Licensee);
- (ii) Estimation or substitution subject to mutual agreement between the affected parties;
- (iii) Profiling; and
- (iv) Reading of the meter at scheduled intervals.

19.3.3. In the event of an estimation having to be made, the following shall apply:

- a) A monthly report shall be produced by the Single Buyer for all estimations made;
- b) No estimation shall be made on three or more consecutive time slots, and if such estimation had to be made, the Single Buyer shall ensure that the meters are downloaded for the billing cycle.

19.3.4. Not more than ten (10) slots may be estimated per meter point per *Month*. If such estimation has to be made, the *SMO* shall ensure that the meters are downloaded for the billing cycle.

19.4. METER VERIFICATION

19.4.1. In addition to the IEC verification requirements, meter readings shall be compared with the *Metering data* base at least once a year.

19.4.2. Metering Installations shall be audited in accordance with IEC Standards or equivalent.

19.4.3. Commissioning of the Metering Installation and Metering data supporting systems shall take place in accordance with the requirements of Malawi Standards.

19.5. TESTING OF METERING INSTALLATIONS

19.5.1. Commissioning, auditing and testing of Metering Installations shall be done in accordance with IEC Standard specification.

19.5.2. Any Participant may request MERA or an agency acting on its behalf that testing of a Metering Installation be performed. Such a request shall not be unreasonably refused. The costs of such test shall be for the account of the requesting Participant if the meter is found to be accurate and to the account of the Single Buyer if the meter is found to be inaccurate.

PART 6: INFORMATION EXCHANGE CODE

SECTION 20: INFORMATION EXCHANGE

20.1. INTRODUCTION

- 20.1.1. The Information Exchange Code defines the obligations of parties with regard to the provision of Information for the implementation of the Grid Code. The Information requirements as defined for the service-providers, Malawi Energy Regulatory Authority (MERA) and Users are necessary to ensure the non-discriminatory access to the Transmission System (TS) and the safe, reliable provision of Transmission services.
- 20.1.2. The Information requirements are divided into planning Information, operational Information and post-dispatch Information.
- 20.1.3. Information criteria specified in this Part is supplementary to the other Parts within this Grid Code.

20.2. CONFIDENTIALITY OF INFORMATION

- 20.2.1. Information exchanged between parties governed by this Code shall be confidential, unless otherwise stated or where Information is defined as being in the public domain.
- 20.2.2. Confidential Information shall not be transferred to a third Party without the written consent of the Information Owner. Parties shall observe the proprietary rights of third parties for the purposes of this code.
- 20.2.3. Parties receiving Information shall use the Information only for the purpose for which it was supplied.
- 20.2.4. The Information Owner may request the receiver of Information to enter into a confidentiality agreement before confidential Information is provided. A proforma agreement is included in Appendix 1.
- 20.2.5. The parties shall take all reasonable measures to control unauthorised access to Information and to ensure secure Information exchange. Parties shall report any violation of Information Security to the Information Owner.

20.3. INFORMATION EXCHANGE INTERFACE

- 20.3.1. The *parties* shall identify the following for each type of *Information* exchange:
- a) The name and contact details of the person(s) designated by the Information;
 - b) Owner to be responsible for provision of the Information;
 - c) The names and contact details of and the parties represented by persons requesting the Information; and
 - d) The purpose for which the Information is required.
- 20.3.2. The parties shall agree on appropriate confirmation procedures for the transfer of Information. Access to Information shall be provided by the relevant parties with reasonable motivation and notice.

20.4. SYSTEM PLANNING INFORMATION

- 20.4.1. Users shall provide such Information as the Transmission Licensee, the System and Market Operator or the Single Buyer may request on a regular basis for purposes of the planning and development of the TS. Users shall submit the Information to the Transmission Licensee, the System and Market Operator or the Single Buyer, as it corresponds, without unreasonable delay. Such Information may be required so that the Single Buyer and the Transmission Licensee can plan and develop the TS, monitor current and future power system adequacy and performance or fulfil its statutory or regulatory obligations.
- 20.4.2. Users shall submit to the Transmission Licensee, the System and Market Operator or the Single Buyer the Information listed in Appendix 2 (for distributors or Bulk Supply Customers) or Appendix 3 (for generators).
- 20.4.3. The Transmission Licensee, the System and Market Operator and the Single Buyer shall keep updated technical databases of the IPS for purposes of modelling and studying the behaviour of the IPS.
- 20.4.4. The Transmission Licensee shall provide Users or potential Users, upon any reasonable request, with any relevant Information that they require to plan and design their own networks/installations properly or comply with their other obligations in terms of the Grid Code.
- 20.4.5. The *Transmission Licensee* shall make available all the relevant *Information* related to network planning as described in the Planning Code.
- 20.4.6. *Customers* shall, upon request to upgrade an existing connection or when applying for a new connection, provide the *Transmission Licensee* with *Information* relating to the following:

Commissioning	Projected or target commissioning test date
Operating	Target operational or on-line date
Reliability connection requested	of Number of connecting circuits e.g. one or two feeders, or firm/non-firm (subject to Network and requirements)
Location map.	Upgrades: Name of existing <i>Point of Supply</i> to be upgraded and supply voltage. New connections: Provide a 1:50 000 or other agreed scale location map, with the location of the facility clearly marked. In addition, please specify the co-ordinates of the <i>Point of Connection</i> .
Site plan	Provide a plan of the site (1:200 or 1:500) of the proposed facility, with the proposed <i>Point of Supply</i> , and where applicable, the <i>Transmission</i> line route from the facility boundary to the <i>Point of Supply</i> , clearly marked.
Electrical single-line diagram	Provide an electrical single-line diagram of the Customer intake Substation.

- 20.4.7. The Transmission Licensee may estimate any system planning Information not provided by the User as specified in Appendix 2 or 3. This estimation, however, does not limit the responsibility of the User in relation with providing proper and accurate information about the equipment connected to the TS. The Transmission Licensee shall indicate to the User any data items that have been estimated.
- 20.4.8. Generators shall submit to the Transmission Licensee all the Information detailed in Appendix 4 with regard to each Generating Unit at each Power Station.

20.5. OPERATIONAL INFORMATION

20.5.1. Pre-commissioning studies

- a) Users shall meet all system planning Information requirements before the commissioning test date. (This will include confirming any estimated values assumed for planning purposes or, where practical, replacing them with validated actual values and with updated estimates for the future.)
- b) The System and Market Operator shall perform pre-commissioning studies prior to sanctioning the final connection of new or modified plant to the TS, using data for exciter, turbine governor, and HVDC systems and FACTS device parameters and settings supplied by Users, to verify that all control systems are correctly tuned and planning criteria have been satisfied.
- c) The System and Market Operator may request adjustments prior to commissioning should tuning adjustments be found to be necessary. All Participants are responsible for ensuring that exciter, turbine governor, FACTS and HVDC control system settings are as finally recorded by the System and Market Operator prior to commissioning.

20.5.2. Commissioning and notification

- a) Users seeking connection shall give the System and Market Operator reasonable advance notice, as defined in the System Operation Code, of the time at which the commissioning tests will be carried out. The System and Market Operator and the Participant shall agree on the timeous provision of operational data items as per Appendix 5.
- b) Users shall jointly verify all measurements and/or indications for functionality and accuracy once every three (3) years, so as to achieve overall accuracy of operational measurements within the limits agreed. Records of commissioning shall be maintained for reference by the System and Market Operator for the operational life of the plant and shall be made available, within 7 days, to authorised Users upon notification of such a request.
- c) A User connected to the TS shall ensure that measurement equipment complies with the following accuracy classes:

Measurement Equipment	Accuracy Class
Current transformer (CT)	0,2%
Voltage transformer (VT)	0,2%
Transducer	0,2%
Analogue to digital conversion, i.e. RTU	0,01%

20.5.3. General information acquisition requirements

- a) Measurements and indications to be supplied by Users and the Transmission Licensee to the System and Market Operator shall include but not limited to the standards defined in Appendix 5. Where required signals become unavailable or do not comply with applicable standards for reasons within the control of the provider of the Information, such Participant shall report and restore or correct the signals and/or indications as soon as possible.
- b) All measurements and indications to be supplied by Participants to the System and Market Operator shall be presented in such a form as may be prescribed by the System and Market Operator. The System and Market Operator shall notify the Participant, where it, acting reasonably, determines that because of a modification to the TS or otherwise, additional measurements and/or indications in relation to a Participant's plant and equipment are needed to meet a TS requirement. The costs related to such modifications shall be for the account of the providing Participant.
- c) On receipt of such notification from the System and Market Operator, the Participant shall promptly ensure that such measurements and/or indications are made available at the RTU; and

-
- d) The data formats to be used and the fields of Information to be supplied to the System and Market Operator by the various Participants are defined in Appendix 5.

20.5.4. **Inter control centre communication.** All *customer control centres* shall provide the *System and Market Operator* with network *Information* that is considered reasonable for the *Security* and integrity of the *TS* on request. The *System and Market Operator* shall communicate network *Information* as requested to the *customer control centres*, as required for safe and reliable operation. The *Information* exchange between *control centres* shall be electronic and/or paper-based within the time-frame agreed upon.

20.5.5. **Communication facilities requirements.** The minimum communication facilities for voice and *data* that are to be installed and maintained between the *System and Market Operator* and *Participants* shall comply with the applicable *IEC* standards for *SCADA* and communications equipment and shall meet such standards as may be set by the *System and Market Operator*, acting reasonably, in advance of design.

a) Telecontrol.

a.1) The Information exchange shall support data acquisition from remote terminal units (RTU). The System and Market Operator shall be able to monitor the state of the Independent Power Supply via telemetry from the RTU connected to the Participants' plant.

a.2) The signals and indications required by the System and Market Operator are defined in Appendix 5, together with such other Information as the System and Market Operator may from time to time reasonably require by notice to the Participant.

a.3) Participants shall interface via the standard digital interfaces, as specified by the System and Market Operator. Interface cabinets shall be installed in the Participants' plant and equipment room if required. The provision and maintenance of the wiring and signalling from the Participants' plant and equipment to the interface cable shall be the responsibility of the Participant.

a.4) The capability for the System and Market Operator to deactivate and reactivate the scanning of a given RTU shall be provided by the Participants, as shall the capability of monitoring the availability of all RTU centrally.

a.5) Participants shall comply with such telecontrol requirements as may be applicable to the primary control centre and, as reasonably required, to the emergency control centre of the System and Market Operator.

b) Telephone / Facsimile

b.1) Each User shall be responsible for the provision and maintenance of no less than one telephone and one facsimile unit that shall be reserved for operational purposes only and shall be continuously attended to and answered without undue delay.

b.2) The System and Market Operator shall use a voice recorder for historical recording of all operational voice communication with Participants. These records shall be available for at least three (3) Months. The System and Market Operator shall make the voice records of an identified incident in dispute available within a reasonable time period after such a request from a Participant and/or MERA.

c) Electronic mail

c.1) The Participants shall provide the System and Market Operator with the electronic mailing address of the contact person as defined in this Information Exchange Code and vice versa. The service-provider shall be selected to meet the real-time operational requirements of the System and Market Operator.

20.5.6. Infrastructure at points of supply

a) Access and Security

a.1) The System and Market Operator shall agree with Participants the procedures governing Security and access to the Participants' SCADA, computer and communications equipment. The procedures shall allow for adequate access to the equipment and Information by the System and Market Operator or its nominated representative for purposes of maintenance, repair, testing and the taking of readings.

- a.2) Each Participant shall designate a person with delegated authority to perform the duties of Information Owner in respect of the granting of access to Information covered in this code to third parties and shall disclose that person's name and contact details to MERA. A Party may, at its sole discretion, designate more than one person to perform these duties.
- b) **Time standards.** All Information exchange shall be global positioning system satellite time signal referenced. The System and Market Operator shall ensure broadcasting of the standard time to relevant telecommunications devices in order to maintain time coherence.
- c) **Integrity of installation.** The Participant shall be responsible for optimising the reliability and Security of the facilities to comply with the System and Market Operator equipment and OEM minimum requirements. This includes the provision, at no charge to the System and Market Operator, of an uninterruptible power supply with an eight-hour standby capacity.

20.5.7. Data storage and archiving

- a) The obligation for data storage and archiving shall lie with the Information Owner.
- b) The systems that store the data and/or Information to be used by the parties shall be of their own choice and for their own cost.
- c) All the systems must be able to be audited by the authorised parties. The systems must provide for clear and accessible audit trails on all relevant operational transactions. All requests that require an audit on a system shall be undertaken with reasonable notice to the parties.
- d) The Information Owner shall keep all Information for a period of at least five (5) years (unless otherwise specified in the Grid Code) commencing from the date the Information was created.
- e) The parties shall ensure reasonable Security against unauthorised access and use and the loss of Information (i.e. have a backup strategy) for the systems that contain the information.

20.6. POST-DISPATCH INFORMATION

20.6.1. File transfers

- a) The format of the files and the file transfer media used for data transfer shall be decided by the System and Market Operator.
- b) The parties shall keep the agreed number of files for backup purposes so as to enable the recovery of information in the case of communication failures.

20.7. PERFORMANCE DATA

20.7.1. Generator performance data

- a) Generators shall provide the System and Market Operator monthly, official performance indicators in relation to each Generating Unit at each Power Station in respect of availability, reliability, etc. as detailed in Appendix 8.

20.7.2. Distributor and Bulk Supply Customers performance

- a) The performance measurement of all distributors and end-user shall be in accordance with the quality-of-supply requirements as defined in this Grid Code.
- b) Periodic testing of under-frequency load shedding relays shall be reported in the following format:

Distributor:
Date:

Substation:				
Fed from Transmission Substation (directly or Indirectly)				
	Activating Frequency		Timer Setting	
	Required	As Tested	Required	As Tested
Stage 1				
Stage 2				
Stage 3				
Stage 4				
	Feeders Selected (Required)		Feeders Selected (As Tested)	
Stage 1				
Stage 2				
Stage 3				
Stage 4				

20.7.3. Transmission System performance

- a) The Transmission System Operator shall make the following performance indicators for the TS available quarterly to MERA, participant and the Single Buyer:

Indicator	Month	Year to date	12MMI	Unit
System Minutes lost				Minutes
No. of interruptions				
No. of Voltage Variations outside Statutory Limits				
Mandatory under frequency load				
Customer voluntary load shedding				
TS losses				%

20.7.4. System performance information

- a) The following IPS operational information shall be made available by System and Market Operator:
- a.1) Daily:
- The half hourly actual demands of the previous *day* (MW)

-
- The reserve amounts over the morning and evening peaks of the previous *day* (MW)

a.2) Annually:

- Annual peak (MW), date and hour
- Annual minimum (MW), date and hour

SECTION 21: APPENDICES

21.1. APPENDIX 1: INFORMATION CONFIDENTIALITY

SAMPLE CONFIDENTIALITY AGREEMENT FOR INFORMATION TRANSFER TO THIRD PARTIES

CONFIDENTIALITY AGREEMENT BETWEEN.....(HEREINAFTER REFERRED TO AS THE *INFORMATION OWNER*) AND..... (HEREINAFTER REFERRED TO AS THE RECIPIENT)IN RESPECT OF INFORMATION SUPPLIED TO PERFORM THE FOLLOWING WORK:.....(HEREINAFTER REFERRED TO AS THE WORK) ON BEHALF OF..... (HEREINAFTER REFERRED TO AS THE CLIENT).

- 1) The Recipient agrees to treat all information (hereinafter referred to as the *Information*) received from the *Information Owner*, whether in hard copy or electronic format, as strictly confidential.
- 2) The Recipient agrees to disclose the *Information* only to persons who are in his permanent employ, and who require access to the *Information* to perform their duties in respect of the Work on behalf of the Client.
- 3) Persons other than those described in Clause 2 above, including but not restricted to temporary employees, subcontractors, and sub-consultants, shall enter into separate Confidentiality Agreements with the *Information Owner* prior to receiving the *Information*.
- 4) The Recipient undertakes to use the *Information* only to perform the Work on behalf of the Client, and for no other purpose whatsoever.
- 5) On completion of the Work, the Recipient shall at his expense return to the *Information Owner* all hard copy material and computer disks containing the *Information* supplied to him by the *Information Owner*. The Recipient shall furthermore ensure that all duplicate copies of the *Information* in his or his employees' possession (electronic as well as hard copy format) are destroyed.
- 6) The Recipient shall take all reasonable measures to protect the *Security* and integrity of the *Information*.
- 7) If requested to do so by the *Information Owner*, the Recipient shall forthwith at his expense return to the *Information Owner* all hard copy material and computer disks containing the *Information* supplied to him by the *Information Owner*. The Recipient shall furthermore ensure that all duplicate copies of the *Information* in his or his employees' possession (electronic as well as hard copy format) are destroyed.
- 8) The Recipient shall report any leak of the *Information*, howsoever caused, to the *Information Owner* as soon as practicable after he becomes aware of the leak, and shall provide to the *Information Owner* with all reasonable assistance to ensure its recovery or destruction (as deemed appropriate by the *Information Owner*).

Signed at on this the day of..... by (full name)in his/her capacity as.....On behalf of....., the *Information Owner*.....

Signed at on this the..... day of..... by

(full name)in his/her capacity as.....on behalf of....., the Recipient.....

21.2. APPENDIX 2: DISTRIBUTOR AND BULK SUPPLY CUSTOMER DATA

Unless otherwise indicated, the following information shall be supplied to the *Transmission System*, prior to connection and then updated as and when changes occur.

21.2.1. Demand data

Connection capacity	Connection capacity required (MW)
Measured and forecast data (annually)	<p>For each Point of connection, the information required is as follows:</p> <ul style="list-style-type: none"> • A 5-year demand forecast. (See Appendix 9). • A description setting out the basis for the forecast. • The season of peak demand • Quantification of the estimated impact of embedded generation. (See Appendix 9) • A 10-year demand estimate
User network data	<ul style="list-style-type: none"> • Electrical single-line diagram of user network to a level of detail to be agreed with the service- providers, including the electrical characteristics of circuits and equipment (R, X, B, R0, X0, B0, continuous and probabilistic ratings). • Contribution from User network to a three-phase short circuit at Point of Connection. • Connection details of all User transformers, shunt capacitors, shunt reactorsetc. connected to the secondary voltage levels of the User connected the TS. (the requirement here is for data pertaining to the network connecting shunt capacitors, harmonic filters, reactors, SVCs, etc. to the Connection Point for purposes of conducting harmonic resonance studies.) • Electrical characteristics of all circuits and equipment at a voltage lower than secondary voltage levels of the User connected the TS that may form a closed tie between two connection points on the TS.
Standby supply data (annually)	<p>The following information is required for each distributor and end-use User that can take supply from more than one supply point:</p> <ul style="list-style-type: none"> • Source of standby supply (alternative supply point(s)) • Standby capacity required (MW)
General information	<p>For each new connection from a distributor or Bulk Supply Customer, the following information is required:</p> <ul style="list-style-type: none"> • Number and type of switch bays required • Load build-up curve (in the case of new end-user plant)

	<ul style="list-style-type: none"> • Load type (e.g. ARC furnaces, rectifiers, rolling mills, residential, commercial, etc.) • Annual load factor • Power factor (including details of harmonic filters and power factor correction capacitors) <p>Special requirements (e.g. quality of supply)</p> <p>Other information reasonably required by the service- providers to provide the customer with an appropriate supply (e.g. pollution emission levels for insulation design)</p>
Disturbing loads	<p>Description of any load on the power system that could adversely affect the System and Market target conditions for power quality and the variation in the power quality that can be expected at the point connected to the TS. (The areas of concern here are, firstly, motors with starting currents referred back to the nominal voltage at the Connection Point exceeding</p> <p>5% of the fault level at the Connection Point and secondly, ARC furnaces likely to produce flicker levels at the Connection Point in excess of the limits specified in By-Laws. The size limit for ARC furnaces is subject to local conditions in respect of fault level at the Connection Point and background flicker produced by other ARC furnaces.)</p>

21.2.2. Transmission System connected transformer data

	Symbol	Units
Number of Windings		
Vector Group		
Rated Current of Winding		A
Transformer rating		MVA _{trans}
Transformer tertiary rating		MVA
Transformer nominal Secondary (LV) voltage		kV
Transformer nominal tertiary voltage		kV
Transformer nominal Primary (HV) voltage		kV
Tapped winding		HV/MV/LV/none Delete what is not applicable
Transformer ratio at transformer taps		
Transformer Impedance (resistance R and reactance X) at all taps	R+jX	% on rating MVA _{trans}

For the three –winding transformers, where there are external connections to all three windings, the impedance (resistance R and Reactance X) between each pair of windings is required , measured with the third set of terminals open - circuit	Z_{HVMV} , Z_{HVLV} , & Z_{MVLV}	% on rating MVA_{trans} % on rating MVA_{trans} % on rating MVA_{trans}
Transformer zero sequence impedances at nominal tap		
Zero phase sequence impedance measured between the HV terminals (shorted) and the neutral terminal ,with the LV terminals open- circuit	Z^0_{HV}	ohm
Zero phase sequence impedance measured between the HV terminals (shorted) and the neutral terminal ,with the LV terminals short- circuited to the neutral	Z^0_{HL}	ohm
Zero phase sequence impedance measured between the LV terminals (shorted) and the neutral terminal ,with the HV terminals open circuit	Z^0_{LV}	ohm
Zero phase sequence impedance measured between the LV terminals (shorted) and the neutral terminal ,with the HV terminals short- circuited to the neutral	Z^0_{LH}	ohm
Zero phase sequence impedance measured between the HV terminals (shorted) and the LV terminals (shorted) ,with the delta winding closed	Z^0_L	ohm
Earthing arrangement, including LV neutral earthing resistance and reactance core construction (number of limbs, shell or core type)		graph
Open circuit characteristics		

Transformer test certificates, from which actual technical detail can be extracted as required, are to be supplied on request.

21.2.3. Shunt capacitor or reactor data requirements

- a) For each shunt capacitor or reactor or power factor correction equipment or harmonic filters with a rating in excess of 1 MVAR connected to or capable of being connected to a User network, the User shall inform the Transmission Licensee with the specific shunt capacitor or reactor data as well as network details necessary to perform primarily harmonic resonance studies. The User shall inform the Transmission Licensee of his intention to extend or modify this equipment.
- b) If any Participant finds that a capacitor bank of 1MVAR or less is likely to cause harmonic resonance problems on the TS, he shall inform the Transmission Licensee. The 1MVAR minimum size limit shall thereafter be waived in respect of the affected network for information reporting purposes in respect of this code, and the Transmission Licensee shall inform the affected Participants of this fact and request the additional data. If the affected network is modified or reinforced to the extent that capacitor banks of 1 MVAR or less no longer cause harmonic resonance problems on the TS, the Transmission Licensee shall inform the affected Participants that information reporting requirements have returned to normal.
- c) The Transmission Licensee, investigating a complaint about harmonic distortion, shall have the right to request such additional information (including, but not

restricted to, data from harmonic distortion measuring devices) from Users in the vicinity of the source of the complaint as may reasonably be required to complete the investigation.

Shunt capacitor or reactor rating	Rating (MVAR)
Reactor/capacitor/harmonic filter	(delete what is not applicable)
Location (station name)	
Voltage rating	kV
Resistance /reactance /susceptance of all components of the capacitor or reactor bank	
Fixed or switched	
If switched	Control details (manual, time, load, voltage, etc.)
If automatic control	Details of settings. If under FACTS device control (e.g. SVC), which device?

21.2.4. Series capacitor or reactor data requirements

- a) Series capacitors are installed in long *Transmission* lines to increase load transfer capability.
- b) Series reactors are installed to limit fault levels, or to balance load sharing between circuits operated in parallel that would otherwise not share load equitably, or to balance load sharing on an interconnected network.

Reactor/capacitor	(delete what is not applicable)
Location (Specify substation bay where applicable)	
Voltage rating	kV
Impedance rating	Ohm or MVAR
Current rating (<i>Continuous and emergency</i> , maximum times for emergency ratings)	Continuous: Hours A Hours A Hours A

Note: if a series capacitor or reactor is located in a dedicated reactor or capacitor station (i.e. a *Substation* built to hold only the series reactor or capacitor), the lines or cables linking it to each remote end *Substation* must be specified as separate circuits under line or cable *data*.

21.2.5. FACTS devices and HVDC data

- a) FACTS devices

- a.1) FACTS devices enable system parameters (voltage, current, power flow) to be accurately controlled in real time. Because of their cost, they are generally used only if cheaper, more conventional, solutions cannot deliver the required functionality.
- a.2) Applications requiring rapid control capability include the following:
- (i) Voltage regulation following loss of a system component, generation, large load, or HVDC link disturbance.
 - (ii) ARC furnace voltage flicker mitigation.
 - 1. Negative phase sequence voltage compensation
 - 2. Sub-Synchronous Resonance (SSR) damping.
 - 3. Machine transient stability enhancement.
 - (iii) System load transfer capability enhancement.
 - (iv) Load sharing control in interconnected, deregulated, networks.
- a.3) The most commonly used FACTS device is the SVC (static Var compensator). Other FACTS devices made possible by advances in power electronics and control systems include STATCON (static condenser), TCSC (thyristor controlled series capacitor), thyristor controlled tap changer, thyristor controlled phase shifter, BES (battery energy storage), and UPFC (unified power controller). The common factor is rapid control capability.
- a.4) Because FACTS devices are purpose-designed for their specific applications, the following data is required:

Name	Station , HV rating, device number
Type	(SVC, STATION, TCSC etc
Configuration: provide a single line diagram showing all HV components and their MVA/MVAR and voltage ratings, with all controlled components identified as such	
Control system : Provide a block diagram of the control system suitable for dynamics modelling	
Resistance /reactance /susceptance of all components of the capacitor or reactor bank	
Primary control mode	Voltage control, ARC furnace flicker mitigation, negative phase sequence voltage control etc

- a.5) Customers are required to perform, or cause to be performed, harmonic studies to ensure that their installation does not excite harmonic resonance, and that harmonic distortion levels at the PCC with the TS do not exceed the limits specified in this Code.
- b) HVDC
- b.1) HVDC is used to connect two systems that are not necessarily interconnected via the AC network (and thus in synchronism), or even at the same nominal frequency.
- b.2) Users wishing to connect HVDC systems to the TS shall supply a single line diagram showing all HV plant (including valve bridges) forming part of the HVDC system, plus additional HV plant required for its proper operation, e.g. harmonic filters, synchronous condensers, FACTS devices, etc. Users and the Transmission System shall cooperate in performing, or causing to be performed, studies to determine network strengthening requirements needed to accommodate the HVDC system without violating the planning criteria specified in the Network Code. In addition, Users shall thereafter perform, or cause to be performed, studies to demonstrate

that the proposed HVDC system does not cause exceedance of QOS parameters, and where applicable shall specify what additional HV plant will be required to ensure compliance with the prescribed QOS standards.

21.2.6. Information on User networks

- a) If a User will have two or more Connection Points with the TS, including the one applied for, the User shall specify the amount of load to be transferred from existing points of supply to the new one under normal conditions as well as under contingencies. The same requirement applies to any embedded generators within the User's network, since they affect fault levels as well as net load on the system;
- b) The User shall also specify whether he intends to interconnect two or more Connection Points through his network. In such circumstances the User shall provide detailed information on the lines and cables used.
- c) Where a circuit consists of two or more segments of different characteristics (different overhead line tower and/or conductor bundle types and/or underground cable types), each section shall be specified separately.

21.2.7. Overhead line data

	Units
Line description	Name ("from Busbar," "to Busbar", circuit number and where applicable, line section number numbered from the "from bus end)
Line voltage (specify separately for dual voltage multi circuit lines)	kV
Single/double/multiple circuit	
Standard suspension tower information (to confirm Impedance) :Supply copy of tower drawing , or sketch drawing showing coordinates of shield wire and phase conductor bundle attachment points relative to tower centre line and ground level at nominal tower height.	
Phase sub conductor type (per circuit)	
Number of subcontractors per phase conductor bundle	
Sub-contractor spacing, if applicable (supply sketch showing phase conductor bundle geometry and attachment point)	mm
Number of earth wires	
Earthwire description	
Line length	km
Conductor parameters (R, X, B, R ⁰ , X ⁰ , B ⁰)	Ohmic values or P.U on 100MVA base specify
Conductor normal and <i>emergency</i> ratings	Ampere or 3 phase MVA at nominal voltage

21.2.8. Cable data

	Units
Line description	Name ("from Busbar," "to Busbar", circuit number and where applicable, line section number numbered from the "from bus end)
Line voltage (specify separately for dual voltage multi circuit lines)	kV
Type (copper/aluminium)	Delete what is not applicable
Size	
Impedance (R, X, B, R ⁰ , X ⁰ , B ⁰)	Ohmic values or P.U on 100MVA base (specify)
Length	km
Continuous and (where applicable) emergency current rating and time limit	Ampere or MVA at nominal voltage maximum at emergency

21.3. APPENDIX 3: GENERATOR PLANNING DATA

Unless otherwise indicated, the following information shall be provided to the *Transmission System*, prior to connection and then updated as and when changes occur.

21.3.1. Power Station data

Generator name	
Power station Name	
Number of Units	
Primary fuel type/prime	For example gas, hydro, fossil or nuclear
Secondary fuel type	For example oil
Capacity requirements	Generation sent out connection capacity require(MW)
"Restart after station Blackout" capacity	Provide a document containing the following Start-up time for the first <i>Generating Unit</i> (time from restart initiation to synchronize) and each of the following units assuming that restarting of units will be staggered.
Black starting capacity	A document stating the number of units that can be black started at the same time, preparation time for the first <i>Generating Unit</i> black starting restarting time for the first <i>Generating Unit</i> , and restating time for the rest of the units.
Partial load rejection capability	A description of the amount of load the <i>Generating Unit</i> can automatically govern back, without any restrictions, as a function of the load at the point of <i>governing</i> initiation.
Multiple <i>Generating Unit</i> tripping (<i>MUT</i>) Risks	A document outlining all systems common to more than one <i>Generating Unit</i> that is likely to cause a <i>MUT</i> . Discuss the measures taken to reduce the risk of <i>MUT</i> .

21.3.2. Generating Unit data

Generating Unit number	
Capacity	Generating Unit Capacity (MW)
	Units
Normal maximum continuous generation capacity:	MW
Normal maximum continuous sent out capacity:	MW
<i>Generating Unit</i> auxiliary active load	MW
<i>Generating Unit</i> auxiliary reactive load	MVar
Maximum (EL1) generating capacity	MW
Maximum (EL2) sent out capacity	MW
Normal minimum continuous generating capacity	MW
Normal minimum continuous sent out capacity	MW
<i>Generator</i> rating (MVA _{base})	MVA
Normal maximum lagging power factor	MVar
Normal maximum leading power factor	MVar
Governor droop	
Forbidden loading zones	MW
Terminal voltage adjustment range	kV
Short circuit ratio	
Rated stator current	Amp
Time to synchronise from warm	Hour
Time to synchronise from cold	Hour
Minimum up-time	Hour
Minimum down-time	Hour
Normal loading rate	MW/min
Normal de-loading rate	MW/min
Can the <i>generator</i> start on each fuel?	
Ability to change fuels on-load	
Available modes (lean burn etc)	

Time to change modes on-load	
Control range for secondary <i>frequency</i> regulation operation	MW
Partial load rejection capability	% <i>MW</i> name plate rating
Minimum time <i>Generating Unit</i> operates in island mode	Hour
Maximum time <i>Generating Unit</i> operates in island mode	Hour

Description	Data
Capability chart showing full range of operating capability of the <i>generator</i> , including thermal and excitation limits	Diagram
Systems that are common and can cause a multiple <i>Generating Unit</i> trip	Description
Open circuit magnetisation curves	Graph
Short circuit characteristic	Graph
Zero power factor curve	Graph
V curves	Diagram

Documents	Description
Protection setting document	<p>A document agreed and signed by the <i>System and Market Operator</i> containing the following:</p> <p>A section defining the base values and per <i>Generating Unit</i> values to be used</p> <p>A single line diagram showing all the <i>Protection</i> functions and sources of current and voltage signals</p> <p>A <i>Protection</i> tripping diagram(s) showing all the <i>Protection</i> functions and associated tripping logic and tripping functions</p> <p>A detailed description of setting calculation for each <i>Protection</i> setting, discussion on <i>Protection</i> function stability calculations, and detailed dial settings on the <i>Protection</i> relay in order to achieve the required setting</p> <p>A section containing a summary of all <i>Protection</i> settings on a per <i>Generating Unit</i> basis</p> <p>A section containing a summary for each of the <i>Protection</i> relay dial settings/programming details</p> <p>An annex containing plant information <i>data</i> (e.g. <i>OEM</i>)</p>

		<p><i>data</i>) on which the settings are based</p> <p>An annex containing <i>OEM</i> information sheets or documents describing how the <i>Protection</i> relays function</p>
Excitation document	setting	<p>A document agreed and signed by the <i>System and Market Operator</i> containing the following:</p> <p>A section defining the base values and per <i>Generating Unit</i> values to be used</p> <p>A single line diagram showing all the excitation system functions and all the related <i>Protection</i> tripping functions</p> <p>An excitation system transfer function block diagram in accordance with IEEE or <i>IEC</i> standard models</p> <p>A detailed description of setting calculation for each of the excitation system functions, discussion on function stability calculations, and detailed dial settings on the excitation system in order to achieve the required setting;</p> <p>A section containing a summary of all settings on a per <i>Generating Unit</i> basis;</p> <p>A section containing a summary for each of the excitation system dials settings/programming details;</p> <p>An annex containing plant information <i>data</i> (e.g. <i>OEM data</i>) on which the settings are based; and</p> <p>An annex containing <i>OEM</i> information sheets or documents describing the performance of the overall excitation system and each excitation function for which a setting is derived.</p>
Governor document	setting	<p>A document agreed and signed by the <i>System and Market Operator</i> containing the following:</p> <p>A section defining the base values and per <i>Generating Unit</i> values to be used;</p> <p>A single line diagram showing all the excitation system functions and all the related <i>Protection</i> tripping functions;</p> <p>An excitation system transfer function block diagram in accordance with IEEE standard models;</p> <p>A detailed description of setting calculation for each of the governor system functions, discussion on function stability calculations, and detailed dial settings on the governor system in order to achieve the required setting;</p> <p>A section containing a summary of all settings on a per <i>Generating Unit</i> basis;</p> <p>A section containing a summary for each of the governor system dial settings/programming details;</p> <p>An annex containing plant information <i>data</i> (e.g. <i>OEM data</i>) on which the settings are based; and</p>

	An annex containing <i>OEM</i> information sheets or documents describing the performance of the overall governor system and each governor function for which a setting is derived
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21.3.3. Reserve Capability

The generator shall provide the System and Market Operator with the reserve capability of each Generating Unit at each Power Station. The reserve capability shall be indicated as per each reserve category: instantaneous reserve, Regulating Reserve, emergency reserve, ten (10)-minute reserve and supplemental reserve.

21.3.4. Generating Unit parameters

	Symbol	Units
Direct axis synchronous reactance	X_d	% on rating
Direct axis transient reactance saturated	$X^{d_{sat}}$	% on rating
Direct axis transient reactance unsaturated	$X^{d_{unsat}}$	% on rating
Sub-transient reactance unsaturated	$X^{d''} = X^{q''}$	% on rating
Quad axis synchronous reactance	X_q	% on rating
Quad axis transient reactance unsaturated	$X^{q_{unsat}}$	% on rating
Negative phase sequence synchronous reactance	X^2	% on rating
Zero phase sequence reactance	X^0q	% on rating
Turbine <i>generator</i> inertia constant for entire rotating mass	H	MW s/MVA
Stator resistance	R_a	% on rating
Stator leakage reactance	X_L	% on rating
Potier reactance	X_p	% on rating
<i>Generator</i> time constants:		
Direct axis open-circuit transient	T_{do}'	sec
Direct axis open-circuit sub-transient	T_{do}''	sec
Quad axis open-circuit transient	T_{qo}'	sec
Quad axis open-circuit sub-transient	T_{qo}''	sec
Direct axis short-circuit transient	T_d'	sec
Direct axis short-circuit sub-transient	T_d''	sec
Quad axis short-circuit transient	T_q'	sec
Quad axis short-circuit sub-transient	T_q''	sec
Speed damping	D	
Saturation ratio at 1 p.u terminal voltage	S(1.0)	
Saturation ratio at 1.2 p.u terminal voltage		

21.3.5. Excitation system

The Generator shall fill in the following parameters or supply a Laplace-domain control block diagram in accordance with IEEE or IEC standard excitation models (or as otherwise agreed with the System and Market Operator) completely specifying all time constants and gains to fully explain the transfer function from the compensator or Generating Unit terminal voltage and field current to Generating Unit field voltage. Customers shall perform, or cause to be performed, small signal dynamic studies to ensure that the proposed excitation system and turbine governor do not cause dynamic instability. Where applicable, a PSS (power system stabiliser) shall be included in the excitation system to ensure proper tuning of the excitation system for stability purposes.

	Symbol	Units
Excitation system type (AC or DC)		Text
Excitation feeding arrangement (solid or shunt)		Text
Excitation system filter time constant	T_r	Sec
Excitation system lead time constant	T_c	Sec
Excitation system lag time constant	T_b	Sec
Excitation system controller gain	K_a	
Excitation system controller lag time constant	T_a	Sec
Excitation system maximum controller output	V_{max}	P.U
Excitation system minimum controller output	V_{min}	P.U
Excitation system regulation factor	K_c	
Excitation system rate feedback gain	K_f	
Excitation system rate feedback time constant	T_f	Sec

21.3.6. Speed governor system, turbine and boiler models

The Generator shall supply a Laplace domain control block diagram in accordance with IEEE standard prime mover models for thermal and hydro units (or as otherwise agreed with the System and Market Operator), fully specifying all time constants and gains to fully explain the transfer function for the governor, turbine, penstocks and control systems in relation to frequency deviations and set-point operation.

21.3.7. Control devices and Protection relays

The *Generator* should supply any additional Laplace domain control diagrams for any outstanding control devices (including power system stabilizers) or special *Protection* relays in the *Generating Unit* that automatically impinge on its operating characteristics within 30 seconds following a system disturbance and that have a minimum time constant of at least 0,02 seconds

21.3.8. Pumped storage

	Symbol	Units
Reservoir capacity		MWh Pumping
Max pumping capacity		MW
Min pumping capacity		MW
Efficiency(generating/pumping ratio)		%

21.3.9. Generating Unit step-up transformer

	Symbol	Units
Number of windings		
Vector group		
Rated current of each winding		Amps
Transformer rating		MVA _{Trans}
Transformer nominal LV voltage		kV
Transformer nominal HV voltage		kV
Tapped winding		
Transformer ratio at all transformer taps		
Transformer impedance at all taps (For three winding transformers the HV/LV1, HV/LV2 and LV1/LV2 impedances together with associated bases shall be provided)		%on rating MVA _{Trans}
Transformer zero sequence impedance at nominal tap	Z^0	Ohm
Earthing arrangement, including neutral earthing resistance and reactance		
Core construction (number of limbs, shell or core type)		
Open circuit characteristic		Graph

21.3.10. Generating Unit forecast data

The *generator* shall provide to the *Single Buyer* with expected maintenance requirements, in weeks per annum, for each *Generating Unit* at a *Power Station*.

21.3.11. Mothballing of generating plant:

Mothballing of generating plant is the withdrawal of plant from commercial service for six *Months* or longer, with the intention of returning it to commercial service at a later date. Mothballing can have a profound impact on the operation and integrity of the *TS*.

Conditions applicable to Mothballing of generating plants shall be governed by the clauses contained in their Contract with the Single Buyer

Users wishing to mothball generating plant shall supply the *Single Buyer* with the following information:

Generator name	
Power Station name	
Generating Unit number	
Date withdrawn	Date <i>Generating Unit</i> is to be withdrawn from commercial service
Return to commercial service	Envisaged return to service (re-commissioning tests completed and <i>Generating Unit</i> available for commercial service
Auxiliary power requirements	

21.4. APPENDIX 4: GENERATOR MAINTENANCE DATA

The 52-weeks-ahead outage plan per week per *generator* shall be supplied weekly to the System and Market Operator

Generator:

DATE (week starting)				
WEEK NUMBER	n	n+1	n +51
MAINTENANCE (MW)				
WEEKEND OUTAGES	0	0	0	0
Power station 1	0	0	0	0
Power Station 2	0	0	0	0
Power Station 3	0	0	0	0
Power Station n	0	0	0	0
TOTAL MAINTENANCE				
FUTURE KNOWN UNPLANNED				
MAJOR CHANGES SINCE LAST WEEK:				
Notes				
FUTURE KNOWN UNPLANNED	a)			
	b)			

The annual maintenance/outage plan per *generator*, looking five years ahead, shall be supplied to the *System and Market*;

The format shall be as per the 52-weeks-ahead outage plan per week per *generator*, but extending for five years; and

A monthly variance report, explaining the differences between the above two reports, shall be supplied to the *System and Market*

VARIANCE REPORT TEMPLATE

Station and	MW	Start - Date	Outage- Completion Date				
Outage code	Cap	official	official	Revised	Urgent	Outage description	Reason for Difference

21.5. APPENDIX 5: OPERATIONAL DATA

***Note:** The content of this Appendix is excessively detailed as to be included in a Grid Code. It contains details about is Sub-section fields and status to be used in exchanging information between SCADA systems, details about switchgear configurations and nomenclature, etc.*

This level of detail, although important, should be excluded from the GC and replaced by specific instructions / procedures issued by the System and Market Operator. Otherwise, a simple change in the SCADA control room may imply changes in the GC content.

- 21.5.1. This appendix specifies the *data* format to be used by the SCADA system for the mapping of *RTU data* into the SCADA database. The *data* base has a definition for each electrical configuration (ELC) or electrical object in the station. Each ELC definition specifies a different ELC type, e.g. transformers, units, feeders, etc, and is accompanied by a picture showing the ELC and all its associated devices as they would be indicated on the *System and Market* operational one-line displays. In each instance, the picture defines the primary devices and is followed by the points belonging to each device;

21.6. APPENDIX 7: POST-DISPATCH INFORMATION

21.6.1. The System and Market Operator shall provide the following minimum operational information in near real-time and as historic data in relation to each Generating Unit at each Power Station:

No.	Data entity	Data Description	Format	Size	Unit
1	Generating Unit high limit		Real	99,999	
2	Generating Unit low limit	CER/BLO	Real	99,999	
3	Generating Unit AGC mode	AUT/OFF/MAN	Character	3	Hour (h)
4	Generating Unit AGC status		Character	3	MW
5	Generating Unit set-point		Real	99,999	'F'/'I'
6	AGC pulse		Real	99,999	'Y'/'N'
7	Generating Unit sent-out		Integer	99,999	MW
8	Generating Unit auxiliary		Integer	999	MW
9	Generating Unit contract		Integer	999	MW
10	Generating Unit spinning		Integer	999	MW
11	AGC flag	32-bit flag on AGC settings	Integer		32 bits

21.6.2. If Malawi is a *control area* then the *System and Market Operator* shall provide the following minimum operational information in near real-time in relation to the overall dispatch performance:

No.	Data entity	Data Description	Format	Size	Unit
1	ACE	Area Control Error	Real	99,999	MW
2		Average ACE previous hour	Real	99,999	MW
3	HZ	System frequency	Real	99,999	MW
4		Frequency distribution current hour	Real	99,999	MW
5		Frequency distribution previous hour	Real	99,999	MW
6		system total generation	Integer	99,999	MW
7		Control area total actual interchange	Integer	99,999	MW
8		Control area total actual scheduled interchange	Integer		MW
9		System Operating reserve	Integer	99,999	MW
10		System Sent-out	Integer	99,999	MW
11		System spinning Reserve	Integer	99,999	MW

12		AGC regulating up	Integer	99,999	MW
13		AGC regulating down	Integer	99,999	MW
14		AGC regulating up assist	Integer	99,999	MW
15		AGC regulating down assist	Integer	99,999	MW
16		AGC regulating up <i>emergency</i>	Integer	99,999	MW
17		AGC regulating down emergency	Integer	99,999	MW
18		AGC mode	Character	TLBC/CFC	
19		AGC status	Character		
20		Area Control Error output	Real	99,999	MW
21		System Transmission losses	Real	99,999	MW
22		AGC Performance Indicators			

21.7. APPENDIX 8: GENERATOR PERFORMANCE DATA

Note: Measures of Availability shall be defined in the PPA Contracts between the Single Buyer and the Generator, which may be different from the metrics proposed here. It is recommended, therefore, not to include this Appendix in the GC.

21.8. APPENDIX 9: PLANNING SCHEDULES

21.8.1. Schedule 1: Ten-year demand forecast

	Demand= Total Demand+ Distribution Losses-Embedded Generation					
			Maximum demand		Expected demand	
Year		GWh	MW	MVA _r	MW	MVA _r
Measured Year 0						
Year 1						
Year 2						
Year 3						
Year 4						
Year 5						
Year 6						
Year 7						

