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WESM Manual

System Security and Reliability Guidelines

Issue 1.0 | WESM-SSRG

This manual prescribes general guidelines that must be followed by all WESM Participants to maintain the security and reliability of the Luzon, Visayas and Mindanao power systems.

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In case of inconsistency between this document and the DOE Circulars, the latter shall prevail.

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	SO Subcommittee		New Document
1.0	National Grid Corporation of the Philippines	03 August 2016	Revisions were made to align pertinent provisions of the WESM Manual on System Security and Reliability Guidelines with the changes in the power industry due to the technical requirement and stricter implementation of applicable/amended rules of the Grid Code.
	PEMC	26 Jun 2021	Revised formatting for the commencement of the enhanced WESM design and operations per DOE Department Circular No. DC2021-06-0015.

Document Approval

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**Declaring the Commercial Operations of Enhanced WESM Design and Providing Further Policies*

Reference Documents

Document ID	Document Title
	WESM Rules
	Philippine Grid Code
WESM-PDM	Price Determination Methodology

Contents

SECTION 1 INTRODUCTION

Power system reliability is a major concern in the Philippine electricity industry. It encompasses all aspects of providing reliable electric service to customers, which is a daunting task. A reliable power system is one that accounts for few interruptions of service to customers.

Power system reliability is generally considered to have two components: resource adequacy and system security. Resource adequacy refers to having sufficient resources in place in a timely manner to produce and deliver power on demand and to provide a “buffer” (e.g., a reserve margin) to cover contingencies associated with unplanned electricity demand increases and unplanned electricity supply reductions. In plain language, adequacy implies that there are sufficient generation and transmission resources available to meet projected needs plus reserves for contingencies. These contingencies can affect both production (generation) and delivery (transmission and distribution).

Security refers to the system’s ability to react to and withstand disturbances. It implies that the system will remain intact even after outages or other equipment failures occur. It involves having sufficient equipment and procedures in place to avoid harm to customers and to the electric system (generation, transmission and distribution) in case of disturbances. Disturbances can include adverse weather, equipment failures, and other events that could lead to an overload of the system or portions of the system. System security typically addresses emergency operations that occur over short times (from seconds to hours), often requiring activation and operation of automatic protection devices and generally involving intervention by the System Operator. Although System Operator must be able to respond quickly to disturbances, there are limits to their ability to intervene. Automatic protection devices are used where actions may be required before operator intervention is possible (e.g., response to a lightning strike occurs automatically within a few cycles). Effective system security requires a high degree of coordination, communication, and control on a real-time basis.

Unlike most products, electricity cannot be stored in large quantities in an economical manner. As a result, electricity has to be produced and delivered on demand. The operating capability of the generation, transmission, and distribution systems must be sufficient to meet constantly changing customer demands at all times.

Another distinguishing characteristic of electricity supply systems is the high degree of interdependence between generation and transmission. As a result of this interdependence, disturbances in generation may lead to transmission problems. For example, a major generation unit outage can quickly lead to an overload condition on the transmission system, which may result in transmission outages and loss of delivered power. Similarly, disturbances in transmission may lead to generation problems. For example, a transmission outage resulting from adverse weather or an overload condition may quickly lead to generation outages and loss of delivered power. Currently system protection features are built in to limit the extent of disturbances and the possibility of equipment damage.

These facets of electrical systems place a premium on rapid response operation to maintain system reliability. Rapid response operation must occur within seconds or minutes of changes in system conditions. These two unique characteristics also lead to the following four reliability consequences that dominate nearly all aspects of power system operation:

(a) Every action can affect all other activities on the grid. Therefore, the activities of all players must be coordinated;

(b) Cascading problems that increase in severity are extremely serious. Failure of a single element of the system can, if not managed properly, cause the subsequent rapid failure of many additional elements, disrupting the entire transmission system;

(c) The need to be ready for the next contingency dominates the design and operation of the bulk power system to a greater degree than do current conditions. It is usually not the present flow through a line or transformer that limits allowable power transfers, but rather the flow that would occur if another element fails; and

(d) Because electricity flows at the speed of light, maintaining reliability often requires that actions be taken instantaneously (within fractions of a second), which necessitates automatic computing, communication, and control actions.

Managing reliability raises important commercial and societal issues. Reliability rules can favor some industry players and exclude others, and these rules affect all of society because they affect electricity prices and availability. All users of the power system have an interest in how reliable the system is, what the costs of reliability are, and how decisions concerning reliability are made.

To Customers, the most important characteristics of a reliable power system are:

(a) Widespread adverse effects on customer service are minimized;

(b) Outages are confined in extent;

(c) The system can be restored rapidly after an outage; and

(d) The cost to Customers is in accord with their reliability expectations and willingness to pay.

SECTION 2 DEFINITION OF TERMS

Adequacy. The ability of the power system to supply the aggregate electrical demand and energy requirements of the Customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.

Automatic Generation Control (AGC). The regulation of the power output of generating units within a prescribed area in response to a change in system frequency, tie-line loading, or the relation of these to each other, so as to maintain the system frequency or the established interchange with other areas within the predetermined limits or both.

Automatic Load Dropping (ALD). The process of automatically and deliberately removing pre-selected loads from a power system in response to an abnormal condition in order to maintain the integrity of the system.

Backup Reserve (also called cold standby reserve). Refers to a generating unit that has fast start capability and can synchronize with the grid to provide its declared capacity for a minimum period of eight (8) hours.

Black Start. The process of recovery from total system blackout using a generating unit with the capability to start and synchronize with the system without an external power supply.

Cascading Outage. The uncontrolled successive loss of system elements triggered by an incident at any location.

Contingency. The unexpected failure or outage of a system component, such as a generator, transmission line, power transformer, bus, circuit breaker, or other electrical element. A contingency may also include multiple components, which are related by situations leading to simultaneous component outages.

Contingency Reserve. The generating capacity that is intended to take care of the loss of the largest synchronized generating unit or the power import from a single grid interconnection, whichever is larger. Contingency reserve includes spinning reserve and backup reserve.

Disturbance. An unplanned event that produces an abnormal system condition.

Emergency. Any abnormal system condition that requires automatic or immediate manual action to prevent or limit loss of transmission facilities or generation supply that could adversely affect the reliability of the electric system.

Fault. An event occurring on an electric system such as a short circuit, a broken wire, or an intermittent connection.

Island Grid. A portion of a power system or several power systems that is electrically separated from the interconnection due to the disconnection of transmission system elements.

Load Following and Frequency Regulating (LFFR) Reserve. The amount of generating capacity that provides for following the moment-to-moment variations in demand or supply in a power system and for maintaining acceptable system frequency.

Manual Load Dropping (MLD). The process of manually and deliberately removing pre-selected loads from a power system in response to an abnormal condition in order to maintain the integrity of the system.

Multiple Outage Contingency. An event caused by the failure of two (2) or more components of the grid including generating units, transmission lines, and transformers.

Normal State. The grid operating condition when the system frequency, voltage, and transmission line and equipment loading are within their normal operating limits, the operating margin is sufficient, and the grid configuration is such that any fault current can be interrupted and the faulted equipment isolated from the grid.

Operating Margin. The margin of generation over the total demand plus losses that is necessary for ensuring power quality and the security of the grid. Operating margin is the sum of the load following and frequency regulating reserve and the contingency reserve.

Reliability. The performance of the elements of the bulk electric system that results in electricity being delivered to Customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply.

Security. The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

Single Outage (N-1) Contingency. An event caused by the failure of one component of the grid including a generating unit, transmission line, or transformer.

Spinning Reserve (also called hot standby reserve). The component of contingency reserve which is synchronized to the grid and ready to take on load.

Stability. The ability of the dynamic components to return to a normal or stable operating point after being subjected to some form of change or disturbance.

System Integrity Protection Scheme (SIPS). A protection system that is designed to detect abnormal or predetermined system conditions, and take automatic corrective actions.

Voltage Collapse. An event that occurs when an electric system does not have adequate reactive support to maintain voltage stability. Voltage collapse may result in outage of system elements and may include interruption in service to Customers.

Voltage Control. The control of transmission voltages through adjustments in generator reactive output and transformer taps and by switching capacitor and reactors on the transmission and distribution systems.

SECTION 3 OBJECTIVE

Preservation of system reliability and security is the primary objective of these guidelines and is the responsibility of the System Operator. This mandate is clearly vested under Clause 3.8.2.1 (b) of the WESM Rules which stipulates that, during each trading interval, the System Operator shall use its reasonable endeavors to maintain system security consistent with the requirements of the Grid Code. Minimization of customer service interruptions and quick restoration of the power system to the normal state are secondary objectives of these guidelines.

This document prescribes general guidelines that must be followed by all WESM Participants to maintain the security and reliability of the Luzon, Visayas and Mindanao power systems. These guidelines are based on existing practices and the Grid Code and Distribution Code requirements and developed in accordance with Clause 6.6.1.1 of the WESM Rules which states that the System Operator, in consultation with WESM Participants and the Market Operator, shall develop and periodically update system security and reliability guidelines, subject to approval of the PEM Board. These guidelines provide supplementary provisions for the improvement of WESM operations in ensuring the security and reliability of the grid. However, in case of conflict in the achievement of the objectives of the Grid Code, the provisions of the Grid Code shall prevail.

SECTION 4 SCOPE

These guidelines apply to the following WESM Participants:

(a) Market Operator;
(b) System Operator;
(c) Generation Companies;
(d) Ancillary Service Providers;
(e) Distribution Utilities;
(f) Suppliers;
(g) Bulk Consumers/End-users; and
(h) Other similar entities, authorized by the Energy Regulatory Commission (ERC) to become members of the WESM.

SECTION 5 GUIDELINES

The power system shall be operated to achieve the highest practical degree of service reliability. Appropriate remedial actions shall be taken promptly to eliminate any abnormal conditions which jeopardize reliable operation.

5.1 Normal State Operation

The grid shall be operated so that it remains in the normal state, i.e.:

(a) The operating margin is sufficient.
(b) The grid frequency is within the limits as set forth in the Grid Code.
(c) Voltages at all connection points are within the limits of 0.95 and 1.05 of the nominal value.
(d) The loading levels of all transmission lines and transformers are below the limit as set forth in the Grid Code.
(e) The grid configuration is such that any potential fault current can be interrupted and the faulted equipment can be isolated from the grid.
(f) The static and dynamic stability of the power system is maintained.
(g) The single outage contingency (N-1) criterion is met.

5.2 Alert State

The Grid shall be considered to be in the alert state when any one of the following conditions exists:

(a) The voltages at the connection points are outside the limits of -5% and +5% but within the limits of -10% and +10% of the nominal value;
(b) There is critical loading or imminent overloading of transmission lines or substation equipment;
(c) A weather disturbance has entered the Philippine area of responsibility, which may affect grid operations;

(d) Peace and order problems exist, which may pose a threat to grid operations;
(e) The operating margin is not sufficient to replenish the sudden loss of the largest generating unit capacity synchronized to the grid; and
(f) The grid frequency is beyond the limits of 59.7 Hz and 60.3 Hz but within the thresholds of 59.4 Hz and 60.6 Hz.

5.3 Emergency State

The grid shall be considered in the emergency state when:

(a) Single outage contingency (N-1) criterion is not met. Imminent threat in system security would exist should a credible n-1 contingency occur that would result in the cascading outages of lines and equipment if not corrected immediately;
(b) There is generation deficiency or operating margin is zero;
(c) Grid transmission voltage is outside the limits of -10% or +10% of the nominal value;
(d) The loading levels of all transmission lines and substation equipment are beyond the threshold as set by the Grid Code; and
(e) The grid frequency is beyond the limits of 59.4 Hz and 60.6 Hz.

5.4 Single Outage (N-1) Contingency Criterion

(a) The security and reliability of the grid shall be based on the single outage contingency (N-1) criterion. This criterion specifies that the grid shall continue to operate in the normal state following the loss of one generating unit, transmission line, or transformer.

(b) Credible single outage contingency (N-1) contingencies

The N-1 Criterion is related to one of the following contingencies:

(i) Loss of a single-circuit transmission line, except those radial circuits which connect loads using a single line or cable;
(ii) Loss of one circuit of a double-circuit transmission line;
(iii) Loss of submarine cable;
(iv) Loss of a single transformer, except those which connect loads using a single radial transformer;
(v) Loss of a generating unit, whether grid-connected or embedded; and
(vi) Loss of compensating devices, i.e., capacitor / reactor / SVC

(c) In the event of a credible N-1 contingency, the system or any part thereof shall be operated up to its operational thermal limit capacity, beyond which the System Operator shall intercept to restore system stability.

For the avoidance of doubt, manual corrective interventions shall not be imposed to delimit the power transfer capabilities of equipment/transmission lines in anticipation of a secondary outage (N-1-1). However, if a significant threat to system security exists following the occurrence of a credible N-1 contingency the System Operator may intervene and shall make the necessary manual corrective actions as required, to protect the integrity of the grid.

(d) The power system shall be operated at all times in such a manner that system instability, islanding, cascading outages, or voltage collapse will not occur as a result of the most severe single contingency. A single contingency may generally be assumed to mean the loss of a single system element; however, the outage of multiple system elements should be treated as a single contingency if caused by a single event of sufficiently high likelihood.

(e) Multiple contingency outages of a credible nature shall be examined, and the system shall be operated to protect against system instability, islanding or cascading outages for these contingencies.

(f) A planned activity notice or request for shutdown shall be issued by a grid user to the System Operator for any planned activity such as a planned shutdown or scheduled maintenance of its equipment at least seven (7) days prior to the actual shutdown or maintenance. This is to allow the System Operator sufficient time to evaluate if the planned outage can be accommodated by the power system and to coordinate the outage with other affected grid users. The System

Operator shall notify the user of its approval or disapproval of the user's request at least five (5) days before the actual work commences.

5.5 Grid Operation Notices

The following notices shall be issued, without delay, by the System Operator to notify all grid users of an existing alert state:

(a) Yellow alert when the contingency reserve is less than the capacity of the largest synchronized generating unit or power import from a single interconnection, whichever is higher;

(b) Red alert when the contingency reserve is zero or generation deficiency exists or if there is critical loading or imminent overloading of transmission lines or equipment;

For clarity, when the operating margin net of the regulating reserve capacity is less than the capacity of the largest synchronized generating unit or power import from a single interconnection, whichever is higher, the System Operator shall issue yellow alert notice.

Likewise, if the operating margin less the regulating reserve capacity becomes zero, the System Operator shall issue red alert notice.

(c) Weather disturbance alert when a weather disturbance has entered the Philippine area of responsibility;

(d) Blue alert when a tropical disturbance is expected to make a landfall within twenty-four (24) hours; and

(e) Security red alert when peace and order problem exist, which may affect the grid operations.

5.6 Voltage and Reactive Power Control

(a) The grid voltages shall be operated at safe levels to reduce the vulnerability of the grid to transient instability, dynamic instability, and voltage instability problems. Reactive reserve margins shall be adequate to maintain minimum acceptable voltage limits under facility outage conditions.

(b) The control of voltage shall be achieved by managing the reactive power supply in the grid. These include the operation of the following equipment:

- (i) Synchronous generating units;
- (ii) Synchronous condensers;
- (iii) Shunt capacitors;
- (iv) Shunt reactors;
- (v) Static var compensators (SVCs); and
- (vi) On-load tap-changing transformers.

(c) Operation of static and dynamic reactive devices shall be coordinated such that static devices are switched in or out of service so that the maximum reactive reserves are maintained on generators, synchronous condensers and other dynamic reactive devices.

(d) Reactive resources shall be dispersed and located electrically so that they can be applied effectively and quickly when contingencies occur. Sufficient reactive resources that are available and operable shall be ensured by the System Operator through its own facilities and by the procurement of reactive power support services.

(e) As a last resort, especially during light load conditions, some transmission lines may be switched off to reduce the charging MVars (capacitive reactive power) in the system and to keep the voltages within allowable limits. Transmission lines may be removed from service only after studies indicate that system reliability will not be degraded below acceptable levels.

(f) Necessary corrective actions, including load reduction, shall be taken to prevent voltage collapse when reactive resources are insufficient.

(g) All generating units with automatic voltage control equipment shall normally be operated in voltage control mode. When a generator's voltage regulator is out of service, field excitation shall be maintained at a level sufficient to maintain generator stability.

5.7 Frequency Control

(a) The grid frequency shall be controlled by the timely use of frequency regulating reserve, contingency reserve, and demand control such as automatic load dropping (ALD) and/or manual load dropping (MLD) during emergency conditions.

(b) A generating unit providing regulating and/or contingency reserves may be operated either in an automatic frequency-sensitive mode (also known as free-governor mode) with primary response or in an automatic generation control (AGC) mode with secondary response.

(c) A generating unit providing primary response for frequency regulation as an ancillary service shall operate in an automatic frequency-sensitive mode (also known as free-governor mode) for automatic response of the unit's power output to changes in frequency. The speed-governing system of the generating unit shall have a maximum response time of five (5) seconds.

(d) Secondary response shall be required from selected generating units providing ancillary services for frequency regulation. Frequency control using the secondary response of the generating units shall be accomplished through automatic generation control (AGC) or manual adjustment of generation with specific dispatch instructions from the System Operator. The maximum response

time for the change in the unit's power output shall be twenty-five (25) seconds and which shall be sustainable for at least thirty (30) minutes.

(e) The generation company or power plant shall not override the free-governor mode or automatic generation control (AGC) mode of a generating unit which is providing primary or secondary response.

(f) Governors shall not be blocked and shall not be operated with excessive deadbands. To provide an equitable and coordinated system response to generation-load imbalances, governor droop shall be set at 5%.

(g) A generating unit providing contingency reserve as an ancillary service shall be synchronized with the grid at the start of every trading interval to be able to automatically respond to any sudden loss or significant reduction in generating capacity.

(h) In case the system frequency momentarily rises to 62.4 Hz or falls to 57.6 Hz, all generating units shall remain in synchronism with the grid for at least five (5) seconds to allow the System Operator to undertake measures to correct the situation.

5.8 System Reserve Requirements

(a) Sufficient system reserves shall be available at all times to maintain acceptable system frequency, necessary to cope with any load variations and errors in load forecasting and to replace generating capacity lost due to forced outages of generation and transmission equipment. Adequate frequency regulating reserve and contingency reserve shall be available to stabilize the system and facilitate the restoration to the normal state following a multiple outage contingency.

(b) The operating margin of the grid is sufficient if the available generating capacity in excess of the sum of the system demand plus losses is greater than the capacity of the highest synchronized generating unit within a specific period of time to cover loss of a generating unit or the power import from a single circuit interconnection whichever is higher.

(c) The required system reserves for regulating and contingency shall be in accordance with the latest ERC approved ancillary service procurement plan.

5.9 Demand Control

(a) If demand control due to generation deficiency needs to be implemented, the System Operator shall issue a red alert warning by 1600H, a day ahead. The red alert warning shall specify the amount, the period during which the demand reduction will be required and the reason of the generation deficiency.

(b) The System Operator shall issue demand control imminent warning when a demand reduction is expected within the next thirty (30) minutes. The demand

control imminent warning shall be effective for one (1) hour and shall be automatically cancelled if it is not re-issued by the System Operator.

(c) During demand control, the implementation of real time dispatch shall cease and the System Operator, in coordination with the Market Operator, shall declare market intervention.

(d) The user shall provide the System Operator with the amount of demand reduction actually achieved after the implementation of demand control.

(e) The user shall abide by the instruction of the System Operator with regard to the restoration of demand. The restoration of demand shall be achieved as soon as possible and the process of restoration shall begin within two (2) minutes after the instruction is given by the System Operator.

(f) The demand control shall include the following:
- (i) Automatic load dropping;
- (ii) Manual load dropping;
- (iii) Demand reduction on instruction by the System Operator; and
- (iv) Voluntary demand management.

5.10 Automatic Load Dropping (ALD) and Manual Load Dropping (MLD)

(a) Adequate load shedding facilities initiated automatically by frequency conditions outside the normal operating frequency excursion band shall be available and in service to restore the frequency to normal following the loss of one (1) or more generating units or other significant contingency events. A load shedding program shall be implemented to drop the necessary amount of load to arrest frequency decay, minimize loss of load, and permit timely system restoration.

(b) The level of demand required for ALD shall be established by the System Operator in order to limit the consequences of a major loss of generation in the grid. Appropriate technical studies shall be conducted by the system Operator to justify the targets and/or to refine them as necessary.

(c) Loads that are subject to ALD shall be split into rotating discrete MW blocks. The number of blocks and the under frequency setting for each block shall be specified by the System Operator.

(d) If an ALD has taken place, the affected users shall not reconnect their feeders without clearance from the System Operator. The System Operator shall issue the instructions to reconnect once the frequency of the grid has recovered.

(e) To ensure that a subsequent fall in frequency will be contained by the operation of ALD, additional manual load dropping (MLD) shall be implemented so that the loads that were dropped by ALD can be reconnected.

(f) MLD shall be conducted by distributors, as directed by the System Operator, in response to an overall shortage of energy at a node or in a region specified in the network market model, or other network conditions as determined by the System Operator in accordance with the procedures established under the Grid Code and Distribution Code.

(g) To prepare for a generation deficiency situation, a priority scheme for MLD based on equitable load allocation shall be established by distributors in consultation with the System Operator.

(h) Immediately following the issuance by the System Operator of an instruction to implement MLD, distributors shall make arrangement that will enable it to disconnect its scheduled Customers.

(i) MLD may also be initiated by the System Operator in response to any other circumstances which it reasonably considers necessitate such action under the Grid Code or Distribution Code or any other applicable regulatory instrument.

(j) Customers affected by the MLD shall not be reconnected by distributors until instructed by the System Operator to do so.

5.11 System Restoration

(a) A coordinated system restoration plan shall be established, reviewed, updated if necessary, and simulated to verify comprehensiveness and feasibility.

(b) Following a significant incident that makes it impossible to avoid island grid operation, the grid shall separate into several self-sufficient island grids, which shall be resynchronized to restore the grid to the normal state.

(c) If a part of the grid is not connected to the rest of the grid, but there is no blackout in that part of the grid, the resynchronization of that part to the grid shall be undertaken by the System Operator.

(d) Sufficient black start and fast start capacity shall be available at strategic locations to facilitate the restoration of the grid to the normal state following a total system blackout. At least two (2) black start plants shall be available at each power restoration highway or sub-grid. Each black start generating unit shall be tested to verify that it can be started and operated without being connected to the system.

(e) Emergency drills shall be conducted at least once a year to familiarize all personnel responsible for emergency and grid restoration activities with the emergency and restoration procedures. The drills shall simulate realistic emergency situations. A drill evaluation shall be performed and deficiencies in procedures and responses shall be identified and corrected.

5.12 Grid Protection Requirements

(a) Grid protection shall be designed, coordinated, tested and maintained to achieve the desired level of speed, sensitivity, and selectivity in fault clearing and to minimize the impact of faults on the grid.

(b) The grid shall have adequate and coordinated primary (Main 1 and Main 2) and local and remote backup protection at all times to limit the magnitude of grid disturbances when a fault or equipment failure occurs. Preferably, the Main 1 and Main 2 protection should be of different types (e.g. distance relay for Main 1 and current differential relay for Main 2) and use different teleprotection media (e.g. power line carrier or optical fiber for Main 1 and microwave for Main 2).

(c) High-speed relays, high-speed circuit breakers and automatic reclosing shall be used where studies indicate the application will enhance stability margins. Single-pole tripping and reclosing may be appropriate on some lines.

(d) Circuit breaker fail protection shall be designed to initiate the tripping of all the necessary electrically adjacent circuit breakers and to interrupt the fault current within the next fifty (50) milliseconds, in the event that the primary protection system fails to interrupt the fault current within the prescribed fault clearance time.

(e) Protection system applications, settings, and coordination shall be reviewed periodically and whenever major changes in generating resources transmission, load or operating conditions are anticipated.

(f) The operation of the complete protection system shall be tested under conditions as close to actual operating conditions as possible, including actual circuit breaker operation where feasible.

(g) Relays that have misoperated or are suspected of improper operation shall be promptly removed from service until repaired or correct operation is verified.

(h) The fault clearance time for a fault on the grid shall not be longer than:
- (i) 85 ms for 500 kV;
- (ii) 100 ms for 230 kV and 138 kV; and
- (iii) 120 ms for voltages less than 138 kV.

(i) Following a credible N-1 contingency where the Rules for a minimum grid performance are compromised, a temporary security measure such as the system integrity protection scheme (SIPS) shall be employed to avoid subsistence and spreading of the disturbance.

The temporary employment of SIPS shall be coordinated with the concerned users and shall only be applied specific to parts of the system determined to be exposed to a high degree of likelihood for a secondary contingency (N-1-1) or a subsequent multiple contingency (N-x) such that the risk of cascaded blackout is avoided.

Information on all available SIPS shall be provided to the Grid Management Committee and at the same time, it shall be coordinated with the concerned users.

(j) The installation and use of transient recorders, event recorders and other recording devices should be encouraged as an aid in analyzing performance during system disturbances.

5.13 Telecommunications Requirements

(a) For a high degree of service reliability under normal and emergency operation, it is essential that adequate and reliable communication facilities be provided within a grid and between grids. When possible, these facilities shall be redundant and diversely routed.

(b) At least one (1) main communication channel with an alternate backup channel shall be provided between the national control center and the regional control centers, between the national / regional control center and the area control centers, between the control centers and the power plants, and between the control centers and the substations.

(c) Separate telecommunication channels shall be provided for SCADA, automatic generation control (AGC), protective relaying, special protection systems, voice and data where appropriate.

(d) All telecommunications channels shall be tested regularly or monitored on line.

(e) Communication facilities shall be provided with an automatic standby emergency power supply adequate to supply requirements for a prolonged interruption.

SECTION 6 RESPONSIBILITIES

The System Operator shall:

(a) Make the necessary manual interventions upon existence of an imminent threat in system security or a credible N-1 contingency to restore back, without delay, the grid operating condition to normal state;

(b) Initiate, upon the existence of a credible N-1 contingency, any or a combination of manual corrective interventions as follows:

- (i) Switch off, or re-route, energy delivery from a Generation Company;
- (ii) Call equipment into service;
- (iii) Take transmission line or equipment out of service;
- (iv) Commence operation of generating units or maintain, increase or reduce active or reactive power output of the same;
- (v) Increase, reduce output of generating units or shut down or otherwise vary operation of the same; and shed or restore load;

(c) Notify the user of its approval or disapproval of the planned activity notice (PAN) request at least five (5) days before the actual work commences;

(d) Constrain-on / constrain-off or make use of MRUs whenever all available ancillary reserves are depleted or exhausted;

(e) Implement demand control as a last resort in order to ensure the stability and security of the grid;

(f) Propose a uniform required deadband applicable to all generators; and

(g) Issue necessary alert notices upon existence of qualifying threat.

SECTION 7 AMENDMENTS, PUBLICATION AND EFFECTIVITY

7.1 Amendments

Any amendments to this Manual shall be approved by the PEM Board, following the procedures for changes to the Market Manual set out in the WESM Rules and in the relevant Market Manual.

7.2 Publication and Effectivity

This Market Manual, as it may be amended from time to time, shall be published in the market information website maintained by the Market Operator.

This Market Manual or any amendments thereto shall become effective upon approval of the DOE in accordance with the WESM Rules Clause 8.6.4. The date of effectivity shall be indicated in this document.