ANNEX "A"

ANCILLARY SERVICES PROCUREMENT PLAN

Rules, Terms and Conditions for the provision of

OPEN ACCESS TRANSMISSION SERVICE

Energy Regulatory Commission

ERC Case No. _____

Draft November 2011

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1.0 Introduction

1.1 Objectives for the Ancillary Services Procurement Plan

This Ancillary Services Procurement Plan has been developed to inform electric power industry participants how the Transmission Provider, which is currently the National Grid Corporation of the Philippines, will procure and arrange Ancillary Services to support the operation of the Philippines Power System, in coordination with the Market Operator, as required by the Electric Power Industry Reform Act of 2001 (EPIRA), the Implementing Rules and Regulations of Republic Act No. 9136 (the IRR), the Grid Code and the WESM Rules.

1.2 Definition of Terms

Active Power - The time average of the instantaneous power over one period of the electrical wave measured in Watts (W) or multiple 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.

Ancillary Service - Support services that are necessary to support the transmission capacity and flow of Active Power in order to maintain power quality and the reliability and security of the Grid. Ancillary Services covered by this Ancillary Services Procurement Plan include Regulating Reserve, Contingency Reserve, Dispatcable Reserve, Reactive Power Support and Black Start.

Ancillary Services Provider – A person or entity providing Ancillary Services regardless of whether it is duly registered or not with the Market Operator, provided, however, that upon certification by the Transmission Provider and prior to trading in the WESM, it shall register with the Market Operator.

Apparent Power. The product of the root-mean-square (RMS) or effective value of the current and the root-mean-square value of the voltage. For AC circuits or systems, it is the square root of the sum of the squares of the Active Power and Reactive Power, measured in volt-ampere (VA) or multiples thereof.

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

Black Start – As defined in clause 3.1.5.

Concessionaire – The concessionaire is currently the National Grid Corporation of the Philippines (NGCP), or as otherwise approved under Philippines law from time to time.

Contingency Reserve (CR) – As defined in the WESM Rules. A more detailed description is provided in clause 3.1.2.

Dispatch Instructions – A verbal or written notice of the scheduled generating units providing Regular Energy Supply and the scheduled generating units and interruptible loads providing Ancillary Services, which has been developed by the System Operator in coordination with the Market Operator, in order to achieve the operational requirements of balancing load Demand with generation Supply that will ensure the Safe and Reliable operation of the Grid.

Dispatch Period – A period of time being a multiple of the trading interval defined for the WESM, in which a generating unit is scheduled by the System Operator to provide Regular Energy Supply or Ancillary Services.

Dispatachable Reserve (DR) – As defined in the WESM Rules. A more detailed explanation is provided in clause 3.1.3.

Energy Management System (EMS) – An electronic monitoring and control system available to the System Operator to monitor and control the Grid. For the purposes of this ASPP, the EMS system includes the control hardware and software used to remotely monitor and control the generators feeding energy into the Grid or providing Ancillary Services.

Energy Regulatory Commission (ERC) - The independent, quasi-judicial regulatory body created pursuant to R.A. No. 9136, which is mandated to promote competition, encourage market development, ensure customer choice, and penalize abuse of market power in the restructured electricity industry and among other functions, to promulgate and enforce the Grid Code and the Distribution Code.

Excess Capacity – For a generator, excess capacity is the available Active Power output capacity in MW less the Regular Energy Supply, Frequency Regulation Reserve and Contingency Reserve dispatched by the System Operator or under contract.

Fast Start. - The capability of a generating unit or generating plant to start and synchronize with the Grid within 15 minutes.

Free Governor Mode (FGM) – A generating unit operating under the control of a governor which has been calibrated to control the output of the generating unit in accordance with set levels of frequency, voltage or other parameter, without the need for external control signals.

Frequency Control – A strategy used by the System Operator to maintain the Frequency of the Power System within the limits prescribed by the Grid Code by the timely use of Frequency Regulation Reserve, Contingency Reserve, and Demand Control.

Generator - any person or entity authorized by the ERC to operate a facility used in the generation of electricity.

Good Industry Practice. The practices and methods not specified in specific standards but generally accepted by the power industry to be sound and which ensure the safe and reliable planning, operation, and maintenance of a Power System.

Grid – The high voltage backbone system of interconnected transmission lines, substations and related facilities for the purpose of conveying bulk electricity. Also referred to as the transmission system.

Grid Code - The set of rules, requirements, procedures, and standards to ensure the safe, reliable, secured and efficient operation, maintenance, and development of the high voltage backbone Transmission System and its related facilities, as promulgated and approved by the ERC.

Market Operator – An independent group, with equitable representation from the electric power industry participants, whose task includes the operation and administration of the WESM in accordance with the WESM Rules, and development of the dispatch schedule that is submitted to the System Operator.

(MVAR) - Mega Volt-Ampere Reactive

National Grid Corporation of the Philippines (NGCP) – The Concessionaire for the Philippines Grid, as provided for under R.A.9511, with an exclusive national franchise for the operation, maintenance and expansion of the Grid.

OATS Rules: - Rules Terms and Conditions for the Provision of Open Access Transmission Services, as revised by the ERC from time to time.

Power Factor. - The ratio of Active Power to Apparent Power.

Power System: - As defined in the Grid Code.

Qualified Generating Unit – A generating unit which has been tested and certified as qualified by the System Operator under the provisions of this ASPP document (refer section 4.3).

Qualified Generator – A generator which has one or more, Qualified Generating Unit(s) which have been tested and certified as qualified under the provisions of this ASPP document (refer section 4.3), where only the Qualified Generating Units are eligible to be scheduled as and receive payments for providing Ancillary Services.

Qualified Interruptible Load – A load which has been tested and certified as qualified by the System Operator under the provisions of this ASPP document (refer section 4.3), where only the Qualified Interruptible Loads are eligible to be scheduled as and receive payments for providing Ancillary Services.

Reactive Capability Curve – Refer to Attachment 6 for an example.

Regular Energy Supply – Is defined as the output of energy by a generator at a given Active Power level and over a given time interval under the Dispatch Instructions of the System Operator.

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.

Reactive Power Support – As defined in clause 3.1.4.

Regulating Reserve (FRR) – As defined in the WESM Rules. A more detailed explanation is provided in clause 3.1.1.

Reserves PCRM – The pricing and cost recovery mechanism for reserves in the Philippine Wholesale Electricity Spot Market

Sufficient Reserve Capacity - Is defined as an excess of generation capacity over current demand within a Grid of greater than 10%. Such reserve capacity shall be assessed by the SO in conjunction with the MO on a quarterly basis, and be reported in writing to the ERC.

System Operator - The section within the Transmission Provider's organization responsible for generation dispatch, or the implementation of the generation dispatch schedule of the Market Operator, the scheduling and dispatch of Ancillary Services, and operation to ensure the safety, power quality, stability, reliability and security of the Grid.

TransCo – The National Transmission Corporation of the Philippines, which is currently the owner of the electricity transmission assets of the Philippines Grid.

Transmission Provider: - The Concessionaire with the exclusive national franchise for the operation, maintenance and expansion of the Grid, as provided for in RA 9511. For the avoidance of doubt, the Transmission Provider includes the System Operator.

Under Frequency Relays (UFR) – A relay which monitors frequency within a calibrated band and which can disconnect a load automatically where it measures a frequency lower than the value set as the lower trigger point.

WESM – Philippines Wholesale Electricity Spot Market

Where terms are not defined in this ASPP reference should be made to the EPIRA, IRR, Grid Code or WESM Rules.

1.3 Scope and Applicability

This document is an extension of, and should be read in conjunction with, the OATS Rules. It covers the definition of the types of Ancillary Services, the level of Ancillary Services required to be provided by the Transmission Provider, the processes to certify Qualified Generating Units and Qualified Interruptible Loads which the Transmission Provider can contract and/or schedule for provision of Ancillary Services, and the processes for monitoring Ancillary Services Providers to control performance and the obligation for payments.

The cost recovery mechanism for the provision of scheduled Ancillary Services is defined in the Ancillary Services Cost Recovery Mechanism (AS-CRM), which is a separate document subject to due process and approval by the ERC.

2.0 Effectivity

The ASPP as amended shall take effect upon the date of the approval of the amendments by the ERC.

3.0 Grid Ancillary Service Requirements

3.1 Specification of Ancillary Services

The following Ancillary Services will be procured from various Qualified Generators and Qualified Interruptible Loads. These Ancillary Services are essential in maintaining power quality, reliability, and security of the Philippine Power System.

3.1.1 ***Regulating Reserve Service*** - Also called load following and frequency regulating reserve; is generating capacity that is allocated exclusively to cover inter- and intra-hour variations in demand (load behaviors), variations from generation schedules and hourly forecasts. During normal system conditions, loads and generator outputs vary from time to time; this behavior results in imbalance between supply and demand characterized by small deviations in system frequency. The Philippines Grid Code (PGC) requires that under normal conditions the frequency should remain within +/- 0.6 Hz of the standard 60.0 Hz in order to ensure quality of supply and security of the Grid. As a general rule, only generators that are not fully loaded and operating under Free Governor Mode (FGM) and those with Automatic Generation Control (AGC) interfaced with the Energy Management System (EMS) of the Transmission Provider will be qualified to provide this kind of Ancillary Service.

3.1.2 ***Contingency Reserve Service*** – Synchronized generation capacity from Qualified Generating Units and Qualified Interruptible Loads allocated to cover the loss or failure of a synchronized generating unit or a transmission line or the power import from a single circuit interconnection, whichever is larger. In order to maintain the balance between generation and load on a real time basis, there must be capacity allocated and

immediately available whenever the total supply or generation in the Grid is reduced due to tripping of a generating unit or loss of a transmission line link or loss of a single circuit interconnection. Generators that are not fully loaded and operating under Free Governor Mode (FGM) or that can increase their active power output under manual control in response to a Dispatch Instruction from the System Operator can be qualified to provide this Service. Interruptible Loads that can be dropped automatically by means of Under Frequency Relays (UFR) can also provide this type of Ancillary Service.

3.1.3 ***Dispatchable Reserve Service*** – This is generating capacity that is not scheduled for Regular Energy Supply, Regulating Reserve or Contingency Reserve, or interruptible loads not scheduled for Contingency Reserve, and that are readily available for dispatch in order to replenish the Contingency Reserve Service whenever a generating unit trips or a loss of a single transmission interconnection occurs. This type of Ancillary Service can be provided by Qualified Generators that are not connected to the Grid but have fast start capabilities and can ramp up their output up the offered Dispatchable Reserve within thirty minutes. Generators that are already connected to the Grid and have Excess Capacities beyond their Regular Energy Supply, Regulating Reserve and Contingency Reserve capacities can also be considered to provide this type of service, provided that they can fully deliver their offered reserve capacities within thirty minutes. Likewise, interruptible loads that can be dropped within thirty minutes upon receipt of the Dispatch Instructions can also qualify to provide this service.

3.1.4 ***Reactive Power Support Service*** - is the capability of a generating unit to supply Reactive Power to, or absorb Reactive Power from, the Grid in order to maintain the bus voltage within five percent (5%) of its nominal voltage. A generator is considered to be providing Reactive Power Support if it operates outside the range of 0.85 lagging and 0.90 leading Power Factor but within its Reactive Capability Curve. Refer to Attachment 6 for a typical Reactive Capability Curve.

3.1.5 ***Black Start Service*** - The need for this Ancillary Service arises when an event or significant incident will result in a partial or total system blackout. This is the ability of a generating unit, without assistance from the Grid or other external power supply, to recover from a shutdown condition to an operating condition in order to energize the Grid and assist other generating units to start. Black Start plants must be able to be put on-line and ready to extend power within thirty (30) minutes upon receipt of a

dispatch instruction and must be capable of sustained operation for at least 12 hours.

3.2 Technical Requirements

This section sets out the arrangements the Transmission Provider will follow for contracting each category of Ancillary Services. On the other hand, a contracted Ancillary Service Provider shall use reasonable efforts, in accordance with Good Industry Practice, to ensure that plant and equipment providing Ancillary Services meet the relevant technical specifications of the Grid Code .

3.2.1 *Regulating Reserve Service*

Regulating Reserve provides the generating capacity necessary to adjust total system generation over short periods of time to match random fluctuations in total transmission system load through both upward and downward adjustments of generation Active Power output. The objective of purchasing Regulating Reserve is to control the Power System frequency to within the specified limits of 59.4 Hz to 60.6 Hz in accordance with Section 3.2.2.2 of the Grid Code. However, the System Operator is required to use the Regulating Reserve to control the system frequency within a +/- 0.3 Hz range of 60.0 Hz to ensure that the limits set by the Grid Code will not be violated during normal Power System conditions.

3.2.1.1 *Operating characteristics and technical capabilities of generating units providing Regulating Reserve:*

3.2.1.1.1. Generating units providing Regulating Reserve must be capable of contributing to Frequency Control by continuous regulation of the Active Power supplied to the Grid throughout the duration of the Dispatch Period over which they are scheduled to provide the service.

3.2.1.1.2 Generating units providing Regulating Reserve must be capable of operating under the AGC of the Transmission Provider's EMS. Only generating units with AGC capabilities or those capable of operating in Free Governor Mode will be qualified to provide this service. However, manual adjustment of Active Power output in accordance with specific Dispatch Instructions from the System Operator that mimic the

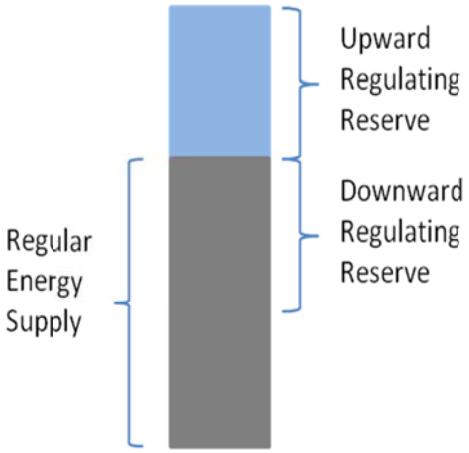
capabilities of the AGC will be allowed where the AGC function of the EMS is not fully operational. The maximum response time for the change in the generating unit's Active Power output shall be twenty-five (25) seconds and the new Active Power output shall be sustainable for at least thirty (30) minutes.

3.2.1.1.3 The governing system of generating units providing Regulating Reserve must be capable of accepting raise and lower signals or set point signals from the Transmission Provider's EMS and/or operating in a frequency sensitive mode such as Free Governor Mode.

3.2.1.1.4 A Generator providing Regulating Reserve must be synchronized and, with a Power System Frequency of 60 Hz, be operating with an Active Power output that will allow it raise or lower its Active Power output by the dispatched Regulating Reserve Capacity and remain within its rated Active Power output range.

3.2.1.1.5 The capacity offered for this Ancillary Service should not be used for Regular Energy Supply. As an illustration, Figure 3.2.1 below shows the relationship between Regulating Reserve and Regular Energy Supply:

Figure 3.2.1 : Regulating Reserve



3.2.2 ***Contingency Reserve Service***

The purpose of this Ancillary Service is to immediately arrest the Power System frequency decay as a result of an unplanned tripping of a generating unit or a transmission line or the unplanned loss of the power import from a single circuit interconnection or unscheduled reduction in generation output or unexpected large increase in load. This type of service can be provided by Qualified Generating Units and Qualified Interruptible Loads. Utilization of Contingency Reserve should be triggered when the Power System frequency drops to 59.7Hz.

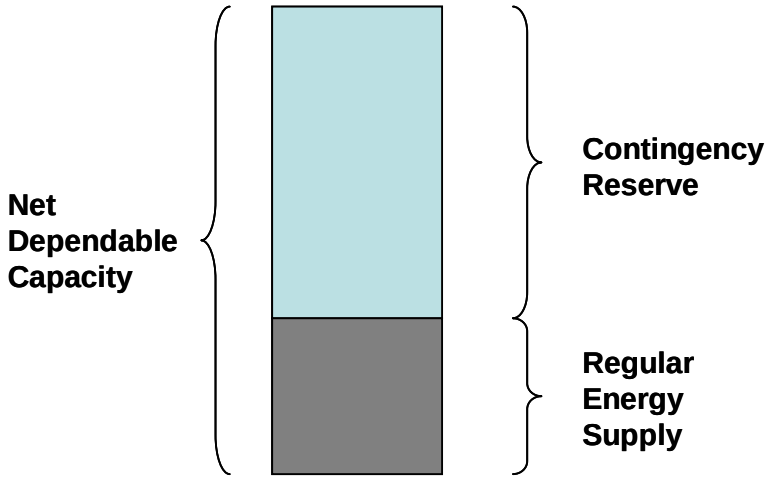
3.2.2.1 *Operating characteristics and technical capabilities of generating* u*nits providing Contingency Reserve:*

3.2.2.1.1 A generating unit providing Contingency Reserve Ancillary Service must be synchronized with the Grid with active power output capacity that can immediately be used in response to a sudden drop of Power System frequency. Generating units providing this service should be operating in Free Governor Mode or frequency sensitive mode otherwise known as primary control mode. Alternatively they must be able to increase their active power output under manual control following receipt of a Dispatch Instruction from the System Operator.

3.2.2.1.2 Generating units operating in providing Contingency Reserve Ancillary Service should have a governor speed droop setting of five (5) per cent. Generating units should be able to attain its reserve capacity within ten (10) minutes and the reserve capacity must be sustainable for a period of at least thirty (30) minutes.

3.2.2.1.3 The capacity of generating units offered for this Ancillary Service should not be used for Regular Energy Supply. As an illustration, Figure 3.2.2 below shows the relationship between Contingency Reserve and Regular Energy Supply:

Figure 3.2.2 : Contingency Reserve



3.2.2.2 *Operating characteristics and technical capabilities of Interruptible Loads providing Contingency Reserve:*

3.2.2.2.1 An interruptible load providing Contingency Reserve as an Ancillary Service must be connected to the Grid with committed load that can automatically be dropped in response to sudden decay of Power System frequency. Loads providing this service must be controlled by Under Frequency Relays that can disconnect the load once the desired tripping frequency is reached without any time delay.

3.2.2.2.2 An interruptible load providing Contingency Reserve must have the capability of providing real time data (Active Power readings and status of load controlling equipment) to the Transmission Provider's EMS.

3.2.2.2.3 An interruptible load providing Contingency Reserve as an Ancillary Service must be able to provide a committed uniform load reduction throughout the Dispatch Period for which it is scheduled to provide the service. The committed load reduction must be able to stay interrupted for at least thirty (30) minutes.

3.2.3 ***Dispatchable Reserve Service***

The purpose of Dispatchable Reserve is to replenish Contingency Reserve. This Ancillary Service can be provided by generating units whether synchronized or not and also by interruptible loads.

3.2.3.1 *Operating characteristics and technical capabilities of generating units providing Dispatchable Reserve:*

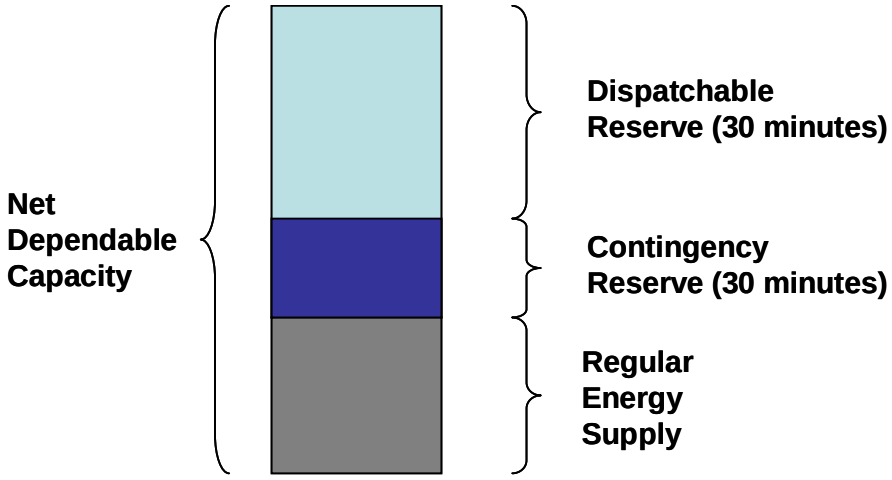
3.2.3.1.1 Unsynchronized generating units providing Dispatchable Reserve shall have a Fast Start capability and must be able to synchronize to the Grid within fifteen (15) minutes and load up to their offered reserve capacity within a further fifteen (15) minutes, or a total of thirty (30) minutes from receipt of a dispatch instruction.

3.2.3.1.2 Synchronized generating units providing Dispatchable Reserve should have available capacity that can be loaded up to its offered reserve capacity within thirty (30) minutes of receipt of a Dispatch Instruction.

3.2.3.1.3 Generating units providing Dispatchable Reserve whether synchronized or not should be able to sustain their operation for a minimum of eight (8) hours.

3.2.3.1.4 The capacity of a generating unit offered for this Ancillary Service should not be part of the Regular Energy Supply. As an illustration, Figure 3.2.3 below shows the relationship between Contingency Reserve, Dispatchable Reserve and Regular Energy Supply of a generating unit already supplying energy.

Figure 3.2.3: Dispatchable Reserve



3.2.3.2 *Operating characteristics and technical capabilities of interruptible loads providing Dispatchable Reserve:*

3.2.3.2.1 Interruptible loads providing Dispatchable Reserve must be able to drop their committed loads within thirty (30) minutes upon receipt of a Dispatch Instruction from the System Operator.

3.2.3.2.2 Interruptible loads providing Dispatchable Reserve must have the capability of providing real time data (Active Power readings and status of load control equipment) to the Transmission Provider's EMS.

3.2.3.2.3 Interruptible Load providing Dispatchable Reserve should be able to provide a committed uniform load throughout the Dispatch Period. Interruptible Loads should also be able to remain disconnected until ordered by the System Operator to reconnect to the Grid.

3.2.4 ***Reactive Power Support Service***

The purpose of Reactive Power Support is to supplement other Reactive Power sources connected the Grid, and to contribute to network voltage control.

3.2.4.1 *Operating characteristics and technical capabilities of Generating Units providing Reactive Power Support:*

3.2.4.1.1 In accordance with clause 4.4.2.3 of the Grid Code, all generating units supplying energy to the Grid shall be capable of supplying their Active Power output, as specified in the Generator's declared data, within the limits of 0.85 Power Factor lagging and 0.90 Power Factor leading at the generating unit's terminals, in accordance with its Reactive Capability Curve (Refer to Attachments 3 and 6).

3.2.4.1.2 Beyond these required limits for the lagging and leading Power Factor, a generating unit can supply additional Reactive Power to the Power System, if the Power System so requires through Reactive Power dispatch as a good utility practice. Alternatively it may offer Reactive Power Support as an Ancillary Service, subject to dispatch by the System Operator when required.

3.2.4.1.3 Reactive Power generation shall be limited only to the boundaries of the Reactive Capability Curve of the generating units.

3.2.5 ***Black Start Service***

The objective of the Black Start Ancillary Service is to energize a section of the Grid without the use of external power sources, allowing further connection of transmission circuits, and demand to be progressively connected, until the network is re-integrated.

3.2.5.1 Operating characteristics and technical capabilities of generating units providing Black Start Ancillary Service:

3.2.5.1.1 The Grid shall have Black Start capability at a number of strategically located generating plants.

3.2.5.1.2 Sufficient Black Start and Fast Start capacity shall be available at strategic locations to facilitate the restoration of the Grid to its normal state following a total Power System blackout and available at all

times to facilitate the goal of a complete system restoration in twelve (12) hours.

3.2.5.1.3 Redundancy of Black Start generation shall be taken into consideration due to possibility of a generating unit's failure to start or transmission facility failures preventing generating units from serving their intended loads.

3.2.5.1.4 Planned maintenance of generating units at a plant providing Black Start Ancillary Service shall not reduce the available black start capacity at the plant to below its contracted level.

3.2.5.2 When a generating unit becomes isolated from the Grid, its governing system may be requested to provide Frequency Control to the resulting island Grid. Generators shall provide this service when requested by the System Operator, where the generating unit has the necessary capability.

3.2.5.3 There shall be at least 50 MW of Black Start Ancillary Service capability available per restoration highway in Luzon, 20 MW for Visayas and 25 MW for Mindanao. However, the maximum Black Start Ancillary Service capability shall be determined by the System Operator, subject to confirmation by the Grid Management Committee prior to the beginning of each financial year, taking into account technical requirements and financial considerations.

3.3 Required Levels of Ancillary Services

3.3.1 *Regulating Reserve Service (FRR)*

The System Operator shall allocate $\%FR_G$ of system demand for each hour (corresponding to a WESM trading interval) as the minimum requirement for Luzon, Visayas and Mindanao Grids in accordance with the requirements below:

The level of Regulating Reserve Ancillary Service can be computed as follows:

$$FRR^{h}_{G} = F^{h}_{DG} \times \%FR_G$$

Where:

FRR^{h}_{G}	=	Regulating Reserve of Grid "G" for trading interval "h"
F^{h}_{DG}	=	Forecast Demand of Grid "G" for trading interval "h"
$\%FR_{G}$	=	Minimum percent Frequency Regulating Reserve requirement of the Grid "G", as approved by the ERC, after consultation and due process
$\%FR_{L}$	=	Currently set to 4.0% for Luzon
$\%FR_{V}$	=	Currently set to 4.0% for Visayas
$\%FR_{M}$	=	Currently set to 4.0% for Mindanao

3.3.2 ***Contingency Reserve Service (CR)***

The Contingency Reserve Ancillary Service level shall be computed on an hourly basis (corresponding to a WESM trading interval) and shall be the sum of the load of the largest generating unit connected to the Grid and the scheduled Regulating Reserve level, if any, of that generating unit for the trading interval. Not more than thirty (30) per cent of the required Contingency Reserve Ancillary Service shall be allocated to Interruptible Loads during periods where Sufficient Reserve Capacities are available from generators. Where there is not Sufficient Reserve Capacity, the System Operator is responsible for determining the level of Contingency Reserve Ancillary Service sourced from Interruptible Loads, including levels above thirty (30) percent, bearing in mind the additional costs which this imposes on consumers.

The level of Contingency Reserve on can be computed as follows:

$$CR^{h}_{i\,G} = \text{Max}\,(GL^{h}_{i} + GR^{h}_{i})_{G}$$

Where:

CR^{h}_{i}	=	Contingency Reserve of generating unit "i" for trading interval "h" of Grid "G"
GL^{h}_{i}	=	Scheduled unit load of generating unit "i" for trading interval "h" of Grid "G"
GR^{h}_{i}	=	Scheduled Regulating Reserve level of generating unit "i" for trading interval "h" of Grid "G"

i	=	from 1 to total number of generating units on line for trading interval "h" within Grid "G"
G	=	respectively Luzon, Visayas and Mindanao

3.3.3 ***Dispatchable Reserve Service (DR)***

There must be sufficient Dispatchable Reserve in each Grid at any given time to reinstate the Contingency Reserve to its required minimum level after thirty (30) minutes of an event occurring that fully utilizes the Contingency Reserve currently available for dispatch. This will be achieved if the available Dispatchable Reserve is equal to the scheduled Active Power output and Regulating Reserve of the second largest generating unit connected online in an hourly trading interval. Not more than fifty (50) per cent of Dispatchable Reserve shall be allocated to Interruptible Loads during periods where Sufficient Reserve Capacities are available from generators. Where there is not Sufficient Reserve Capacity, the System Operator is responsible for determining the level of Dispatchable Reserve sourced from Interruptible Loads, including levels above fifty (50) percent, bearing in mind the additional costs which this imposes on consumers.

The level of Dispatchable Reserve on the hourly basis for a particular Grid can be computed as follows:

$$DR^{h} = CR_{min}^{h}$$

Where:

CR_{min}^{h} = Minimum level of Contingency Reserve in hour "h", in a particular Grid.

3.3.4 ***Reactive Power Support Service (RS)***

The required level of Reactive Power Support Ancillary Service is dependent on the Power System condition. Reactive Power Support from generators is at maximum during peak and off-peak periods. During peak periods, generators are made to operate at lagging Power Factor to produce Reactive Power, while on off-peak periods, some generators may be required to operate in leading power factor to absorb Reactive Power. As such, the Reactive Power requirement of the Power System can only be determined once the day ahead dispatch schedule of the generators is available. In determining the required Reactive Power Support Ancillary

Service for the Power System, the System Operator should use a power system simulator (utilizing load flow software).

3.3.5 ***Black Start Service(BS)***

3.3.5.1 Black Start service shall be contracted to Qualified Generators based on the requirement that there should be at least two (2) plants contracted per power restoration highway and one (1) should always be available at any given time.

3.3.5.2 In Luzon, there are five (5) main sub-grids, four (4) of which are allocated to the Area Control Centers (ACC) and one (1) to Metro Manila. For each sub-grid there are at last two (2) restoration highways. In Mindanao, there are five (5) ACC, and each ACC is equipped with one (1) restoration highway. Further, the Visayas Grid also has five (5) ACC, that are each equipped with one restoration highway.

4.0 Procurement of Required Ancillary Services

For the sake of clarity, where Ancillary Services have been scheduled and dispatched by the System Operator, but are unable to be provided for whatever reason by the Qualified Generating Unit or Qualified Interruptible Load, then no payments shall be made in respect of those Ancillary Services that have been dispatched and not provided.

4.1 Methods of Procurement of Ancillary Services

4.1.1 To ensure that there is sufficient Ancillary Services available in the Grid at any given time, the Transmission Provider has sought approval from the ERC to modify its approach to acquiring these services. There will now be three methods of procuring Ancillary Services. The method to be used shall be approved by the ERC. Only one method shall be used in a particular Grid at any one time. These three methods are listed below.

4.1.1.1 Procurement by the Transmission Provider through the existing bilateral contract approach where contracts are negotiated directly with Ancillary Service Providers and approved by the ERC. This shall be replaced by one of the following approaches once approved by the ERC.

4.1.1.2 Procurement by the Transmission Provider through a competitive tendering or alternative procurement approach with similar objectives, which shall in turn be replaced by the following approach once approved by the ERC.

4.1.1.3 Procurement by the System Operator on behalf of the Market Operator using one of the methods specified in clause 3.3.3.3 of the WESM Rules once the ERC approves the Reserves PCRM and the reserves market for a particular Ancillary Service on a particular Grid has been declared commercial by the Department of Energy.

4.1.2 Until such time that the ERC approves the operation of the either a competitive tendering or alternative procurement approach with similar objectives, or the WESM reserves market, the Transmission Provider must source Ancillary Services in a manner that seeks to minimize the cost of Ancillary Services by Grid, and that does not favor one Qualified Generating Unit or Qualified Interruptible Load over another, subject to the overriding objective of ensuring the safety and security of the Power System.

4.1.3 A competitive tendering or alternative procurement approach with similar objectives shall be utilized by the Transmission Provider for the procurement of the required Ancillary Services for each of the Luzon, Mindanao and Visayas Grids once it has been approved by the ERC. The Transmission Provider shall submit to the ERC the design and rules of a competitive tendering or alternative procurement approach that shall form part of this ASPP once approved. The scheduling, dispatch, pricing, payment to Ancillary Services Providers and cost recovery of Ancillary Services procured under the competitive tendering or alternative procurement approach shall be covered in the design and rules.

4.1.4 The Reserves PCRM, or other process meeting the cost recovery requirements of section 3.3.5 of the WESM Rules and the objectives of section 3.3.4 of the WESM Rules for a WESM reserves market, shall be utilized in procurement of the required Ancillary Services for each of the Luzon, Mindanao and Visayas Grids once the Reserves PCRM has been approved by the ERC and the establishment of the relevant WESM reserves market has been approved by the Department of Energy. The Market Operator will submit to the ERC the Reserves PCRM design and rules that shall form part of this ASPP once approved. The scheduling, dispatch, pricing, payment to Ancillary Service Providers and cost

recovery of Ancillary Services procured under the Reserves PCRM are covered in the Reserves PCRM design and rules.

4.1.5 The ERC may approve different procurement methods for different Grids and also for different types of Ancillary Service.

4.2 Methods of Scheduling and Dispatch of Ancillary Services

4.2.1 To ensure that there are sufficient Ancillary Services available in the Grid at any given time, the Transmission Provider has sought approval from the ERC to modify its approach to scheduling and dispatching these services. There will now be three methods of scheduling and dispatching Ancillary Services. Only one method shall be used in a particular Grid at any one time. These three methods are listed below.

4.2.1.1 The existing approach used by the Transmission Provider as outlined in section 4.2.2 below. This shall be replaced by one of the following approaches once approved by the ERC.

4.2.1.2 The approach outlined in the design and rules of a competitive tendering, or alternative procurement approach with similar objectives approved by the ERC, which shall be replaced by the following approach once it is approved by the ERC.

4.2.1.3 The WESM once the ERC approves the WESM reserves market through the Reserves PCRM. Under the WESM the dispatch of energy and reserves will be integrated using the market dispatch optimization model to co-optimize the total cost of energy and reserves.

The approach approved by the ERC may differ from Grid to Grid and also for different types of Ancillary Service. The following sections provide more detail on these approaches used to schedule and dispatch Ancillary Services.

4.2.2 **Pre-WESM and Non-Tradable Ancillary Services**

Ancillary Service Providers must use reasonable endeavours to ensure that the contracted plants are available to be dispatched to provide the Ancillary Services. The Ancillary Service dispatch protocol described in this Section has been developed to guide Ancillary Service Providers and the System Operator in the scheduling and dispatch of Ancillary Services. This protocol shall remain in effect following implementation of the Reserves PCRM regime but will then be only applicable those Ancillary

Services for which procurement under WESM has not been approved by the ERC.

4.2.2.1 **Non Tradeable Ancillary Services Dispatch Protocol**

4.2.2.1.1 Ancillary Service providers shall submit daily to the System Operator on or before 1400H of the day preceding the dispatch day the following data:

- Hourly day ahead capacity nomination;
- Status of Black Start equipment (for Black Start Ancillary Service Providers); and
- Hourly day ahead capacity nominations for Ancillary Service Providers providing Regulating Reserve, Contingency Reserve, Dispatchable Reserve, Reactive Power Support and Black Start Ancillary Services.

4.2.2.1.2 The System Operator shall prepare the hourly reserve requirement based on the load forecast for the following day.

4.2.2.1.3 The System Operator shall prepare and issue to Ancillary Service Providers on or before 1600H the hourly day ahead schedule for Regulating Reserve, Contingency Reserve, Dispatchable Reserve, Reactive Power Support and Black Start services for all Ancillary Service Providers that are required to be available the following day. This Ancillary Service day ahead schedule shall be based on the following:

- Hourly reserve requirement;
- Ancillary Service capacity nomination;
- Merit order table of each Ancillary Service;
- Available Black Start units; and
- Reactive Power Support Requirement of the Power System.

4.2.2.1.4 The System Operator shall dispatch all plants for Ancillary Services according to the approved Ancillary Services day ahead schedule. In the

event of the following conditions, the System Operator may undertake re-dispatch procedures:

- Outage of transmission lines or substation facilities;
- Violation of Power System security limits;
- Total Power System failure;
- Unexpected reduction of generation availability;
- Force majeure events; or
- Emergency security measures.

4.2.2.1.5 Ancillary Service Providers shall implement the System Operator's dispatch instructions and ensure that the required Ancillary Services are provided.

4.2.2.1.6 The System Operator shall monitor the compliance of Ancillary Services Providers based on the approved Ancillary Services Provider schedule using the EMS system and available meter data.

4.2.2.1.7 The System Operator shall prepare a statement of compliance for each showing the Ancillary Services dispatched for each Dispatch Period and indicating the extent to which the Ancillary Services Provider complied with the Dispatch Instructions. This will be forwarded to the Transmission Provider for the preparation of settlement statements for each Ancillary Services Provider.

4.2.2.1.8 Ancillary Service Providers must receive, evaluate and validate the submitted settlement statements prepared by the System Operator and return it to the Transmission Provider for billing settlement in accordance with the relevant Ancillary Services Agreement.

4.2.2.1.9 The Transmission Provider shall recover the costs of providing the Ancillary Services in accordance with the Ancillary Services Cost Recovery Mechanism (AS-CRM) approved by the ERC.

4.2.2.1.10 The Transmission Provider shall submit a monthly report on Ancillary Services scheduling, and compliance to the ERC no later than the 15th day of the succeeding month. This report shall include full details of any re-dispatch procedures undertaken in accordance with the provisions of 4.2.2.1.4.

4.2.3 Tradable Ancillary Services under Competitive Tendering or Alternative Approach

In a competitive tendering regime, or an alternative approach with similar objectives, tradable Ancillary Services shall be dispatched in accordance with the relevant design and rules once these have been approved by the ERC following a public consultation process.

4.2.4 Tradable Ancillary Services under the WESM Regime

In the WESM regime, tradable Ancillary Services shall be dispatched in accordance with the WESM Rules and, once approved by the ERC, the Reserves PCRM design and rules shall be the governing document for Ancillary Services procurement, scheduling, dispatch and settlement. A summary of this approach is discussed in Section 4.2.4.1.

4.2.4.1 Overview of WESM Ancillary Services Procurement Process

When traded in the WESM, generation reserve Ancillary Services and Interruptible Loads must be offered and scheduled for dispatch for each trading interval. To facilitate this, qualified Ancillary Service Providers must submit generation reserve offers and Interruptible Load demand bids for each Dispatch Period within their designated Grids (i.e. Luzon, Visayas or Mindanao). The market management system is designed to accept different types of bids and offers other than energy. Each reserve offer shall have a maximum number of blocks per category of Ancillary Service (e.g. Regulating Reserve, Contingency Reserve or Dispatchable Reserve) in accordance with the WESM Rules

The Market Operator must accept and validate Ancillary Service offers in accordance with the accreditation and registration information of the qualified Ancillary Service Providers, as well as the current status of their generating or load facilities.

All valid Ancillary Service offers, including Interruptible Load demand bids will be scheduled and cleared in accordance with the forecast demand and the reliability requirements of the Grid. The reliability requirements determine the amount and types of Ancillary Services from Qualified Generators or Qualified Interruptible Loads needed for each Dispatch Period to meet the operating standards mandated by the Grid Code. The forecast demand derived from customer load projections serves as confirmation of the frequency regulation requirements of the System Operator. The optimal scheduling is performed using the market dispatch optimization model to simultaneously minimize the overall cost of energy and reserve in the WESM as the energy and reserve requirements are met.

The Ancillary Service allocations are submitted to the System Operator within the hourly dispatch schedules for actual dispatch implementation. Reserve prices and quantities which were cleared in the market are published through the WESM website for the information of the trading participants, Department of Energy (DOE), ERC and the general public.

During dispatch implementation, the System Operator will monitor the facilities of trading participants providing Ancillary Services to ensure compliance with the standards and to measure the actual quantity of Ancillary Service provided. The actual dispatch will be reported back to the Market Operator and then compared with the scheduled reserve allocation.

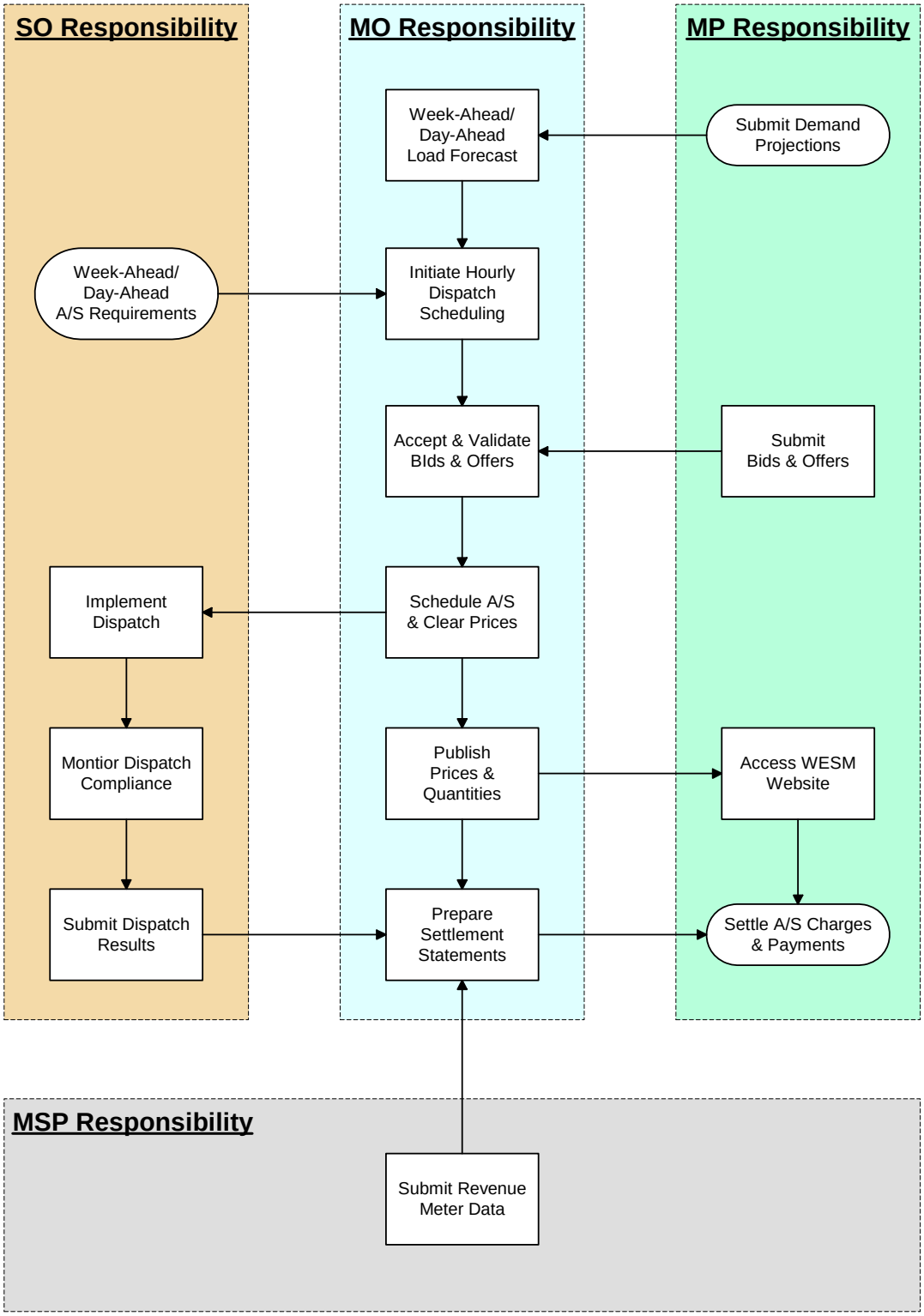
The Market Operator then prepares settlement statements for the payment and charging of Ancillary Services traded through the market on the basis of the scheduled and actual dispatch. These statements are provided to the concerned trading participants for their review, correction and final settlement. Note that, even prior to the issue of settlement statements, participants can access the WESM websites to immediately obtain information on the market clearing prices and quantities. This information is useful for reviewing the statement of accounts for possible correction.

Note also that the revenue meter data are used only for the allocation of Ancillary Service charges which, as proposed, will be based on the scheduled energy transaction of the participant

for the trading interval. This is to correct some misconceptions that revenue meters will be used to measure Ancillary Services such as reserves and Interruptible Loads.

Figure 1 below shows the process flow for the trading of Ancillary Services within the WESM as described in this section.

Figure 1. Ancillary Service Trading Process Flow



4.3 Qualification and Testing of Ancillary Service Providers

The Transmission Provider, as the System Operator, must use reasonable endeavors to procure Ancillary Services from Qualified Generating Units and Qualified Interruptible Load providers in order to maintain a sufficient level of Ancillary Services on the Grid. To qualify as providers of Ancillary Services all prospective providers should have undergone the certification process as defined in the Grid Code. If a provider has already been certified as a qualified Ancillary Services provider, an annual verification test will be conducted in order to ensure that the provider's capability to provide Ancillary Services is maintained.

The Transmission Provider is permitted by the Grid Code to conduct such tests no more than twice a year. Aside from the certification, the Transmission Provider requires that all qualified Ancillary Services providers should have a fully functional direct interface with the Transmission Provider's EMS. This means that relevant real time data such as; MW, MVAR, KV, circuit breaker or unit status and control of the Qualified Generating Units and Interruptible Loads are available at the System Operator's control centers. All Ancillary Services capability tests must be conducted by the prospective Ancillary Services Providers to provide evidence to the Transmission Provider of its ability to provide Ancillary Services. Upon evaluation of the test results, the Transmission Provider shall issue a certificate indicating the type and applicable capacity of Ancillary Services, and its validity. The following Ancillary Service capability tests will be conducted for all interested prospective providers:

4.3 1 *Regulating Reserve Capability Test*

4.3.1.1 Prospective Ancillary Service Providers shall prove to the Transmission Provider their capability to provide this service. This includes their ability to automatically adjust their generation output in response to system load changes and/or their ability to respond to AGC raise/lower or analog command signals (from the EMS of the System Operator) and also to attain their maximum reserve capacity within twenty-five (25) seconds and sustain the new Active Power output for at least thirty (30) minutes as specified in Section 3.2.1.1.2. Refer to the Ancillary Services Test and Measurement Procedures in Attachment 3, section 1.

4.3.2 *Contingency Reserve Capability Test*

4.3.2.1 Prospective Contingency Reserve Ancillary Service providers shall prove to the Transmission Provider their capability to provide this service. Generating units intending to provide this kind of service must demonstrate that their speed governing can respond to negative 0.15 Hz (-0.15 Hz) deviation and produce the nominated reserve within ten (10) minutes and sustain the nominated reserve for at least thirty (30) minutes. Generating units may at their own option demonstrate their ability to respond to AGC either raise/lower or analog command signals from the EMS of the System Operator. Refer to the Ancillary Services Test and Measurement Procedures in Attachment 3, section 2.

4.3.2.2 Likewise, Interruptible Loads intending to supply Contingency Reserve Ancillary Service shall prove that their nominated load can be automatically and instantaneously dropped to respond to negative 0.4 Hz (-0.4 Hz) frequency deviation and should not re-connect that load for at least thirty (30) minutes. Refer to the Ancillary Services Test and Measurement Procedures in Attachment 3, section 3.

4.3.3 ***Dispatchable Reserve Capability Test***

4.3.3.1 Prospective Ancillary Service providers shall demonstrate to the Transmission Provider their capability to provide this service. Generators with fast start capability intending to provide this Dispatchable Reserve Ancillary Service shall prove that their generating units can be started and synchronized to the Power System within fifteen (15) minutes and produce the nominated reserve within another fifteen (15) minutes and sustain their operation for at least eight (8) hours. Likewise, generating units that don't have fast start capability can only provide this kind of service if they are synchronized in the grid and must prove that they can produce the nominated capacity within thirty (30) minutes and sustain their operation for at least eight (8) hours. Generators may at their own option prove their ability to respond to AGC raise/lower or analog command signals EMS of the System Operator. Refer to the Ancillary Services Test and Measurement Procedures in Attachment 3, section 2.

4.3.3.2 Interruptible loads intending to supply Dispatchable Reserve Ancillary Service shall prove to the Transmission Provider that

their nominated load can be disconnected within thirty (30) minutes from receipt of an instruction from the System Operator and is not required to reconnect that load until instructed by the System Operator to do so. Refer to the Ancillary Services Test and Measurement Procedures in Attachment 3, section 3.

4.3.4 ***Reactive Power Support Capability Test***

4.3.4.1 Prospective Reactive Power Support Ancillary Service providers shall prove to the Transmission Provider their capability to provide this service. Generators intending to provide this kind of service should prove that their generating units can operate beyond the Grid Code required power factor range (85% PF lagging to 90% PF leading) to produce and absorb Reactive Power. Refer to the Ancillary Services Test and Measurement Procedures in Attachment 3, section 4.

4.3.5 ***Black Start Services Capability Test***

4.3.5.1 Prospective Black Start Ancillary Service providers shall prove to the Transmission Provider their capability to provide this service. Generating units must be able to start on their own within thirty (30) minutes following receipt of a Dispatch Instruction without any feedback power from the grid and should be able carry load and energize their assigned Blackout Restoration Highway and sustain its operations for at least twelve (12) hours. Refer to the Ancillary Services Test and Measurement Procedures in Attachment 3, section 5.

4.3.6 ***Failure of Capability Test & Re-Test Period***

4.3.6.1 Certified plants that fail in the annual verification test should endeavor to correct the deficiency as required in the Grid Code, less than sixty (60) days from the date of the failed test. Otherwise these plants may not be allowed to offer their Ancillary Service in that annual period.

4.3.6.2 Failure to rectify the reasons for failure of an annual verification test, within sixty (60) days of being requested in writing to do so by the System Operator will trigger the System Operator to report the failure to the ERC in writing, which may

lead to the imposition of appropriate penalties as approved by the ERC after consultation and due process.

4.3.6.3 After failure of an annual verification test, follow-up verification testing should be supported by the Transmission Provider on a date agreed with the Ancillary Service Provider. Such date should fall within sixty (60) days of the written request from the Transmission Provider to rectify the reasons for failure.

4.3.7 ***Testing of Ancillary Service Providers (ASP)***

4.3.7.1 All verification tests shall be recorded and witnessed by the authorized representatives of the Transmission Provider and the Ancillary Service Provider. The test procedures in Attachment 3 will be used for these tests. Failure to comply with this provision or the specified test procedures may render the verification tests void.

4.4 Monitoring of Ancillary Service Provision

4.4.1 Monitoring

The System Operator shall regularly monitor the performance of the Ancillary Service providers. The data from the Transmission Provider's EMS will be used in monitoring compliance with the required performance.

Ancillary Service Providers operating under AGC will be monitored using the alarm/event subsystem of the EMS. Occurrence of the "unit not tracking" event will be interpreted as failure to provide dispatched Ancillary Services.

Ancillary Service Providers operating in governor control mode will be monitored using data from the EMS. In particular, Power System frequency and generating unit Active Power output will be analyzed regularly and compared with the scheduled values for the particular services. Similarly, the actual Reactive Power output and substation voltage data from the /EMS will be analyzed and compared with the scheduled values.

The actual synchronization time of back-up and black start providers will also be monitored using the alarm/event subsystem of the EMS.

4.4.2 **Reporting & Capability Re-Test Trigger**

4.4.2.1 The System Operator shall provide a written exception report where the monitoring of an Ancillary Service Provider demonstrates a breach in its capability requirements on two consecutive monitoring instances. Such monitoring will occur at the discretion of the System Operator but should be a minimum of once per day, on two consecutive days, where an issue is identified.

4.4.2.2 Where a monitoring exception report is issued by the System Operator, the System Operator may require a re-test of the Ancillary Service Provider's capability to prove or disprove whether the provider can continue to be scheduled and paid for a particular Ancillary Service. The scheduling and payment for Ancillary Services to this provider will be suspended from the date of the issuance of the exception report, until the Ancillary Service Provider's capability is re-tested and re-certified in writing by the System Operator.

4.4.2.3 The Ancillary Services provider may request in writing to the System Operator a delay of no more that sixty (60) days before the re-test in order to rectify or replace any control or other equipment which has caused the capability failure.

4.4.2.5 Re-testing shall occur, on a date agreed between the System Operator and the Ancillary Service Provider in accordance with the provisions of section 4.3 of this ASPP. The scheduling and payment for Ancillary Services to this provider will only recommence once a successful capability test has been achieved, and the Ancillary Service has been successfully re-scheduled under the normal mechanism for scheduling specified elsewhere in the ASPP or related documents.

4.5 Payment to Ancillary Service Providers

4.5.1 Ancillary Service charges are treated differently from Power Delivery Service (PDS) charges and other transmission-related charges to the extent that they represent payment to Ancillary Service Providers for the provision of Ancillary Services which have been scheduled by the System Operator.

4.5.2 The Ancillary Services that will be paid for are: Regulating Reserve (FRR); Contingency Reserve (CR); Dispatchable Reserve (DR); Reactive Power Support (RS) and Black Start (BS) services. *Note: Under the WESM Rules other forms of Ancillary Services may be developed and then traded and settled in that market.*

4.5.3 The formulae for the payment and settlement to Ancillary Service Providers shall be specified in the applicable charging regime approved by the ERC for each Grid. Only one charging method shall be used in each Grid at any one time. These three different charging methods are described in the following sections.

4.5.3.1 The Ancillary Services Cost Recovery Mechanism approved by the ERC shall be used for the recovery and settlement of the costs of providing Ancillary Services until such time as it is replaced by one of the following approaches once approved by the ERC.

4.5.3.2 The arrangements specified in the design and rules of a competitive tendering regime or alternative approach with similar objectives, which has been approved by the ERC, shall be used for the recovery and settlement of the costs of providing Ancillary Services; which shall be replaced by the following approach once it is approved by the ERC.

4.5.3.3 The ERC approves the arrangements for the reserves market through the PCRM of the MO under the WESM Ancillary Services market for the clearing price and settlement arrangements.

5.0 Development of Other Forms of Ancillary Services

In addition to those Ancillary Services that have already been approved by the ERC, other forms of Ancillary Service are being considered for development in recognition of certain operational requirements of the System Operator and the MO. Among the new forms of Ancillary Services currently being studied are the following:

- Must-Run Capacity – this refers to certain generating units which are being required by the System Operator to run at certain power output levels for technical or other reasons.

- Constrained-Off Capacity – this refers to the ability of certain generating units to reduce their power output for system security reasons as determined by the System Operator.

Like all forms of Ancillary Services, commercial and technical terms must be established for each new category before they are filed with the ERC for approval. Among the necessary terms to be established are metrics, qualifying test and monitoring procedures, payment and cost recovery methods for ERC approval.

6.0 References

Unless otherwise amended and approved by the ERC, the following references are relevant to interpreting the terminology used in these ASPP.

1. Electric Power Industry Reform Act of 2001, (EPIRA), Republic Act No. 9136.
2. Philippine Grid Code, December 2001.
3. Philippine Distribution Code, December 2001.
4. Wholesale Electricity Spot Market (WESM) Rules, 2002.
5. Open Access Transmission Services (OATS) Rules, 2006 (or as reissued by the ERC).
6. Ancillary Services Cost Recovery Mechanism (ASCRM), September 2006.
7. Electronic Ancillary Services Design and Tendering (EAST), Draft dated December 2008.
8. Reserve Market Arrangements under Section 3.3 of the WESM Rules, administered by the Market Operator (MO) and the System Operator (SO).

Attachments

Attachment 1

Certification of Ancillary Service Providers

1.0 Purpose

1.1. This Attachment establishes guidelines to be followed the certification of Ancillary Service Providers who would like to provide Ancillary Services to ensure quality of power delivered through the Grid.

2.0 Scope

2.1. This Attachment covers only the certification process including contracting for Ancillary Service Providers.

3.0 Definition of Terms/Acronyms

3.1 **Definition of Terms**

3.1.1 **Ancillary Service Provider**- a person or entity providing Ancillary Services regardless of whether it is duly registered or not with the Market Operator, provided, however, that upon accreditation by the System Operator and prior to trading in the WESM, it shall register with the Market Operator.

3.1.2 **Ancillary Services**- As defined in the Grid Code and WESM Rules.

3.1.3 **Generator**- any person or entity authorized by the ERC to operate a facility used in the generation of electricity.

3.1.4 **System Operator**- the section within the Transmission Provider's organization responsible for generation dispatch, or the implementation of the generation dispatch schedule of the Market Operator, the scheduling and dispatch of of Ancillary Services, and operation to ensure the safety, power quality, stability, reliability, and the security of the Grid.

3.1.5 **Transmission Provider** - The Concessionaire with the exclusive national franchise for the operation, maintenance and expansion of the Grid, as provided for in RA 9511. For the avoidance of doubt, the Transmission Provider includes the System Operator.

3.2 **Acronyms**

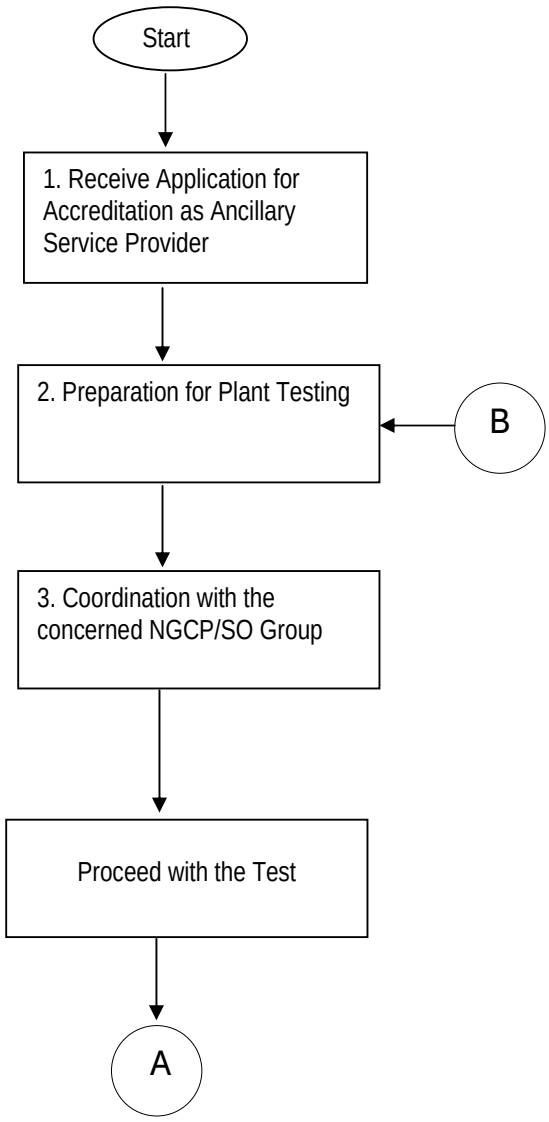
3.2.1 **ACC** - Area Control Center
3.2.2 **ASP** - Ancillary Service Provider
3.2.3 **A/S** - Ancillary Service

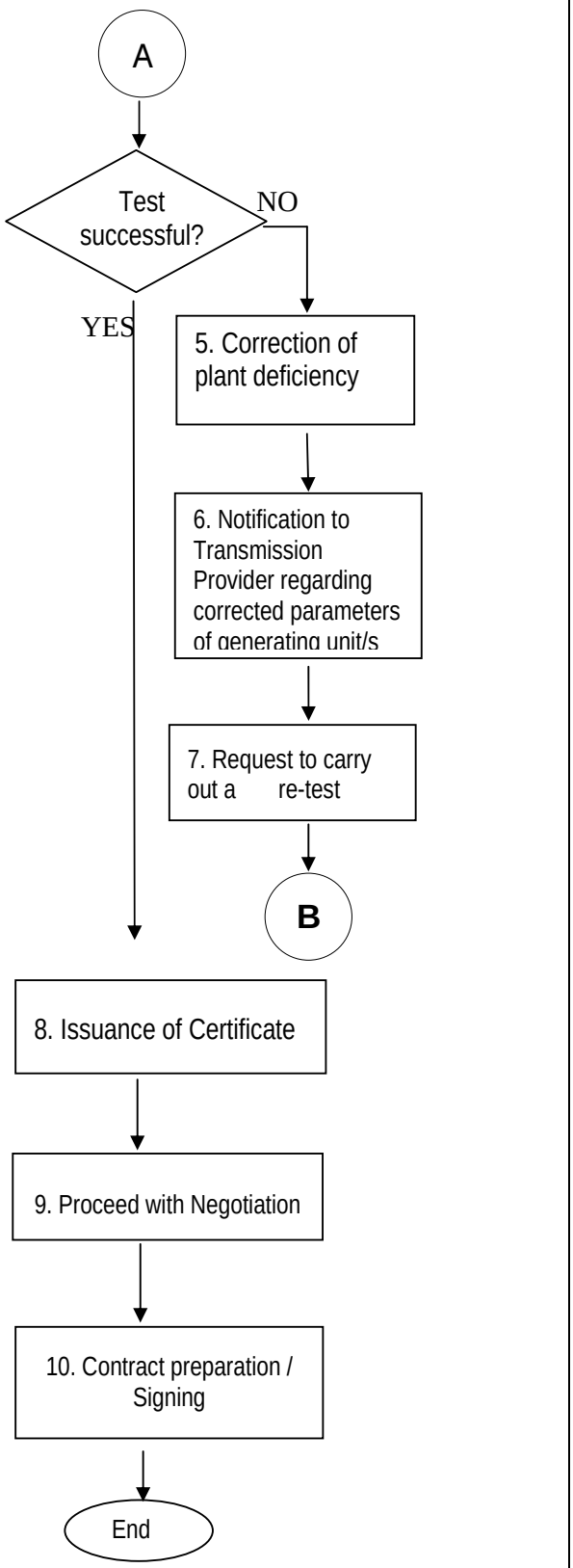
3.2.4 **NCC** - National Control Center
3.2.5 **OPD** - Operations Planning Division
3.2.6 **SCADA** - Supervisory Control and Data Acquisition
3.2.7 **SO** - System Operations or System Operator
3.2.8 **TransCo** - National Transmission Corporation
3.2.9 **NGCP** - National Grid Corporation of the Philippines, the concessionaire for Transco's assets.

4.0 References

4.1 Grid Code

5.0 Procedure

FLOWCHART	RESPONSIBILITY	DETAILS
	Transmission Provider Transmission Provider Transmission Provider Generator	1. The Transmission Provider, upon receipt of application for accreditation and required documents, will perform initial evaluation based on the technical requirements in Section 3.2 of this ASPP. 2. Notify and coordinate with the ASP regarding the test to be performed. Check the availability of test equipment and tools for testing. 3. Coordinate with NCC/ACC and OPD for the schedule of testing. 4. Conduct the test to be witnessed by the authorized representative of the Transmission Provider.

FLOWCHART	RESPONSIBILITY	DETAILS
	Generator Generator Transmission Provider Transmission Provider Transmission Provider Transmission Provider/Generator	5. Generator shall correct the deficiency of its generating unit/s within an agreed period to attain the relevant registered parameters for that unit/s. 6. The Generator shall immediately notify the Transmission Provider once the generating unit/s achieves the registered parameters. 7. Transmission Provider shall require the plant to conduct a retest in order to demonstrate that the appropriate parameter has already been restored to its registered value. 8. Issue Certification to ASP 9. Negotiate with ASPs regarding the details of the contract/agreement. 10. Prepare Memorandum of Agreement/Contract for signature of both parties concerned.

Attachment 2

Method of Determination of Ancillary Service Levels

1.0 Regulating Reserve

Several factors contribute to the fluctuations of Power System frequency over a short period of time. These are load forecast errors, load fluctuations, inability of some generating units to maintain steady output, and the mismatch between the rate of load change and the average ramp rates of the generating units.

In order to maintain the Power System frequency within the range of 59.85 - 60.15 Hz, there should be enough Regulating Reserve in the system. Intra-hour load variations, load forecast errors and the rate of load change are the biggest contributors of frequency fluctuations. Based on 2010 data the rate of load change is about 13.52 MW/min while the year-long average intra-hour load variation in Luzon is 7.32% of the hourly system demand. The biggest load in Luzon is the Kalayaan pump storage plant, which at normal operation; a single unit consumes steadily 165MW of power. Cyclic loads (e.g. steel mills) on Luzon and Mindanao grid have a significant effect on the Power System frequency, especially during off-peak periods when the system demand is low.

Based on the above, the minimum amount of Regulating Reserve can then be set at 4% of the forecast hourly system demand. The generating units that provide Regulating Reserve should have sufficient ramp rate to cover the rate of load change and load and generator output fluctuations. Generators with Automatic Generator Control (AGC) are the preferred providers of Regulating Reserve.

2.0 Contingency Reserve

In order to ensure reliability, adequacy, and security of the system, there must be enough Contingency Reserve synchronized to the Power System at any given time. Reliability can be described in terms of adequacy and security. Historically, utilities determine adequacy by means of probabilistic analysis and security by a deterministic method. Adequacy implies that there are sufficient generation and transmission resources available to meet projected needs plus reserves for contingency. On the other hand, security implies that

the system will remain intact even after outages or other equipment failures occur. In general, however, the required level of Contingency Reserve is currently based primarily on the magnitude of the largest single contingency (N-1 security criterion). The thinking behind this approach is that the system must be able to withstand such a contingency regardless of the probability of its occurrence. In other words, even if the largest generating unit has an excellent reliability record (e.g. less than one forced outage a year), the consequences of such an outage are so severe that the system must be protected against its occurrence. With the development of WESM, it is now accepted that provision of Contingency Reserve Ancillary Service can be managed by the System Operator through access to Qualified Interruptable Loads for load shedding and well as to Qualified Generating Units to provide additional power.

3.0 Dispatchable Reserve

Prior to the implementation of EPIRA, Power System planning engineers ensured that the Power System had ample Dispatachable Reserve to cover a certain level of loss of load probability (LOLP). The National Power Corporation then had set this level as 1 day LOLP or an equivalent of 30% of the peak demand as system planning reserve. Dispatchable Reserve was determined as the difference between system planning reserve and spinning reserve (30% less 10.4% or 19.6% of the system peak).

With the implementation of EPIRA, market forces now signal the need for additional investment for capacity and reserve. Hence, the Dispatchable Reserve margin should be set at a more optimum level.

The optimum level of Dispatchable Reserve at any given hour must be set equal to the minimum level of Contingency Reserve. The rationale of this is that not all reserve generators are capable of Fast Start and there should be enough Dispatchable Reserve to replace the Contingency Reserve that is used to respond to a Power System contingency. This minimum level of Dispatachable Reserve can be set as equal to the power output of the second largest generator online for the hour. It is also assumed that there is enough non-backup (cold or replacement) reserve within the 8-hour period to restore the Dispatchable Reserve to its minimum level.

Non-backup (cold or replacement) reserves are not treated as Ancillary Services as these generating units are the excess capacity that is not dispatched and are given ample time to start-up whenever needed by the Power System.

4.0 Reactive Power Support

The voltage throughout the Grid must be maintained within ±5% of nominal value as required by the Grid Code. The System Operator must control this voltage through the timely use of Reactive Power control devices (switched reactors and capacitors) and the purchase of additional Reactive Power (supply or absorption) from identified Generators.

The requirement for Reactive Power Support Ancillary Service varies according to the system load and condition. The required absorption and generation of Reactive Power can only be determined from the the day-ahead scheduling of dispatch. Generating units are the biggest suppliers/absorbers of Reactive Power. In order to encourage Generators to provide this service, they will be paid on the actual Reactive Power generation and/or absorption, outside the minimum Reactive Power generation and absorption capability specified in clause 4.4.2.3 of the Grid Code, in accordance with the scheduled Reactive Power as determined by the System Operator.

5.0 Black Start

The Transmission Provider is required to immediately restart the Grid after a total or partial system blackout. A number of power restoration highways are established to ensure this capability. The availability of Fast Start capacity with the need for an external power supply at strategic locations and redundancy of Black Start generation were taken into consideration in the design of the restoration highways. Hydro power plants and diesel power plants are typically used as Black Start plants.

Although a number of Power Restoration Highways have been established, a single main Power Restoration Highway has been defined for each regional control center. The remaining Power Restoration Highways are considered to be an alternative. Each of these main Power Restoration Highways must have at least two Black Start service providers.

Attachment 3

ANCILLARY SERVICE TESTING, CERTIFICATION AND ACCREDITATION

1.0 PURPOSE

To establish the guidelines to be used by NGCP for testing plant for certification to provide Ancillary Services; and for the Issue of Certification/Accreditation as an Ancillary Service Provider.

2.0 SCOPE

This procedure covers the testing and certification of Ancillary Services Providers for Regulating Reserve, Contingency Reserve, Dispatchable Reserve, Reactive Power Support and Black Start Ancillary Services as required by the Philippine Grid Code.

3.0 DEFINITIONS OF TERMS/ACRONYMS

3.1 Definition of Terms

3.1.1 **Ancillary Service Provider(s)** – person(s) or entity(ies) providing ancillary services regardless of whether they are duly registered or not with the Market Operator.

3.1.2 **Ancillary Services** – support services including Regulating Reserves, Contingency Reserves, Reactive Power Support, and Black Start capability which are necessary to maintain Power Quality and the Reliability and Security of the Grid.

3.1.3 **Automatic Generation Control (AGC)** – is 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.

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

3.1.5 **Contingency Reserve (CR)** – is a generating capacity from qualified generating units allocated to cover the loss of a synchronized

generating unit or power import from a single-circuit interconnection, whichever is larger.

3.1.6 **Contingency Reserve Service** – is a service that provides generating capacity necessary to respond immediately to infrequent, but usually large, failures of generating units and/or transmission tie lines.

3.1.7 **Control Center** – a facility used for monitoring and controlling the operation of the Grid, Distribution System, or a User System.

3.1.8 **Dispatch Instruction** – refers to the instruction issued by the System Operator to the generators with scheduled generating units and the generators whose generating units provide ancillary services to implement the final dispatch schedule in real time.

3.1.9 **Dispatchable Reserve -** is the generating capacity from qualified generating unit that are not scheduled for energy, regulating and contingency reserve in which they are readily available for dispatch to replenish the contingency reserve whenever a generating unit trips or a loss of single-circuit interconnection occurs.

3.1.10 **Frequency** – is the number of complete cycles of a sinusoidal current or voltage per unit time, usually measured in cycles per second or hertz.

3.1.11 **Frequency Control** – is a strategy used by the System Operator to maintain the frequency of the Grid within limits prescribed by the Grid Code by the timely use of Frequency Regulating Reserve, Contingency Reserve, and Demand Control.

3.1.12 **Generator** – is an entity authorized by the Energy Regulatory Commission to operate a facility used in the generation of electricity.

3.1.13 **Power Factor** – the ratio of Active Power to Apparent Power.

3.1.14 **Primary Response** – is the automatic response of a Generating unit to Frequency changes, released increasingly from zero to five seconds from the time of frequency change, and which is fully available for the next 25 seconds. The unit operates in a free governor mode at dead band setting within $\pm$ 0.15 Hz.

3.1.15 **Reactive Power** – the component of electrical power representing the alternating exchange of stored energy (inductive or capacitive) between sources and loads or between 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.

3.1.16 **Reactive Power Capability Curve** – a diagram which shows the reactive power capability limit versus the real power within which a generating unit is expected to operate under normal condition.

3.1.17 **Reactive Power Support -** the injection or absorption of reactive power from Generators to maintain Transmission System voltages within ranges prescribed in the code.

3.1.18 **Regulating Reserve (FRR)** – is the generating capacity from qualified generating units allocated to cover inter and intra-hour variations in demand (load behavior), variations from generation schedules and hourly forecasts.

3.1.19 **Regulating Reserve Service** – is a service that provides Generation Capacity necessary to adjust total system generation over short periods of time to match system load changes that result from random fluctuations in total transmission system load.

3.1.20 **Secondary Response** – is the automatic response to frequency change which is fully available 25 seconds from the time of frequency change to take over from the Primary Response, which is sustainable for at least 30 minutes.

3.1.21 **Toolbox Meeting -** a brief meeting done before the start of any activity to give everyone clarity about what needs to be done and why. It is also a way of dealing with any issues up front, and of improving teamwork through better (2-way) communication.

3.1.22 **Voltage** – the electromotive force or electric potential difference between two points which causes the flow of electric current in an electric circuit.

3.2 Acronyms

3.2.1 **ACC** – Area Control Center

3.2.2 **ACTO** – Assistant Chief Technical Officer

3.2.3 **AGC** – Automatic Generation Control

3.2.4 **ASP** – Ancillary Service Provider

3.2.5 **ASPP** – Ancillary Service Procurement Plan

3.2.6 **BS** – Black Start

3.2.7 **CR** – Contingency Reserve

3.2.8 **DR** – Dispatchable Reserve

3.2.9 **DGS** – Day-ahead Generation Schedule

3.2.10 **FR** – Frequency Regulation

3.2.11 **LSO** – Luzon System Operations

3.2.12 **MSO** – Mindanao System Operations

3.2.13 **MW** – Megawatt

3.2.14 **MVAR** – Mega Volt-Ampere Reactive

3.2.15 **MEX** – Maximum Excitation Level

3.2.16 **NOD** – Network Operations Division

3.2.17 **OPS** – Operations Planning Section

3.2.18 **PF** – Power Factor

3.2.19 **PQA** – Power Quality Analyzer

3.2.20 **PRH** – Power Restoration Highway

3.2.21 **RCC** – Regional Control Center

3.2.22 **RPS** – Reactive Power Support

3.2.23 **RR** – Regulating Reserve

3.2.24 **RSO** – Regional SO

3.2.25 **SCADA** – Supervisory Control and Data Acquisition

3.2.26 **SO** – System Operations

3.2.27 **VSO** – Visayas System Operations

4.0 GENERAL REQUIREMENTS

4.1 The Annual Ancillary Service Test Schedule is already approved.

4.2 The RCC was informed of the scheduled test.

4.3 Test equipment to be used must be according to standard.

4.4 Personnel assigned to conduct the test should be qualified and knowledgeable.

4.5 Utmost safety of the plant is a priority. Abort the test if conditions will lead to plant tripping.

4.6 The test equipment is installed to monitor the unit output MW, MVAR, KV and the system frequency.

4.7 System at normal condition.

4.8 For reactive power test, voltage variation in the system should not exceed ± 5% at the connecting point. Compensation should be readily available from other generating units to limit voltage within the prescribed limits.

4.9 For reactive power test, the generator capability curve shall be the basis for MVAR loading.

4.10 For contingency reserve test, the unit is on-line and operating in free governor mode.

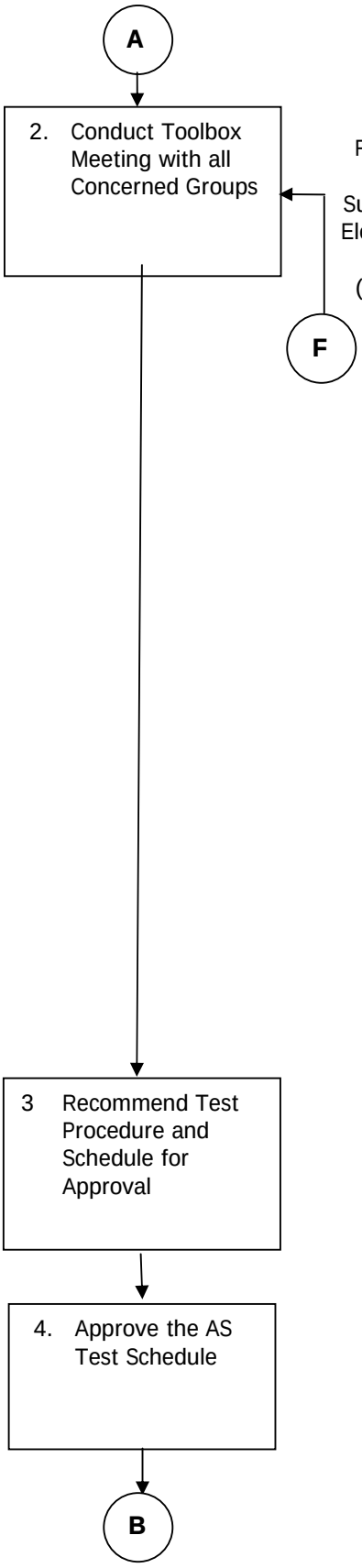
5.0 REFERENCES

5.1 PM-NGCP-01 – Control of IMS Document

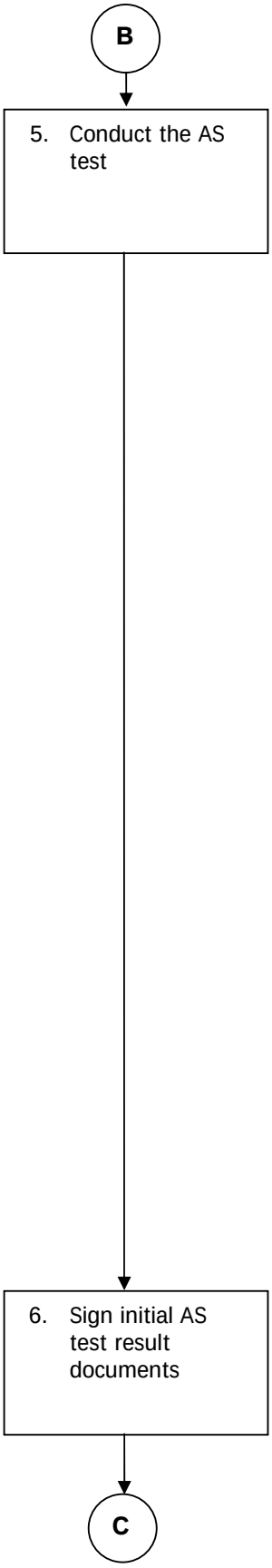
5.2 Philippine Grid Code Amendment No. 1

7.0 PROCEDURE

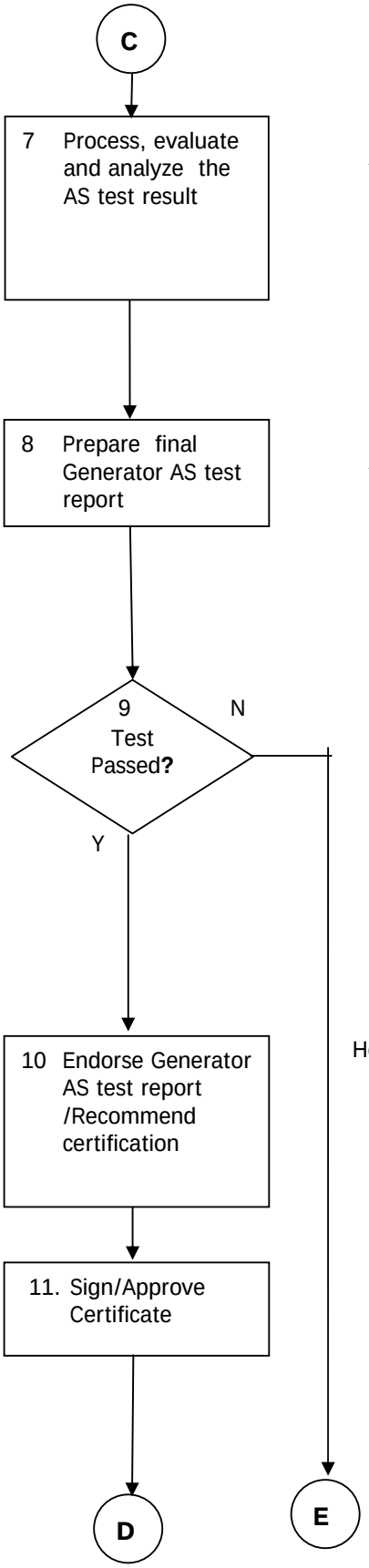
Activity	Responsibility	Details
START		
1. Receive Application for Accreditation as Ancillary Service Provider	PNPD/RSO	1.1 PNPD/RSO upon receipt of application for accreditation and required documents, will perform an initial evaluation for the particular Ancillary Service(s) applied for based on the standard technical requirements. *Note:* This is applicable only to new providers. Generators which havw already been certified are scheduled for an Ancillary Service test for renewal of certification based on the approved work plan schedule of Ancillary Service Section-PNPD annually. 1.2 For a BS Ancillary Service Test, the following shall be considered: 1.2.1 Annual BS test energization is up to the Plant switchyard only for renewal of certification/accreditation. 1.2.2 A BS test shall be extended only to its power restoration highway if either of the following conditions exist: 1. Newly commissioned power plants. 2. Newly refurbished power plants 3. For a certified BS provider, if there is no black-out within the effectivity of Ancillary Services Procurement Agreement. 4. New restoration highway. 1.2.3 Representative from ACC/RCC will conduct the BS test if the activity will be extended to its restoration highway. 1.3 Prepare Notice of Meeting to be signed by Regional Head addressed to all concerned groups (copy furnish NOD, ACTO-SO).
A		



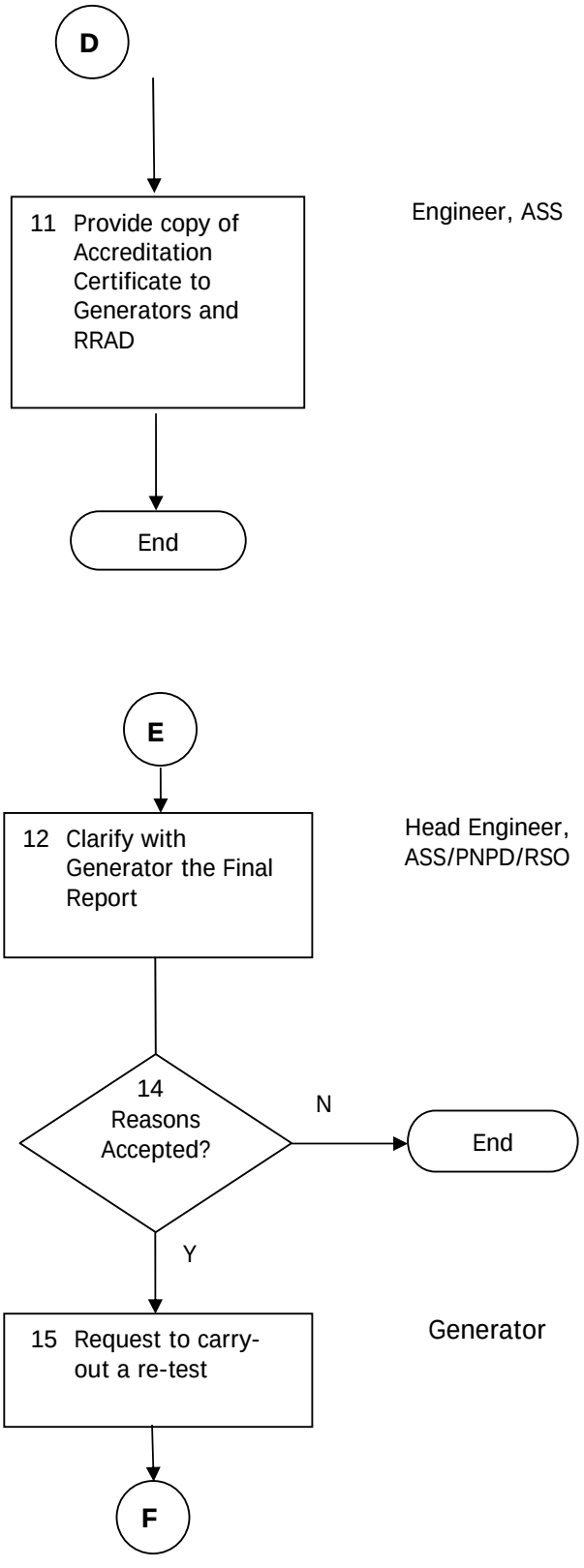
2. Conduct Toolbox Meeting with all Concerned Groups	Head Engineer/ Representative-ASS Plant Operations Superintendent /Plant Electrical Maintenance Engineer (Other NGCP group concerned if applicable)	2.1 Conduct toolbox meeting with all concerned groups with the following agenda: 2.1.1 Schedule of certification test providing for the required 7-days lead time and taking into consideration the following: 1. Inclusion of the schedule in the DGS for non-market based operation. 2. For market-based operation, inclusion of the schedule in the security limits. 3. Final schedule shall have the concurrence of all parties involved. 2.1.2 Test plan and applicable Instruction Manual/s such as: 1. Regulating Reserve (without AGC) test manual IM-LSO-SO-13.01. 2. Regulating Reserve (with AGC) test manual IM-LSO-SO-13.02. 3. CR test manual IM-LSO-SO-13.03. 4. RPS test manual IM-LSO-SO-13.04. 5. BS test manual IM-LSO-SO-13.05. 2.1.3 Logistical requirements which include: 1. Service vehicle and accommodation. 2. PQA, test manuals, technical charts and previous results. 2.1.4 Minutes of meeting shall be properly recorded and signed by all parties involved.
3 Recommend Test Procedure and Schedule for Approval	Head, PNPD	3.1 Review and endorse test plan, applicable Instruction Manual/s and schedule.
4. Approve the AS Test Schedule	Head, RSO	4.1 Head, RSO approve the scheduled AS test. The office of RSO shall provide copy to ACTO-SO and Head-NOD for information.



5. Conduct the AS test	Head Engineer / Lead Engineer, ASS/PNPD/RSO Plant Operations Superintendent /Plant Electrical Maintenance Engineer	5.1 Conduct on-site briefing and discussion on the basic requirements prior to the AS test such as: 5.1.1 Three-line connection diagrams. 5.1.2 Electrical technicians to connect the PQA. 5.1.3 Other technical diagrams, like Power Capability Curve, etc. 5.1.4 Communications Protocol. 5.2 The following shall be present during the briefing: 5.2.1 Plant Operations Superintendent. 5.2.2 Plant Electrical Maintenance Engineer. 5.2.3 SO-ACC Supt/Representative (if necessary). 5.3 Plant operations shift on-duty shall be the party to operate the units under test. 5.4 ASS shall ensure close coordination between the Plant under test and RCC. 5.5 ASS shall decide on the sequence of the test with confirmation from Plant Operations Superintendent-on-duty. 5.6 Conduct any or combination of the following AS tests based on the particular request for certification/ accreditation: 5.6.1 RR AS Test without AGC (IM-LSO-SO-13.01) 5.6.2 RR AS Test with AGC (IM-LSO-SO-13.02) 5.6.3 CR AS Test (IM-LSO-SO-13.03) 5.6.4 RPS AS Test (IM-LSO-SO-13.04) 5.6.5 BS AS Test (IM-LSO-SO-13.05) 5.7 Duration of tests is based on the approved time and schedule which had been submitted to the OPS for clearance and implementation.
6. Sign initial AS test result documents	Head, ASS-PNPD Shift In-Charge, Plant Others (as may be applicable)	6.1 AS Test results shall be signed by the following: 6.1.1 Head Engineer, ASS 6.1.2 Shift-In-Charge, Plant 6.1.3 Plant Manager (if present) 6.1.4 PNPD Head (if present) 6.2 Furnish Plant Shift-In-Charge initial copies of the AS Test reports.



7 Process, evaluate and analyze the AS test result	Engineer, ASS/PNPD/RSO	7.1 Generate, process, analyze and submit to Head Engineer, ASS/PNPD/ RSO on the 8th working day after the test, the following documents: 7.1.1 Generating unit voltage run chart. 7.1.2 Generating unit frequency run chart. 7.1.3 MW/MVAR run chart. 7.1.4 Other parameters as required.
8 Prepare final Generator AS test report	Head Engineer, ASS/PNPD/RSO	8.1 Prepare and submit on the 10th working day after the test, the Plant Ancillary Service tests final report with the following attachments: 8.1.1 AS Test Results (signed). 8.1.2 Relevant Run Charts. 8.1.3 Other charts as necessary.
9 Test Passed?		9.1 If the final AS test results conform to the standards, recommend for certification. 9.2 If the final test report did not meet the required technical standards, inform Generator, copy furnish ACTO. (Go to task 13). ***Note:*** The AS test result should pass the technical standards as stipulated in the ASPP and other standards, or as required by the PGC.
10 Endorse Generator AS test report /Recommend certification	Head, Regional SO	10.1 Endorse Generator AS test report. 10.2 Prepare Certificate. 10.3 Recommend/Endorse certificate to ACTO-SO for approval.
11. Sign/Approve Certificate	ACTO, SO	11.1 Approve certificate. Note: Validity of Certificate is one year, renewable annually.



11 Provide copy of Accreditation Certificate to Generators and RRAD	Engineer, ASS	12.1 Send copy of accreditation/certification to Generator and Revenue and Regulatory Affairs Department. 12.2 Update database of ASP.
12 Clarify with Generator the Final Report	Head Engineer, ASS/PNPD/RSO	13.1 Final test report shall be clarified and discussed with Generator as follows: 1. Reasons and causes of deficiencies or below standard results. 2. Circumstances and other factors, e.g. system disturbances, that occurred during the tests.
14 Reasons Accepted?		14.1 If reasons are acceptable, reconsider Generator's request for a re-test. Otherwise tag the test as failed.
15 Request to carry-out a re-test	Generator	15.1 The Generator shall request to carry-out a re-test. (Repeat task 2 – 8).

Attachment 4

Compliance Monitoring

1.0 Regulating Reserve Ancillary Service Providers

Responsible Person

Engineer

Instructions

1.1 Get the list of all generating units scheduled to provide the service from the day ahead Ancillary Services schedule (DAASS) and their respective Regulating Reserve (FRR) quantities from the reserve profile. Evaluate each generating unit based on its actual Active Power output obtained from the EMS.

1.2 For every dispatch period, evaluate and analyze the data as follows:

For every two (2) seconds compare the generating unit's Active Power output with the generator schedule operating limits as follows:

- If the frequency equals 60 Hz the delivered Regulating Reserve should equal zero (0) MW; and its scheduled Active Power output should equal its actual Active Power output. The allowable variation is ±1 MW or ±1.5% of scheduled Active Power output, whichever is higher.

- If the frequency is between 59.85 Hz and 60 Hz, a generating unit's delivered Regulating Reserve is the difference between its actual Active Power output and its scheduled Active Power output (which must be positive). For undesired operation its actual Active Power output would be less than its scheduled Active Power output. If its scheduled and actual Active Power outputs are equal, the generating unit is not delivering Regulating Reserve.

- If the frequency is between 60 Hz and 60.15Hz, a generating unit's delivered Regulating Reserve is the difference between its actual Active Power output and its scheduled Active Power output (which must be negative). For undesired operation its actual active power output would be more than its scheduled Active Power output. If its scheduled and actual Active Power outputs are equal, the generating unit is not delivering Regulating Reserve.

2.0 Generating Unit Contingency Reserve Service Providers

Responsible Person

Engineer

Instructions

2.1 Get the list of all generating units scheduled to provide the service from the DAASS and its respective Contingency Reserve quantity from the reserve profile. Evaluate each generating unit based on its actual Active Power output obtained from the EMS.

2.2. For every dispatch period, evaluate and analyze the data as follows:

- If the frequency is below 59.85Hz, a generating unit's delivered Contingency Reserve is the difference between its actual Active Power output and its scheduled Active Power output (which must be positive). For undesired operation its actual Active Power output would be less than its scheduled Active Power output. If its scheduled and actual Active Power outputs are equal, the generating unit is not delivering Regulating Reserve.

3.0 Interruptible Load Service Providers

The ERC has ordered the Transmission Provider to develop a monitoring procedure for Qualified Interruptible Loads and following due process and approval by the ERC, this procedure will be inserted here.

4.0 Reactive Power Support Service Providers

Responsible Person

Engineer

Instruction

4.1 Get the list of all generating units scheduled to provide Reactive Power Support Ancillary Service from the daily Reactive Power generation schedule. Evaluate each generating unit based on its actual Reactive Power output obtained from EMS.

4.2 For every dispatch period compare its scheduled Reactive Power output with its actual Reactive Power output as follows

- A generating unit is supplying Reactive Power Support Ancillary Service when its actual Reactive Power output is outside the Power Factor range of 0.85 lagging to 0.90 leading but within the generating unit's Reactive Power capability curve. It's delivered Reactive Power Support is the quantity of Reactive Power that it delivers or absorbs outside this range.

- An undesirable situation arises when a generating unit's actual Reactive Power output does not equal its scheduled Reactive Power output and the bus voltage is outside the range $\pm$5% of nominal.

5.0 Black Start Service Providers

Responsible Person

Engineer

Instruction

5.1 Obtain from EMS the alarm event data and the Dispatch Instruction from the System Operator. Use the existing Restoration Highways as reference, to get the list of generating units with Black Start capability.

5.2 Following a Power System failure, a generating unit has delivered Black Start Ancillary Service if it is ready deliver Active Power within thirty (30) minutes from receipt of a Dispatch Instruction for Black Start from the System Operator and if can deliver Active Power at its scheduled Active Power output and sustain it at this level for twelve (12) hours.

6.0 Dispatchable Reserve Service Providers

Responsible Person

Engineer

Instruction

6.1 Get the list of all generating units scheduled to provide the Dispatchable Reserve Ancillary Service from the DAASS and their respective Dispatchable

Reserve quantities from the reserve profile. Evaluate each generating unit based on the actual Active Power output obtained from the EMS.

6.2 From the Dispatch Instruction and alarm event data, evaluate the generating unit base on the requirement stated below:

- Dispatchable Reserve Ancillary Service is delivered on time if the generating unit is synchronized within 15 minutes from receipt of the Dispatch Instruction and can sustain its scheduled Active Power output continuously or up to eight (8) hours.

Attachment 5

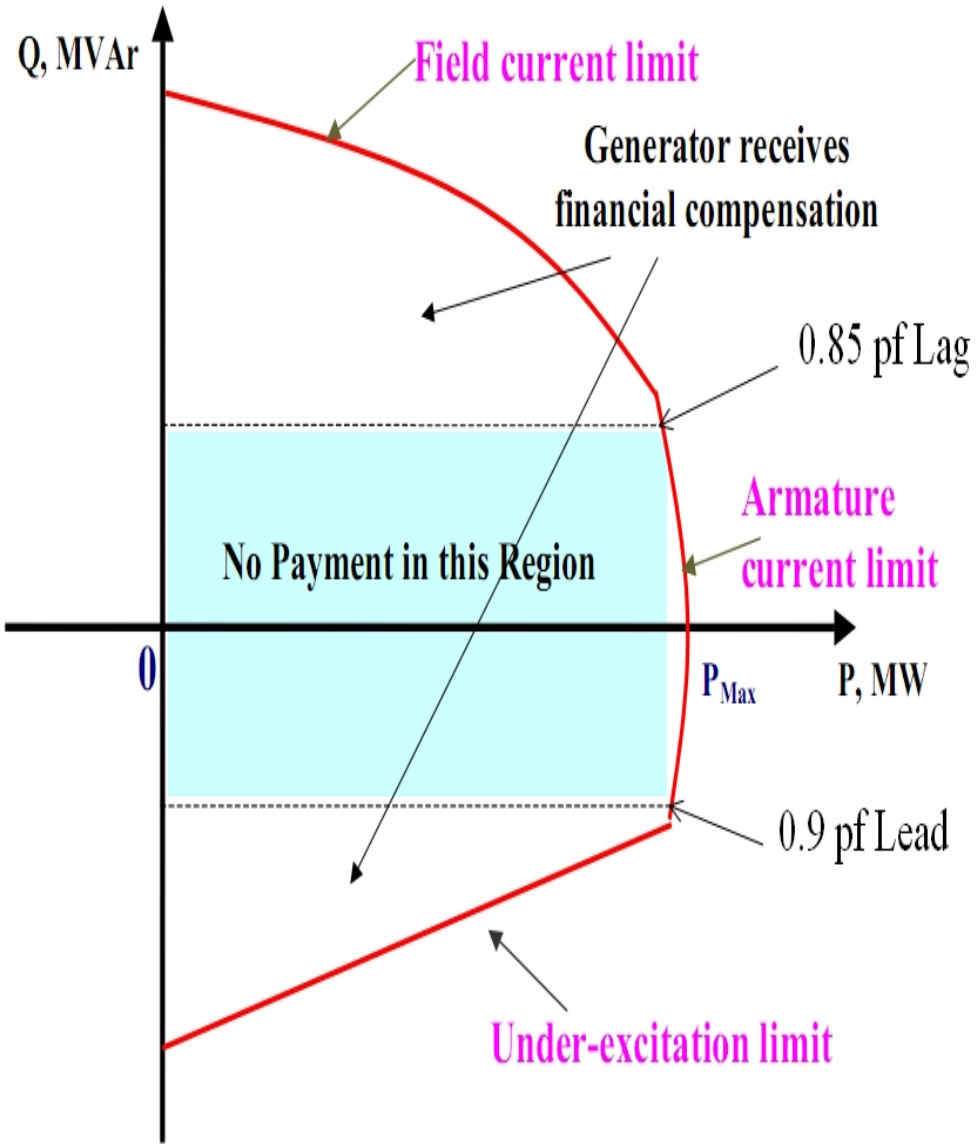
Ancillary Services Standard Technical Requirements

	Performance Measures	Performance Criteria	Monitoring Scheme
Regulating Reserve	Primary Response (Speed Governor) Regulating Capacity, ±MW	Within ±1% declared	**Monitored from EMS/SCADA** 1. Continuous monitoring
	Static Gain, MW/Hz	Within ±5% declared	
	Speed droop setting	5% or less	
	Response time	5 seconds maximum	
	Dead band setting (±) Hz	Within 0.15	
	Sustainable time	25 seconds	
	Secondary Response (AGC) Regulating Capacity, ±MW	Within ±1% declared	
	Ramping Rate, ±MW/min	Less than ±10% declared	
	Response time	25 seconds maximum	
	Dead band setting (±) Hz	Within 0.15	
	Sustainable time	At least 30 minutes	
Contingency Reserve	Primary Response (Speed Governor) Reserve Capacity, MW	Within ±1% declared	Monitored from EMS/SCADA triggered by: 1. Actual restoration of spinning reserve 2. Spot check
	Speed droop setting	5% or less	
	Static Gain, MW/Hz	Within ±5% declared	
	Maximum time to full reserve capacity	10 minutes	
	Dead band setting (-) Hz	Greater than 0.15 but less than 0.30	
	Secondary Response (AGC or Manual) Reserve Capacity, MW	Within ±1% declared	
	Maximum time to full reserve capacity	10 minutes	
	Dead band setting (-) Hz	Greater than 0.15 but less than 0.30	
	Ramping Rate, ±MW/min	Less than ±10% declared	
	Sustainable time	At least 30 minutes	

	Performance Measures	Performance Criteria	Monitoring Scheme
Interruptible Load Dispatchable Power	To be added by NGCP, following due process and approval by the ERC	To be added by NGCP, following due process and approval by the ERC	To be added by NGCP, following due process and approval by the ERC MonitoredfromEMS/SCADAtriggeredby: 1. Actual restoration of spinning reserve 2. Spot check
	Back-up Capacity, MW	Within ±1% declared	
	Synchronizing time	Within 15 minutes	
	Ramping Rate, ±MW/min	Within ±10% declared	
	Sustainable time	Minimum of 8 hours	
Black-Start Capability	Black start Capacity, MW	Within ±1% declared	MonitoredfromEMS/SCADAtriggeredby: 1. Actual system restoration 2. Simulated emergency exercises 3. Spot check
	Maximum time to Synchronize	Within 30 minutes	
	Maximum time at no load, min	Within 10% declared	
	Load Pick-up Rate, MW/min	Within ±10% declared	
	Overload Capacity, MW	Within ±1% declared	
	Sustainable time	At least 12 hours	
	Reactive Power Range, ±MVAr	Within ±5% declared	
Reactive Power Support	Reactive Power Capability	Within ±5% declared	***Monitored from EMS/SCADA***
	Power Factor within Capability Curve	Less than 0.85 lagging and less than 0.90 leading	

Attachment 6

Generator Reactive Capability Limitation



Attachment 7

Sample Computations
Section 4.5 Payment to Ancillary Services Providers

A. REGULATING RESERVE

LFFR Payment = $\sum^{n}{}_{h}$ ($SQ^{h}{}_{i}$ x $Rate^{h}{}_{LFFR}$)

Scheduled Quantity (SQ), kW	50,000
Rate, PhP per kW per hour	6.1399
No. of Hours,h	744
Payment, PhP	228,404,338.58
Adjustment (PhP)	7,981,872.05
LFFR Payment (PhP)	***220,422,466.54***

B. SPINNING RESERVE (SR)

SR Payment = $\sum^{h}{}_{n}$ ($SQ^{h}{}_{i}$ x $Rate^{h}{}_{SR}$)

Scheduled Quantity (SQ), kW	50,000
Rate, PhP per kW per hour	2.9472
No. of Hours,h	744
Payment, PhP	109,634,082.52
Adjustment, PhP	5,599,590.24
SR Payment (PhP)	***104,034,492.28***

C. INTERRUPTIBLE LOAD (IL)

To be added by NGCP, following due process and approval by the ERC

D. DISPATCHABLE RESERVE (DR)

BUR Payment = $\sum^{h}_{n}$ (SQ^{h}_{i} x $Rate^{h}_{BUR}$ - BUR Adj^{h}_{i})

Scheduled Quantity (SQ), kW	50,000
Rate, PhP per kW per hour	1.3098
No. of Hours,h	744
Payment, PhP	48,026,583.00
BUR Adj, PhP	699,675.90
BUR Payment (PhP)	***47,326,907.11***

E. REACTIVE POWER SUPPORT SERVICE (RS)

RS Payment = $\sum^{h}_{n}$ (SQ^{h}_{i} x $Rate^{h}_{RS}$ - RS Adj^{h}_{i})

Scheduled Quantity (SQ), kVAR	50,000
Rate, PhP per kVAR per hour	0.0025
No. of Hours,h	744
Payment, PhP	93,930.00
RS Adj, PhP	9,393.00
RS Payment (PhP)	***84,537.00***

F. BLACK START SERVICE (BS) (Monthly Payment per provider)

BS Payment = (Annual Cost of Proving BS / 12) - BS Adj

Annual Cost, PhP	50,000,000.00
No. of Months	12.00
Payment, PhP	4,166,666.67
BS Adj., PhP	1,041,666.67
BS Payment (PhP)	***3,125,000.00***

Note: The sample computations are provided to illustrate the application of the formula in Section 4.5. Prices (per unit/per type of service) or the cost of the Ancillary Services are only used for simulation purposes.