

WHOLESALE ELECTRICITY SPOT MARKET (WESM) DESIGN STUDY

Phase 2

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Final

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Glossary

ACMS	Automated Conformance Monitoring System
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator (formerly NEMMCO)
AER	Australian Energy Regulator
AGC	Automatic Generation Control
ANEM	Australian National Electricity Market
ASDP	Ancillary Service Dispatch Price
ASP	Ancillary Service Payment
ASQ	Ancillary Service Quantity
BCQ	Bilateral Contract Quantity
CfD	Contract for Difference
CON	Contingency Reserve
CVC	Constraint Violation Cost
DAM	Day Ahead Market
DAP	Day Ahead Projection
DIS	Dispatchable Reserve
DOE	Philippines Department of Energy
DU	Distribution Utility
EAP	Ex-Post Quantity
EAP	Ex-Ante Price
EAQ	Ex-Ante Quantity
EDP	Energy Dispatch Price
EMS	Energy Management System
EPIRA	Electric Power Industry Reform Act
EPP	Ex-Post Price
ERC	Philippines Energy Regulatory Commission
ERCOT	Electricity Reliability Council of Texas (U.S. Electricity Market)
ETP	Energy Trading Price
FCAS	Frequency Control Ancillary Services
FTR	Financial Transmission Right
HAD	Hour Ahead Dispatch
HVDC	High Voltage Direct Current
ICCP	Inter-control Centre Communication Protocol
IEEE	Institute of Electrical and Electronics Engineers
IES	Intelligent Energy Systems Pty Ltd
ILD	Interruptible Load
IRR	Implementing Rules and Regulations
KPX	Korean Power Exchange
LR	Line Rental
LRF	Load Relief Factor
MDOM	Market Dispatch Optimisation Model
MMS	Market Management System



MNM	Market Network Model
MO	Market Operator
MOT	Merit Order Table
MPI	Market Participant Interface
MQ	Metered Quantity
MRR	Market Re-Run
MRU	Must run unit
MTN	Market Trading Node
NECA	National Electricity Code Administrator (now AER)
NEMDE	National Electricity Market Dispatch Engine (in Australian NEM)
NEMMCO	National Electricity Market Management Company (now AEMO)
NEMS	National Electricity Market of Singapore
NGCP	National Grid Company Philippines
NPC	Philippines National Power Corporation
PAC	PEM (Philippines Electricity Market) Audit Committee
PCRM	Pricing and Cost Recovery Mechanism for Reserves
PDM	Price Determination Methodology
PEMC	Philippines Electricity Market Corporation
PEN	Pricing Error Notice
PJM	Pennsylvania, New Jersey and Maryland electricity market (a U.S electricity market)
Pmin	Technical minimum power output for a generator that is running
PPA	Power Purchase Agreement
PSALM	Power Sector Assets and Liabilities Management Corporation
RE	Renewable Energy
REF	Reserve Effectiveness Factor
REG	Regulating Reserve
RFP	Request for Proposal
RTD	Real Time Dispatch
RTX	Ex-Post Dispatch
SCADA	Supervisory Control and Data Acquisition
SDLF	Similar Day Load Forecasting
SEM	Ireland Single Electricity Market
SO	System Operator
SPS	System Preservation Scheme
SSLA	Site Specific Loss Adjustment
STFM	Short term forward market
SWA	SW Advisory Pty Ltd
TCG	Transmission Constraint Group
ToR	Terms of reference
TTA	Total Trading Amount
VCGM	Vietnam Competitive Generation Market
VoLL	Value of Lost Load
WAP	Week Ahead Projection



WEM	Western Australia Electricity Market
WESM	Philippines Wholesale Electricity Spot Market



Executive Summary

Introduction

The Philippine Electricity Market Corporation (PEMC) commissioned Intelligent Energy Systems Pty Ltd (IES), in association with SW Advisory and Dr. Ross Baldick, to undertake a design study of the Philippines' Wholesale Electricity Spot Market (WESM).

The overall aim of the study was to address several market design and implementation issues, which are undermining the efficiency of the WESM, that were identified in the first Market Operations Audit¹ undertaken by Deloitte and IES and in the second audit² undertaken by PA Consulting.

Objectives of Phase 2

This report contains the findings for Phase 2 of the WESM Design Study, which was concerned with addressing the following scope of work:

The Consultant shall provide technical assistance in assessing the feasibility of shortening of the one hour trading interval in the WESM and provide advice and recommendations on the appropriate implementation scheme. The Consultant is also expected to:

- a. *Recommend an appropriate dispatch interval to be used;
Determine whether the distinction between ex-ante and ex-post prices could be removed; and*
- b. *Determine associate changes to the overall market design upon shortening of trading interval.*

For each of the phases, the Consultant shall provide the following services:

1. *Assess the feasibility of options or solutions identified;*
2. *Provide appropriate recommendations to address the market issues;*
3. *Provide simulations, impact analysis and other measurable basis/proof to support recommendations;*
4. *Identify and draft Rules and Market Manual changes, if any, to effect the proposed recommendations;*
5. *Provide the necessary reports, studies and documentations;*
6. *Present the results of the study to PEMC, DOE and ERC, or as required, to the PEM Committees; and*
7. *Act as expert witness, as required, during Regulatory hearings.*

¹ First Audit: Deloitte and IES "Philippine Electricity Market Corporation Independent Spot Market Audit Report1 on the Systems and Procedures of Market Operations", July 2010.

² Second Audit: PA Consulting Group "Philippine Electricity Market Corporation Process Review: Independent Operational Audit of the Systems and Procedures on Market Operations", 26 August 2011.



Approach to Phase 2

The approach adopted for Phase 2 was similar to that taken in Phase 1. In particular:

- We reviewed material supplied by PEMC and the System Operator (SO) regarding the issues;
- We had meetings, workshops and consultations with PEMC, the SO, Distribution Utilities (DUs), generators, Grid Management Committee (GMC), Electricity Regulatory Commission (ERC), Department of Energy (DOE) and other stakeholders to discuss the key issues concerning the study and to set out our proposed enhancements to the WESM;
- We collected feedback on our proposed enhancements and rule changes from the stakeholders and have refined our recommendations and analyses to address the issues and concerns raised;
- We collected and analysed market data, provided by PEMC and the SO, on dispatch, 1-minute SCADA measurements, operation of MRUs and information on ancillary service providers etc. in order to better understand the issues concerning a shorter trading interval;
- From our analyses we assessed the market outcomes as to what could reasonably be expected in an efficient market and with what we have observed in other similar markets;
- From our analyses and existing suggestions for changes in market design or implementation we developed a set of options or proposed changes to the WESM;
- We analysed these options in terms of the impacts on market efficiency and transparency; and
- Based on our analysis of the options we made recommendations and conclusions.

This report can be considered to be a more detailed assessment of the general recommendation made in Phase 1 to introduce a shorter dispatch interval in the WESM. As such this report ties together the recommendations made in Phase 1 and combines them with additional recommendations that arise when considering the introduction of a shorter dispatch interval.

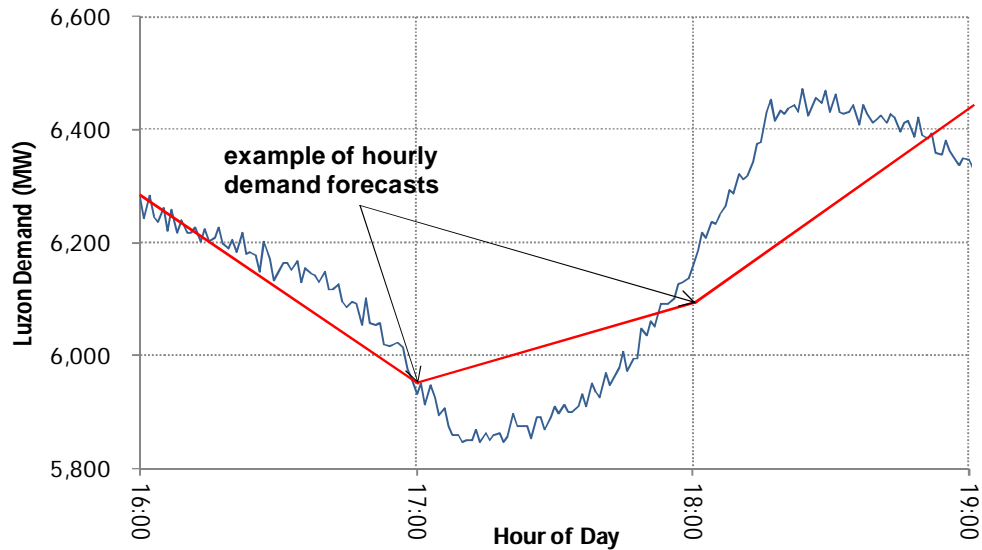
Motivation for Implementing a Shorter Dispatch Interval

In the WESM the market operator (MO) and SO are separate entities. The MO's role and responsibilities are defined in the Market Rules, while the SO's role and responsibilities are set out in the Grid Code and the Market Rules. The WESM presently operates based on a trading interval of 1 hour for the purpose of dispatch, pricing and settlements. The MO communicates to the SO the hourly dispatch schedules of all generators and provides the SO with a merit-order table (MOT), which is used to make unconstrained adjustments to dispatch schedules of generators within the hour.

Within a 1 hour trading period there can be significant variations in demand, as evidenced by the diagram below. To ensure the power system is operated within a secure envelope and to maintain balance in supply and demand, the SO makes adjustments using the MOT. However, because the MOT does not include any



constraints, there is no guarantee that the adjustments will satisfy operational limits on generators such as their minimum stable levels or ensuring the power system is operated within a secure envelope. Within a 1-hour trading period, the SO may also take other discretionary which are not transparent.



The reason for assessing a shorter dispatch interval in the WESM was to assess whether it would be feasible to gain the following benefits:

- Reduce the need for the SO to exercise discretion within the hour. A shorter dispatch interval means that market dispatches will be updated more frequently to reflect system conditions and can be adjusted while also ensuring the power system is operated within a secure envelope.
- As the energy market is able to perform a greater amount of load following, there will be a reduction in the amount of capacity that is required to provide frequency regulation ancillary services, and any ancillary services that have long response times will not be required, as their responses can be dispatched directly in the energy market.
- Enhance the transparency of SO actions on market outcomes, since it will be necessary for the SO to take actions directly via the market, in the form of generator offers (for must-run plant), security constraints and the specification of any ancillary service requirements.
- More efficient use of the transmission system, since the market dispatch model will be more frequently updated based on current system conditions, it is feasible to utilise short-term thermal ratings for management of thermal transmission security limits.
- Operating on a shorter dispatch interval, in combination with a shorter gate closure and adequate provision of information, will enable participants to respond more



efficiently to changed circumstances, which is consistent with the WESM's decentralised market design philosophy.

Organisation of Recommendations

The shorter dispatch interval depends on a number of the recommendations that were made in Phase 1. As such this report ties together the recommendations made in Phase 1 and Phase 2 on a shorter dispatch interval. Furthermore, the analysis of a shorter dispatch interval necessitated consideration of issues outside the market rules and market implementation, most notably the Grid Code and the procedures for system operations. It is also important to ensure the impact on market IT systems are appropriately considered and that a carefully developed transition path towards the new Market Management System (MMS) is established.

As such we present the recommendations in this report for both Phase 1 and Phase 2, organised in the following areas:

- Market rules and implementation recommendations;
- Grid Code and system operation procedures recommendations;
- IT system enhancements; and
- Transition to new MMS.

It should be noted that the recommendations made here do not take into consideration the advantages or disadvantages of a day-ahead market (DAM) as this will be discussed in the Phase 3 report.

Market Rules and Market Implementation Recommendations

Our recommended options for design and implementation changes to the WESM (across Phase 1 and Phase 2) being as follows for the WESM Rules and market operations:

- Set Pmin to zero in the market dispatch optimisation³.
- Changing the values and priorities of some of the Constraint Violation Coefficients (CVCs) and, perhaps, using a range of Nodal Value of Lost Load (VoLL) prices to facilitate orderly load shedding and rotation of load shedding.
- Set a market price cap and market price floor for the WESM.
- Set a bid floor price.
- Implement local PENs as an interim measure to automation of market re-runs.
- Automate the management of constraint violations, for pricing purposes, in real time dispatch (RTD), hour ahead dispatch (HAD), day-ahead projections (DAP) and week ahead projections (WAP), to eliminate the need to issue PENs.

³ Note that we use the term: "Set Pmin to zero" as a shorthand way of saying that the constraints in the market clearing engine (MDOM) that force generators to generate at or above their Pmin levels would set Pmin to zero. That is, the MDOM could dispatch a unit below its Pmin and to avoid this situation a generator would have to appropriately construct its bids and if it did occur to rebid in such a way as to remove this problem. We argue in Phase 1 that it is useful to maintain the Pmin constraints and maintain the ability to set Pmin to non-zero in order to enable the SO to force generators to be dispatched to specific output levels in situations where it is necessary to direct generators.



- Shorten gate closure to say 30 seconds before the start of the next dispatch interval (essentially limit gate closure to the time at which the market clearing engine commences solving).
- Include Distribution Utility's (DU's) sub-transmission in dispatch and pricing:
 - include key sub-transmission of DU's in the Market Network Model (MNM);
 - interface between SO and DU set up to convey real-time information on state of sub-transmission network; and
 - update the SO's snapshot files provided to the MO to reflect the state (and ratings) of the additional elements of the MNM.
- Improve the Must Run Unit (MRU)_arrangements for payment and interaction with the WESM.
- Introduce *dispatch intervals* as distinct from 1-hour *trading intervals*, where there is an integer number of *dispatch intervals* per *trading interval* and *dispatch intervals* are used for dispatching generation and loads and the *trading intervals* are used for energy settlements and DAP and WAP. The shorter dispatch interval essentially replaces the MOT and enhances pricing.
- Adopt a scheme of *dispatch interval nodal prices* and *trading interval nodal prices* for energy. The *trading interval nodal price* for a *market trading node* is the generation weighted or load weighted average of the corresponding *dispatch interval nodal prices* for that *market trading node*.
- Adopt a scheme of *dispatch interval regional prices* and *trading interval regional prices* for reserves. The *trading interval reserve price* for a *region* and *reserve category* is the regional requirement weighted average of the corresponding *dispatch interval regional reserve prices* for that *reserve category*.
- Adopt *ex-ante* pricing for energy and reserves. The *ex-ante* nodal energy price for each market trading node in any dispatch interval reflects the marginal costs of supply or in cases of supply shortage, the market price cap or in cases of excess supply, the market price floor (see Phase 1). The marginal cost of supply is determined from the shadow price of the energy balance equation or equivalent from the market dispatch optimisation model.
- The *ex-ante* regional reserve dispatch price for each market reserve region in each dispatch interval reflects the marginal costs of supply and is determined from the shadow price of the relevant reserve requirement constraint or equivalent from the market dispatch optimisation model.
- Implement a dispatch interval of duration 5-minutes.
- Settlements for energy to be based on *ex-ante* nodal energy trading prices and metered energy quantities for all market participants (scheduled and non-scheduled).
- Ancillary service settlements based on dispatch interval prices and quantities. For consistency with market settlements for energy, they could be aggregated on an hourly basis.
- Enhance the DAP process as follows (refer to Phase 1 report):



- execute DAP hourly;
- extend horizon to always be at least 24-hours ahead; and
- implement DAP sensitivities (see section 9.18 of the Phase 1 report);
- Introduce a HAD process as a 1-hour extension of the RTD with periodicity equal to that used for a shorter dispatch interval.
- Enhance the approach for short term demand forecasting to use nodal-based forecasts using a simple time series model. We make the observation that some research based on historical 5-minute SCADA snapshot data could be undertaken in order to determine the most appropriate time series model, calibrate them and assess their accuracy.
- Enhance determination of N-1 thermal security limits so that post-contingent power flows will be bounded by short-term thermal ratings rather than the continuous ratings.
- Allow some violation of N-1 thermal security limits when there is an armed load shedding scheme which could be used to prevent any overloading should a contingency occur.
- Introduce market-based ancillary service arrangements for frequency control (note that this has already been approved but requires new systems or system enhancements to manage more reserve and regulation services) but with the following WESM Rules / Pricing and Cost Recovery Mechanism for Reserves (PCRM) enhancements:
 - refine the categories of ancillary service to be more appropriate for a 5-minute dispatch interval;
 - co-optimisation of the provision of energy and reserves;
 - co-optimisation of the requirements of energy and contingency reserves;
 - base settlements of ancillary services on dispatch interval prices and quantities;
 - zonal reserves pricing and cost-recovery;
 - introduce joint capacity constraints and joint ramp rates to ensure that the combination of energy and multiple reserve dispatches will be physically feasible;
 - remove the requirement to “limit the schedule of a reserve provider to strictly one reserve category per interval”; and
 - remove the use of reserve effectiveness factors (REFs).
- Establish a transparent procedure to address the issue of missing or erroneous real-time data and/or handle the IT system failures.

Grid Code and System Operation Recommendations

The following recommended options are applicable to the Grid Code and system operations:

- Dispatching enhancements:
 - use short-term dispatch targets instead of making adjustments based on MOT;



- set Automatic Generation Control (AGC) participation factors to reflect outcomes of frequency control ancillary service market outcomes for regulation;
- Power system security and ancillary services management enhancements:
 - Determine appropriate short-term ratings for transmission lines and transformers and advise the MO appropriately so they can be used to manage post-contingent power flows in the N-1 thermal security limits;
 - Advise the MO of the details of the transmission lines that are managed via the System Preservation Scheme (SPS). This is so that they can be properly reflected in the market dispatch and pricing model.
 - Other power system security limits. The SO will need to advise the MO of any security limits above and beyond the N-1 thermal limits that are automatically generated by the MO's MMS, rather than intervene directly in dispatch, which should only occur if the power system enters an abnormal condition.
 - Enhance the management of MRUs to be more transparent, to reduce SO discretion and to be more market-based.
 - Ancillary service requirements. SO will need to advise the MO of the requirements that are necessary and implement processes to determine the requirements.
- Enhance the content of system snapshot files, in particular:
 - real-time short-term and continuous thermal ratings of transmission lines; and
 - information on sub-transmission network elements of the DUs that would materially improve dispatch and pricing outcomes;
- Potential Grid Code enhancements:
 - make going on AGC mandatory for participants that are centrally dispatched and with capacity greater than a certain size, such as 30 MW. For an interim period the SO could charge a management fee as an incentive for generators to go on AGC sooner. All newly connected generators should be required to go on AGC.
 - require short-term thermal ratings to be determined for all transmission lines and transformers and for the MO to be advised of them for use in the market dispatch and pricing model;
 - Enhance specification of frequency standards. Rather than base frequency standards on a deterministic criteria that is independent of the power system state, we suggest that the following approach be taken:
 - frequency standards are specified in a probabilistic manner, for example frequency within bounds 99% of the time;
 - use of wider frequency bands for the alert and/or emergency states compared to the system normal state;
 - tighten the frequency band for the normal state compared to that used in alert and/or emergency states;
 - the need to return frequency back to the normal state following a contingency within a prescribed period of time (for example, 10 minutes)



following a contingency, system frequency is to return to the system normal state);

- Harmonise the Grid Code and Market Rules with the areas requiring the most attention being:
 - move the elements concerned with operations and management of power system security out of the Grid Code and into the WESM Rules. This would require a detailed review into the areas of overlap between the two documents and is beyond the scope of this project;
 - introduce consistent definitions for ancillary services between the Grid Code, WESM rules and PCRM;
 - specification / determination of ancillary service requirements consistent between Grid Code, WESM rules and PCRM; and
 - ensure consistency between system operation actions and the priorities implied in the CVC penalty values (see Phase 1 report, section 4).
- Enhance system performance and compliance monitoring:
 - Whether dispatch targets were followed;
 - whether frequency regulation was provided for any generator that is on frequency regulation;
 - whether responses to power system events are consistent with the responses procured in the market-based ancillary service markets;
 - whether the MO is recruiting too much or not enough ancillary services to maintain the power system in a secure state (as defined by the frequency standards in the Grid Code).

IT Systems Enhancements

Enhancements will be required to the IT Systems of the MO, SO and market participants, in support of a shorter dispatch interval and the broader package of proposed enhancements recommended in the Phase 1 and Phase 2 reports.

The following is a summary of the main enhancements for the MO:

- Communications infrastructure:
 - Inter-control Centre Communication Protocol (ICCP)_connection between SO and MO for transfer;
 - upgraded bandwidth to handle increase in data transfers by a factor of 100;
 - sufficient redundancy in SCADA networks and WESM backbone networks;
- Market clearing engine model and supporting infrastructure enhanced to manage the Phase 1 and Phase 2 recommendations, which includes:
 - co-optimised energy and ancillary services;
 - ancillary services representation to reflect: reserve regions, optimised requirements, joint capacity limits and joint ramping limits,
 - automated handling of violated constraints;



- thermal security limits based on short-term ratings;
- implemented in a higher-level modelling language to enable refinements as market evolves;
- production and pre-production environments;
- sufficient offline systems to enable study-mode, concept testing and independent auditing;
- MMS database enhanced to reflect changes to market processes, shorter dispatch interval and to handle the outcomes of ancillary services market;
- Settlement systems enhanced as follows:
 - determine energy trading prices and for settlements to be based on ex-ante trading prices and metered quantities;
 - ancillary service settlements introduced (based on the dispatch interval outcomes);
- MPI and public (web-based) interfaces:
 - enhanced to reflect additional data requirements from a shorter dispatch interval, introducing ancillary services, additional market process (HAD) and changes to the DAP;

The following are the main enhancements required for the SO:

- Enhancing AGC to take inputs from market clearing engine, determine linear energy targets for generators and regulation participation factors that reflect the outcomes of market-based ancillary services;
- ICCP connections between MO and SO and key DUs and SO;
- State-estimator to enhance quality of snapshot data or SCADA points transferred by ICCP and used in the dispatch optimisation or demand forecasting;
- Enhance SCADA snapshots to convey short-term thermal ratings of transmission lines and the status of the any critical sub-transmission networks of the DUs;
- Implement (or modify the existing) ACMS (see section 4.8);

The following are enhancements that will be required by market participants:

- Adjust systems and communication links to MO to handle increased volume of data from MO; and
- We suggest making AGC mandatory for generators exceeding a certain threshold, and so they will need to go onto AGC.

We also suggest that a careful plan be developed to ensure that the new (or substantially upgraded) MMS will be able to deliver the full spectrum of enhancements that are required in the WESM and such that the transition from the existing systems to the new systems is successful.

Transition to New MMS

Given the commercial implications of making significant changes to market systems and the need to maintain the integrity of the market, it is paramount that a systematic and well-defined transition path is established as part of phasing in a new MMS.



The following are recommendations are made for phasing in a new MMS that can support the recommendations made in Phase 1 and Phase 2:

- Refine the MMS specifications to clearly address the new requirements (in particular, ensure that the issues raised in the Phase 1 and Phase 2 reports are reflected as well as to ensure that any shortcomings identified in the existing MMS are avoided);
- Develop and prototype a higher level dispatch and pricing mathematical formulation and requirements, an approach for doing this could be:
 - develop a mathematical formulation of the market dispatch optimisation similar to what has been implemented in Singapore⁴
 - implement the model in a higher level mathematical programming modelling language such as AMPL (www.ampl.com), AIMMS (www.aimms.com/aimms/overview), GAMS (www.gams.com), or GNU mathprog (www.gnu.org/software/glpk)
 - Once a prototype has been developed, a range of market scenarios could be used to test the formulation and approach. This will inevitably lead to some fine tuning of the approach and revisions of the prototype. This could continue for several iterations before the model and approach are finalised.
 - Having developed and tested a dispatch optimisation prototype should enable PEMC to negotiate effectively with any proposed vendors or possibly develop the system within PEMC and interface it to the vendor's infrastructure.
- Introduce the new (or substantially enhanced) MMS initially as a “shadow system” to the existing system (so there would be two systems operating in parallel for a period of time) so it can be thoroughly tested and transition to the new system carefully managed;
- Adequate redundancy introduced for all hardware, software, communications networks and key staff;
- Project should set out a clearly defined set of phases and for each phase a set of pre-requisites that must be satisfied before advancing to the next phase. Some examples include:
 - communications infrastructure properly tested and confirmed to be adequate for the increase in bandwidth;
 - independent audit of the new / enhanced market clearing engine optimisation;
 - independent audit of the new / enhanced MMS;
 - market participants confirm that they are able to interoperate with the new system (and have a process of addressing issues that may arise);
 - testing of real-time dispatch instructions being issued to generators;
 - 3 to 6 months of shadow system working in parallel without any major incidents prior to switching over to it;
 - testing of all fail-over, backup and redundant systems; and

⁴ . The Singaporean formulation is in Appendix 6D to the Singapore Electricity Market Rules (<https://www.emcsg.com/marketrules>).



- Adequate training of all staff.

Net Benefit of Design and Implementation Changes

The following is a summary of the costs:

- For the MO:
 - cost of new or enhanced MMS;
 - cost of maintaining the new systems including support and maintenance fees and licenses fees;
 - IT hardware and communication system upgrades;
 - staff to implement and manage the new systems;
- For the SO (and a select number of DUs):
 - SCADA/EMS AGC enhancements;
 - ICCP connections to DUs;
 - conformance monitoring system enhancements;
- For market participants:
 - communications infrastructure to support increase in bandwidth;
 - IT system enhancements to handle shorter dispatch interval; and
 - Cost of going onto AGC.

The following is a summary of the benefits that we have identified (arising from the enhancements identified in both Phase 1 and Phase 2):

- Reduction in capacity gap – more capacity offered to the market;
- Reduced fuel costs as more expensive units may not be dispatched at all, rather than be dispatched to their Pmins;
- Reduction in ancillary service costs due to shorter dispatch interval, co-optimisation of reserves and more accurate demand forecasts;
- Greater ability for generators to manage their generation plant efficiently in the WESM;
- Greater demand side participation because firm ex-ante prices delivered at the start of each dispatch interval;
- Greater utilisation of the transmission system;
- More accurate tracking of dispatch targets and less non-conformance from having more generators on AGC;
- Greater transparency in market operations; and
- Given the above, greater encouragement of new entrants when they are required by the market.

Assuming that the Phase 1 and Phase 2 enhancements are made, and the dispatch interval is 5-minutes, then assuming the new MMS system has a life of 7 years we get the



costs and benefits presented in the table below⁵. Based on this analysis the suggested WESM design and implementation changes supported by a new MMS for PEMC would have substantial net economic benefits, with a net present value of the order PhP 13.5 billion (US\$ 323 million). If we were to repeat the exercise with a 10-minute dispatch interval were to be implemented then the benefits would be of the order PhP 12.4 billion (US\$ 298 million). This is illustrated in the table below.

Year	Costs			Benefits		Net Benefit
	MMS	SO	MPs	Reduction in Capacity Gap	Reduction in Regulation Requirement	Total
0	-1,000	-21	-417	0	0	-1,437
1	-250	-5	-104	3,024	671	3,335
2	-250	-5	-104	3,024	671	3,335
3	-250	-5	-104	3,024	671	3,335
4	-250	-5	-104	3,024	671	3,335
5	-250	-5	-104	3,024	671	3,335
6	-250	-5	-104	3,024	671	3,335
7	-250	-5	-104	3,024	671	3,335
Present Value	-2,016	-42	-840	13,383	2,968	13,453

Conclusions

There are a number of market design and implementation changes that would appear to significantly enhance the efficiency, reliability, system security and transparency of the WESM. These have been outlined in this report with the focus being on a shorter dispatch interval. Given the interdependency with a number of Phase 1 findings, we present a cost-benefit analysis that is inclusive of the issues identified in this report and those of the Phase 1 report. In doing so we have found that benefits of the market changes far exceed the costs of a new MMS and deliver a substantial net present value to the Philippines. These changes can only be supported by either a new MMS or a substantially enhanced MMS.

Our suggested way forward, is for PEMC to immediately implement the changes that can be done without procuring a new MMS that were identified in the Phase 1 report, and to begin to implement the necessary rule changes and specifications of a new MMS's capabilities for the longer term changes which identified in this report. The specification of a new MMS should include a higher level formulation of the dispatch optimisation model and processes to ensure that effective co-optimisation of reserves and energy can be achieved and to ensure efficient treatment of constraint violations and market re-runs.

⁵ It should be noted that we have not factored in the cost of AGC connection for market participants or the benefits from greater utilisation of the transmission system resulting from the user of short-term thermal ratings in thermal network security limits.



In this report, we have also identified a number of enhancements to the Grid Code and approach taken by the SO in undertaking system operations. Our recommendation in this regard is for the enhancements to be considered as part of a revised Grid Code and for system operation procedures to be enhanced accordingly.



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1 Introduction

The Philippine Electricity Market Corporation (PEMC) commissioned Intelligent Energy Systems Pty Ltd (IES), in association with SW Advisory and Dr. Ross Baldick, to undertake a design study of the Philippines' Wholesale Electricity Spot Market (WESM).

The overall aim of the study was to address several market design and implementation issues, which are undermining the efficiency of the WESM, that were identified in the first Market Operations Audit⁶ undertaken by Deloitte and IES and in the second audit⁷ undertaken by PA Consulting.

1.1 Market Operational Audits

As part of the governance process, the PEM Audit Committee (PAC) conducts periodic market audits under the supervision of the DOE. In the 1st and 2nd Market Operations Audits, the External Auditors identified a number of market issues concerning technical aspects of the market such as the use of generator minimum stable loading parameters (Pmin) and the must offer rule, the choice of Constraint Violation Coefficients (CVCs), use of must run units (MRUs) and the prevalence of pricing error notices (PENs) that undermine the efficiency of the WESM.

PA Consulting's report for Market Audit No. 2 states:

There are deficiencies in the current market design that are directly related to non-compliance with the Rules setting out the purpose and objectives of the WESM as envisaged in Rules 1.2.2 and 1.2.5. Specifically:

- The Rules and Procedures around mandatory dispatching of generators at their Pmin level causes generators to be non-compliant with the "must-offer" rule (Rule 3.5.5.1). Furthermore, it is inconsistent with the principles of economically efficient dispatch and promoting competition.
- The Procedures around pricing errors and market reruns should be reviewed:
 - *The high number of pricing errors is due to the SO's requirement to use contingency constraints at the boundary between the market and MERALCO. This overly constrains the interface and produces problems. PA believes there are solutions available to address this issue. However, because there are three parties involved (PEMC, SO and the lines owner), it will take some time to get consensus on the most appropriate solution.*
 - *Furthermore, the decision to ignore constraint violation penalties and rerun the market may be inconsistent with market objectives related to economic efficiency and transparency.*
- The management of must-run-units by the SO is out of scope of this audit, as it involves assessing decision making made by the SO. However, we note that the

⁶ First Audit: Deloitte and IES "Philippine Electricity Market Corporation Independent Spot Market Audit Report1 on the Systems and Procedures of Market Operations", July 2010.

⁷ Second Audit: PA Consulting Group "Philippine Electricity Market Corporation Process Review: Independent Operational Audit of the Systems and Procedures on Market Operations", 26 August 2011.



decision to nominate MRUs is somewhat opaque and has the potential to significantly distort market outcomes.

As part of the Deloitte and IES Market Operational Audit, some attention was focussed on “Better Practices”. The “Better Practices” section of the audit was concerned with identifying opportunities to improve the transparency and efficiency of the WESM. The following opportunities to improve the WESM design and implementation were identified:

- improvements to the management of Pmin;
- improvements to systems and procedures for market re-runs and PENs;
- shortening the dispatch interval;
- reducing the gate closure time;
- implementation of a reserve market through the co-optimisation of energy and reserves;
- improvements to Market Dispatch Optimisation Model (MDOM) functionality and flexibility;
- improvements to the Market Network Model (MNM) with the inclusion of key parts of MERALCO’s sub-transmission to improve the efficiency of market dispatches and prices; and
- improvements to the provision of market information such as running the day ahead projection (DAP) on an hourly basis with price and dispatch sensitivities for material changes in demands.

1.2 Market Design Study Phase 2 Terms of Reference

The Market Design Study Terms of Reference (ToR) were aimed at addressing a number of the issues identified in the Market Audit reports.

Phase 2 of the WESM market design study was concerned with assessing the feasibility and approach for implementation for reducing the WESM’s trading interval to be less than one hour.

Specifically PEMC’s ToR for the WESM Design Study Phase 2 were:

The Consultant shall provide technical assistance in assessing the feasibility of shortening of the one hour trading interval in the WESM and provide advice and recommendations on the appropriate implementation scheme. The Consultant is also expected to:

- Recommend an appropriate dispatch interval to be used; Determine whether the distinction between ex-ante and ex-post prices could be removed; and*
- Determine associate changes to the overall market design upon shortening of trading interval.*

For each of the phases, the Consultant shall provide the following services:

- 1. Assess the feasibility of options or solutions identified;*



2. *Provide appropriate recommendations to address the market issues;*
3. *Provide simulations, impact analysis and other measurable basis/proof to support recommendations;*
4. *Identify and draft Rules and Market Manual changes, if any, to effect the proposed recommendations;*
5. *Provide the necessary reports, studies and documentations;*
6. *Present the results of the study to PEMC, DOE and ERC, or as required, to the PEM Committees; and*
7. *Act as expert witness, as required, during Regulatory hearings.*

1.3 Approach to Phase 2

The general approach we adopted for Phase 2 was similar to that taken in Phase 1. In particular:

- we reviewed material supplied by PEMC and the System Operator (SO) regarding the issues;
- we had meetings, workshops and consultations with PEMC, the SO, Distribution Utilities (DUs), generators, Grid Management Committee (GMC), Electricity Regulatory Commission (ERC), Department of Energy (DOE) and other stakeholders to discuss the key issues concerning the study and to set out our proposed enhancements to the WESM;
- we collected feedback on our proposed enhancements and rule changes from the stakeholders and have refined our recommendations and analyses to address the issues and concerns raised;
- we collected and analysed market data, provided by PEMC and the SO, on dispatch, 1-minute SCADA measurements, operation of MRUs and information on ancillary service providers etc. in order to better understand the issues concerning a shorter trading interval;
- from our analyses we assessed the market outcomes as to what could reasonably be expected in an efficient market and with what we have observed in other similar markets;
- from our analyses and existing suggestions for changes in market design or implementation we developed a set of options or proposed changes to the WESM;
- we analysed these options in terms of the impacts on market efficiency and transparency; and
- based on our analysis of the options we made recommendations and conclusions.

This report can be considered to be a more detailed assessment of the general recommendation made in Phase 1 to introduce a shorter dispatch interval in the WESM. As such this report ties together the recommendations made in Phase 1 and combines them with additional recommendations that arise when considering the introduction of a shorter dispatch interval.



1.4 Phase 2 Report Structure

This report is structured as follows:

- Section 2 provides a general background around the principles and design choices for the WESM, this is important as it guides the evaluation of market design options;
- Section 3 reviews the areas of WESM Rules and market operations that would be affected by a shorter dispatch interval;
- Section 4 reviews the aspects of system operations that would be impacted or that could be improved by having a shorter dispatch interval;
- Section 5 discusses the implications of a shorter dispatch interval for the management of ancillary services;
- Section 6 provides a more detailed analysis into the impact that a shorter dispatch interval would have on the frequency regulation requirement;
- Section 7 sets out a number of issues that a shorter dispatch interval could have on the operations of market participants;
- Section 8 sets out a number of issues that would need to be addressed in terms of the logical market interfaces;
- Section 9 reviews the impact on the IT systems of the MO, SO and market participants;
- Section 10 summarises the main enhancement options that have arisen from a consideration as part of introducing a shorter dispatch interval;
- Section 11 evaluates the options and sets forth a package of WESM enhancements some of which could be implemented immediately, while others need a new or substantially enhanced MMS, for completeness we include the recommended enhancements from Phase 1;
- Section 12 sets out the cost-benefit analysis from the Phase 1 report, refined to include the additional costs and benefits identified during Phase 2;
- Section 13 sets out the conclusions for Phase 2; and
- Annex A sets out a revised version of the WESM Rules, Chapter 3, reflective of the recommendations made in Phase 1 and Phase 2.

1.5 Conventions

In this report we have adopted the following conventions:

- References to the WESM Rules correspond to the “unofficial” WESM Rules that includes the amendments made to the rules as of December 2012.
- References to the Grid Code correspond to “Philippine Grid Code: Amendment No. 1”, April 2, 2007, drafted by Grid Management Committee and approved by Energy Regulatory Commission.
- We frequently refer to a “shorter dispatch interval”. When using this term, we generally have in mind a dispatch interval that is no greater than 15 minutes. Most of our examples are based on a 5-minute dispatch as this is the shortest dispatch interval that could be practicably implemented in the WESM at this stage given the



broader IT infrastructure that is in place. We will see later, that a dispatch interval of duration greater than 15-minute but less than 1-hour is unlikely to yield the same benefits as a shorter dispatch interval that would justify moving from 1 hour trading interval.



2 WESM Principles and Design

2.1 Introduction

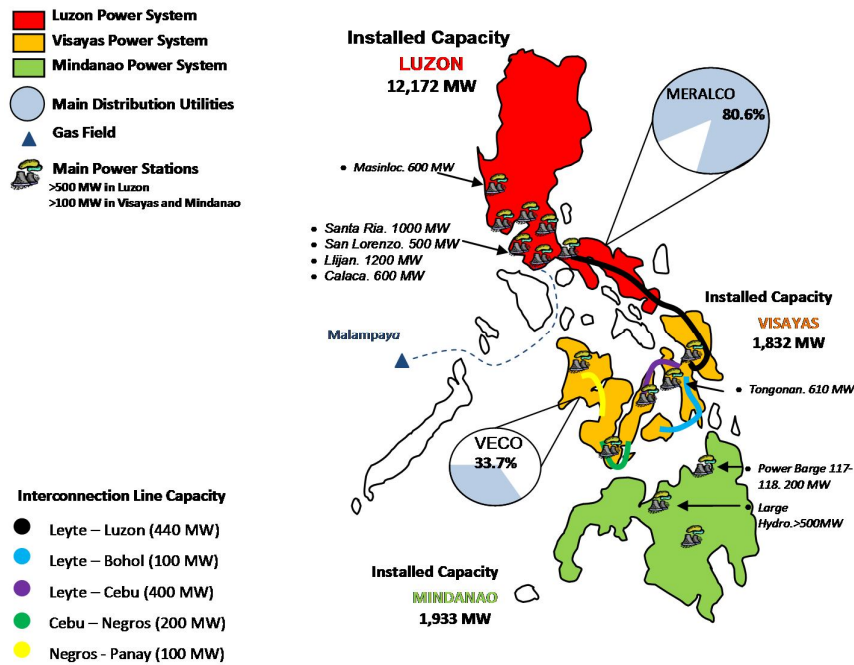
The Electric Power Industry Reform Act of 2001 (EPIRA) and its Implementing Rules and Regulations (IRR) form the framework for power industry reforms in the Philippines. EPIRA establishes the industry structure and measures to achieve reform objectives including the regulatory framework, restructuring of the power sector, private sector participation, development of competitive power markets and open access to gradually introduce retail competition. EPIRA was established to increase efficiency, enhance investment, broaden ownership, and encourage competition in the power sector and to provide for the orderly and transparent privatisation of the assets and liabilities of the Philippines National Power Corporation (NPC).

EPIRA mandated the establishment of the Wholesale Electricity Spot Market (WESM) and provides the broad parameters for its operation. The details of the WESM's operation are defined in the WESM Rules. The WESM Rules set out the design principles of the electricity spot market, roles and responsibilities of the Market Operator (MO) and the SO, governance of the market, registration of market participants, the procedures for dispatch and pricing, settlements and provision of information and processes for rules changes, disputes and enforcement.

The overriding aim of the WESM is to provide transparent and efficient dispatch and pricing, create incentives for efficient and competitive market outcomes and supply power in a reliable manner.

Figure 1 shows a stylistic representation of the Philippines Electricity Industry. The WESM commenced commercial operation in Luzon only on 26 June 2006, and as of 26 December 2010, Visayas joined the WESM.



Figure 1 Philippines electricity industry

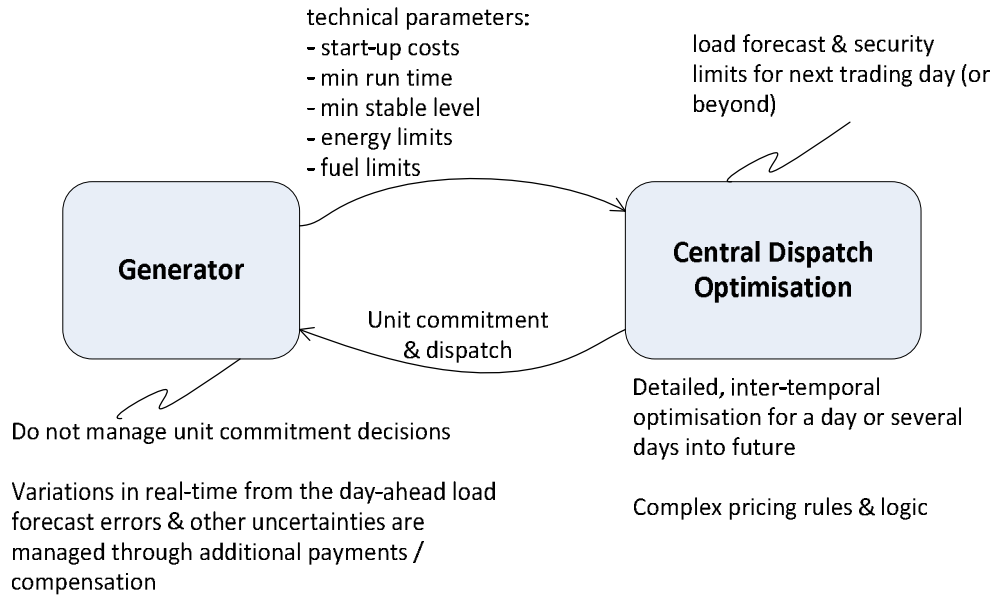
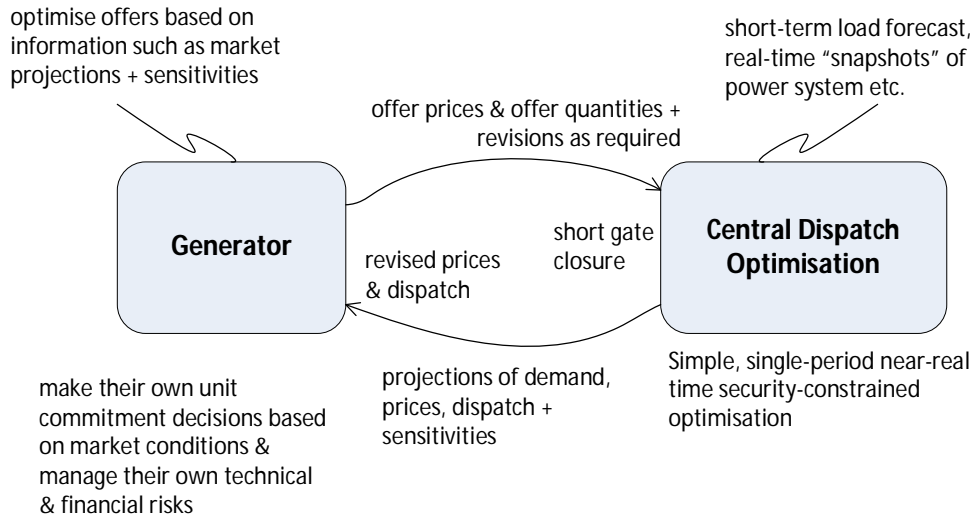
2.2 Governance and Management of the WESM

Under the supervision of the Department of Energy (DOE), the Philippine Electricity Market Corporation (PEMC) has been managing and governing the overall commercial operations of the WESM since 26 June 2006 for the Luzon grid and 26 December 2010 for the Visayas grid.

Policy and regulatory oversight functions over the WESM are performed by the DOE and the Energy Regulatory Commission (ERC). The DOE formulates and provides the country's overall energy policy, including evolution of WESM design. The ERC possesses authority extending from the enforcement of the rules and regulations of the EPIRA to investigative and quasi-judicial powers against any industry participant for violations of any law, rule or regulation.

2.3 Centralised and Decentralised Electricity Markets

Broadly electricity markets can be categorised into those that adopt a centralised philosophy, as illustrated in Figure 2, and those that adopt a decentralised philosophy, as illustrated in Figure 3.

Figure 2 Centralised electricity market design**Figure 3 Decentralised electricity market design**

The main characteristics of a centralised electricity market are:

- Generators provide detailed technical data on their plant to the MO on a day-ahead basis, such as start-up costs, start-up times, minimum run-times, ramping limits, minimum stable levels and so on, so that the market operator can determine day-ahead dispatch and unit commitment;

- The MO implements an inter-temporal (and often complex) centralised dispatch for a period of at least 1 day for the next day of market operations in order to determine plant commitment decisions and dispatch schedules; and
- Pricing and settlement rules are established to combine the outcomes of a day-ahead unit commitment optimisation with the outcomes of a shorter-term balancing mechanism with the purpose of reconciling differences between day-ahead operations and real-time operations (for example constrained-on and constrained-off payments).

For a centralised electricity market to operate efficiently, it is necessary for the centralised optimisation to satisfactorily represent all of the technical and operational issues that generators participating in the market may need to manage and ensure there are appropriate measures in place for the management and reconciliation of differences between day-ahead operations and real-time operations.

The main characteristics of a decentralised electricity market are:

- Generators are responsible for the management of their plant technical operations, unit commitment decisions and other market risks through generation offers submitted to the MO;
- The central dispatch optimisation is usually a single-period optimisation and usually determines commercially binding prices and dispatches for the next trading interval; and
- The MO often provides generators with projections of market prices, demand and dispatch outcomes to assist generators in managing the operations of their plant and other risks.

In order for a decentralised electricity market to operate efficiently, it is necessary – at a minimum – for:

- The MO to provide generators with regularly updated information on projected prices, dispatch and other market outcomes to ensure they can make informed commercial and technical decisions;
- Generators to have the flexibility in being able to revise their generation offers in response to changes in market conditions and/or the conditions of the equipment they operate;
- The market interface is appropriate to enable generators to represent their technical capability and commercial preferences; and
- The interfaces between SO, MO and market participants to be well-defined and allow for timely transfer of information that is needed to manage power system security, market outcomes etc.

2.4 Market Operations and System Operations

In the Philippines WESM the market operator (MO) and system operator (SO) are separate entities. The MO's role and responsibilities are defined in the Market Rules, while the SO's role and responsibilities are set out in the Grid Code. For a long dispatch interval (1-hour or more), compared to a shorter dispatch interval (5-minutes to 10-



minutes), the SO needs to address a greater number of issues to ensure that the power system is operated within a secure state and to ensure supply and demand are balanced.

As a dispatch interval is shortened, the electricity market is able to address a greater number of issues directly, in particular, the energy market is able to perform a greater amount of load following and also ensure that the power system is operated within a security envelope defined by the SO. The interface between MO and SO therefore needs to ensure that the SO is able to manage more of their operations “via the market”. In particular, it needs to be designed to ensure that the SO is able to advise the MO of appropriate security constraints, ancillary service requirements and/or any intervention actions that need to be taken in order to maintain the power system in a secure state. In order for this to be done effectively it is important to ensure consistency between the Grid Code and the Market Rules. Consequently, our discussion of the shorter dispatch interval necessarily requires consideration not only of market operations, but also system operations and the Grid Code.

2.5 WESM Design Philosophy

The intended WESM design as specified in the WESM Rules is that of a decentralised electricity market with the following being its key design features:

- it is an energy-only gross pool, that is there are no capacity payments and generators are expected to recover their costs through the energy market⁸;
- the MO can net out standardised bilateral contracts⁹;
- the dispatch interval is one hour;
- unit commitment decisions are decentralised;
- dispatch and prices are determined from an optimisation which is run every hour;
- spot prices are computed at each node (locational marginal pricing market);
- an ex-ante and ex-post pricing methodology is implemented to account for discrepancies between planned (ex-ante) and actual outcomes (ex-post):
 - generators are paid at the ex-ante price for their ex-ante scheduled generation and their deviations of actual generation versus the ex-ante generation are paid at the ex-post price and there is a similar arrangement for loads;
- the market is of a decentralised design in that generators are responsible for self-commitment decisions and need to manage any fuel or energy limitations via their offers and changes to their offers subject to gate closure of 1 hour ahead of the real-time;
- there is not a market price cap or floor but there is a bid cap (or offer price ceiling) of 62,000 P/MWh which is currently imposed on participants;

⁸ Even though the WESM is designed for both energy and reserves to be priced through the spot market, based on generator offers, demand bids and demand forecasts, this would still be classified as an energy only market because there are no capacity payments.

⁹ The combined financial impact of PEMC netting out bilateral contracts in the WESM from participants' spot market payments combined with bilateral contract payments is that the cash flows correspond to ordinary spot market payments, standard two way contract for difference (CfD) payments plus payments for line rentals based on nodal price differences. Thus it would be quite possible to extend the netting out process to include other contract types such as one way CfDs.



- the market rules provide for the development of a financial transmission rights (FTR) regime but this has not been implemented;
- the rules provide for a reserve spot market to manage the markets regulation and contingency reserve requirements; and
- the WESM currently covers the grids of Luzon and Visayas, but not Mindanao.

PEMC ensures the optimal dispatch of generation based on the submitted offers from generators and bids from customers, and from which locational spot prices for electricity throughout the grid are set. It also facilitates the settlement of financial accounts of the trading participants.



3 Market Operations

3.1 Introduction

When considering a shorter dispatch interval, there will be implications for a number of aspects of market operations. In this section we review the WESM Rules and present approach taken for market operations in order to identify:

- issues that would need to be addressed if a shorter dispatch interval were to be implemented; and
- opportunities to enhance the WESM.

3.2 Trading Intervals and Dispatch Intervals

The WESM Rules defines a market trading interval of 1 hour as follows:

3.4.1.1 For the purpose of trading in energy and ancillary services, [a] trading interval [is] one (1) hour, commencing on the hour.

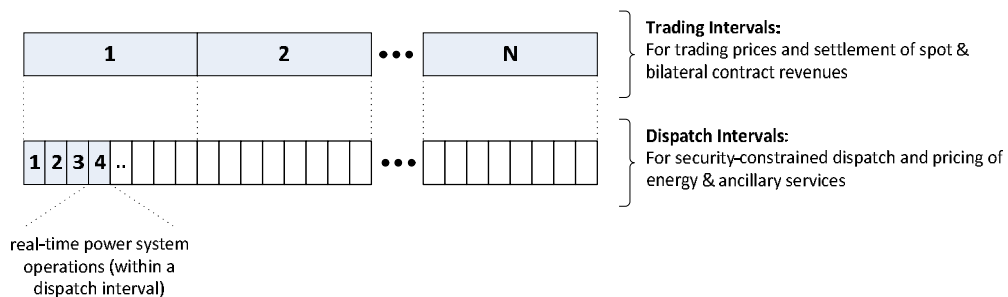
That is, there is presently no distinction between a trading interval and a dispatch interval. However, this need not be the case. An electricity market can be designed so that the dispatch and pricing occurs on a relatively short duration while settlements can be based on trading intervals of longer duration and that are aligned with the existing infrastructure for energy metering and forms of electricity contracts.

For a shorter dispatch interval in the WESM, it is recommended that a distinction be made between trading intervals and dispatch intervals, with definitions as follows:

- a *trading interval* to be the period of time used for performing settlements based on metered energy and trading prices; and
- a *dispatch interval* to be the period of time that is used for physically dispatching and pricing resources in the electricity market.

There should be an integer number of dispatch intervals for each trading interval. The dispatch intervals are used for dispatching generation and loads, while the trading intervals are used for energy settlements, as well as the day ahead projection (DAP) and week ahead projection (WAP). We illustrate the concepts of trading intervals, dispatch intervals and real-time operations in Figure 4.

Figure 4 Trading intervals, dispatch intervals and real-time operations



In the WESM a shorter dispatch interval could be introduced without changing the existing systems that compute hourly settlements, the infrastructure for energy metering or any of the existing bilateral contracts entered into by market participants. The only issue that needs to be addressed is to define trading interval prices for each MTN based on dispatch and pricing outcomes of the corresponding set of shorter dispatch intervals.

It is useful to also define power system operations occurring within a *dispatch interval* as “real-time operations” (see Figure 4). This may include second-by-second Automatic Generation Control¹⁰ (AGC) for frequency regulation, governor responses of generators following the sudden failure of a generator, the activation of load shedding schemes and other control actions necessary to maintain the power system in a secure state.

3.3 Nodal Energy Trading Prices

For a shorter dispatch interval, prices will be determined for each dispatch interval. However, for the purpose of settlement it is necessary to establish nodal energy trading prices based on nodal energy dispatch interval prices (and other outcomes).

The two main options that could be considered for defining the nodal energy trading prices (ETPs) are:

- ETP at an MTN is defined to be the generation or load weighted average of the corresponding nodal energy prices for the set of dispatch intervals within the given trading interval; or
- ETP at an MTN is defined to be the average (“time-weighted average”) of the corresponding nodal energy prices for the set of dispatch intervals within the given trading interval.

Given the WESM is based on a nodal market where each unit or power station has its own separate MTN, then the first of these options will provide a reasonable approximation of what the generator’s revenue would have been had settlement been performed on a shorter dispatch interval (5-minutes say).

To demonstrate this is the case, firstly note that the ETP at each generator MTN would be:

$$ETP(j) = \text{sum} \{ EDP(j, t) \times G(j, t) \} / \text{sum} \{ G(j, t) \}$$

where $ETP(j)$ is the Energy Trading Price at node j , $EDP(j, t)$ is the Energy Dispatch Price at node j for dispatch interval t , $G(j, t)$ is the SCADA-measured generation for node j and dispatch interval t (for example, from the 5-minute SCADA snapshot files that the SO sends to the MO).

The actual spot revenues for the generator at node j would be determined on a trading interval basis of 1-hour, and would be computed as:

$$R = ETP(j) \times MQ^*(j)$$

¹⁰ 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 frequency limits or both.



where R is the spot revenue of a generator at node j , $MQ(j)$ is the metered quantity of generation at node j .

If we then compute the revenue, we find:

$$\begin{aligned} R &= ETP(j) \times MQ(j) \\ &= [\text{sum}\{ EDP(j,t) \times G(j,t) \} / \text{sum}\{ G(j,t) \}] \times MQ(j) \end{aligned}$$

Since $MQ(j) \approx \text{sum}\{ G(j,t) \} \times Td$, this is approximately equal to¹¹:

$$\begin{aligned} R &\approx [\text{sum}\{ EDP(j,t) \times G(j,t) \} / \text{sum}\{ G(j,t) \}] \times \text{sum}\{ G(j,t) \} \times Td \\ &= \text{sum}\{ EDP(j,t) \times G(j,t) \} \times Td \end{aligned}$$

where Td = duration of a dispatch interval (in hours)¹². This illustrates that the generator will be paid approximately what they would have been paid if the market was settled on a dispatch interval basis.

It can be readily demonstrated that the use of a time-weighted average does not result in this outcome and introduces an inconsistency between dispatch and pricing, which could introduce undesirable incentives, particularly for flexible generators capable of starting-up at short notice (on a sub trading interval basis).

A potential variation on the concept of using generation and load weighted average pricing approach would be to replace the 5-minute snapshots with an estimate of generated (or consumed) energy based on SCADA data by integrating the 2-second MW SCADA generation (or load) measurements over the dispatch interval and these estimates as the basis of the weighting, rather than 5-minute snapshots. This could be expected to improve the accuracy of the approximation of metered energy in the determination of generation / load weighted energy trading prices.

Irrespective of the approach adopted, the trading interval prices should be clearly published to enable market participants to settle any derivative contracts that have not been declared to the MO. Also note that participants could also write contracts to be settled outside the MO's systems based on dispatch interval prices if they so desired, and so the corresponding set of nodal dispatch prices should also be published for this purpose as well as for reasons of market transparency.

3.4 Ex-Ante Pricing and Ex-Post Pricing

The WESM is based on ex-ante and ex-post pricing which appears to have been put into place to address having a dispatch interval of 1 hour:

- the “ex-ante” dispatch and pricing are both based on the same optimisation, utilising ex-ante information regarding load, transmission, ramping, and generator offers (which also reflect their plant availability); and

¹¹ Note that there may be a need to adjust the SCADA-measurement, $G(j,t)$ by a Site-Specific Loss Adjustment Factor (SSLA), or equivalent, in order to align metered quantities with SCADA measured generation quantities. This detail is not explicitly included in the formula.

¹² This is required to adjust for the fact that a dispatch interval's duration is less than 1 hour.



- in order to discipline discrepancies between planned and actual outcomes, prices are also determined “ex-post” and applied to that discrepancy.

This process encourages predictable behaviour by participants by rewarding the provision of reliable information and reinforcing the penalties imposed on participants who are found to have misled the market¹³.

If the dispatch interval were to be reduced from 1 hour, then ex-ante dispatch and pricing will be updated more frequently, based on more accurate demand forecasts and snapshots of the present state of the power system. Participants will also have a reduced window in which to deviate from their dispatch instructions. Introducing a shorter dispatch interval therefore reduces the need for ex-post pricing but settlements based on ex post metered quantities would still continue.

For a dispatch interval of 5-minutes to 10-minutes, we suggest that the WESM only requires ex-ante pricing with settlements being based on ex-ante prices and actual measured outcomes; the ex-ante schedules would not be used in market settlements (see section 3.5). For a 5-minute dispatch interval¹⁴, we would expect that the next 5-minute ex-ante price is similar to ex-post price for the previous 5-minutes, since it will be based on current information about loads, available units and other system conditions, only they are forward-looking to the next dispatch interval, rather than back 5-minutes.

As proposed in the previous section, the hourly ETP (nodal energy trading price) at a generator's node would be the generation weighted average of the 5-minute dispatch prices based on actual SCADA snapshot measurements of 5-minute generation outputs. For spot market settlements based on ex-ante only pricing, ETP will be multiplied by the generator's metered generation for the hour. The product will be very close to the sum of the five minute ex-ante prices times the metered generation energy quantities measured over the 5-minute period if this were measured. This in turn will be extremely close to the sum of the 5-minute ex-post prices multiplied by the 5-minute metered generation quantities, which is what would be used in the calculation of an ex post settlement.

Because the combination of a trading interval price based on a generation weighted price based on SCADA data and the use of metered hourly data for settlements, the use of ex-ante pricing as proposed will also be very close to a 5-minute ex-post pricing proposal. There should not be much difference between the two, other than that the ex-ante version would allow both loads and non-centrally dispatched generators to know the price before the dispatch interval. Thus there is no need to retain an ex-post price with a short dispatch interval as the ex post circumstances are captured in the next 5-minute dispatch interval. If a generator does not generate to the level that it was dispatched to in a 5-minute dispatch interval this will be reflected in its generation weighted trading interval price.

¹³ PHB Hagler Bailly Asia Pacific Limited and Freehill Hollingdale & Page “Discussion Paper on the Proposed Market Design & Governance Structure for the Philippines Wholesale Electricity Market” Prepared for Department Of Energy, Energy Regulatory Board, National Power Corporation, 2001.

¹⁴ Note that the same argument for a 5-minute dispatch interval would apply to a 10-minute dispatch interval.



Following this logic, in terms of incentives for market participants to follow their dispatch instructions, roughly the incentives of a market that implements a shorter dispatch interval, with ex-ante only pricing and generation or load weighted energy trading prices, would be better or similar to those of a market with a longer dispatch interval that maintained the ex-post pricing logic presently in the WESM. Additional incentives for generators to follow their targets (per se) would come from having automated rules for detecting and managing non-conformance or allocating costs of providing regulation based on deviations.

It should be noted that procedures for handling the situation when SCADA data is unavailable or there is a SCADA systems failure need to be carefully considered. We provide a discussion of this issue in section 8.9.

3.5 Energy Settlements

Presently, in the WESM the settlement of energy for each market trading node and trading interval is specified in WESM Rules section 3.13.8 and 3.13.9:

3.13.8 Determining the Ex-ante Energy Trading Amount

For settlement purposes, the ex-ante energy trading amount for each market trading node and trading interval will be determined as the ex-ante energy settlement price for that node in that trading interval multiplied by the ex-ante energy settlement quantity (in MWh) for that node in that trading interval.

3.13.9 Determining the Ex-post Energy Trading Amount

For settlement purposes, the ex-post energy trading amount for each market trading node and trading interval will be determined as:

(a) The ex-post energy settlement price for that node in that trading interval multiplied by the ex-post energy settlement quantity for that node in that trading interval (in MWh); minus (b) The ex-post energy settlement price for that node in that trading interval multiplied by the ex-ante energy settlement quantity for that node in that trading interval (in MWh).

Written algebraically, the current approach for energy settlements for a generator is:

$$TTA_{gen} = (EAQ - BCQ_{gen}) \times EAP_{gen} + (MQ_{gen} - EAQ_{gen}) \times EPP_{gen}$$

where TTA_{gen} = total trading amount for generator, EAQ_{gen} is ex-ante quantity, BCQ_{gen} is the total bilateral contract quantity declared for that generator, EAP_{gen} is the ex-ante trading price, MQ_{gen} is the metered generation, and EPP_{gen} is the ex-post trading price.

The present settlement for energy for a customer is similar:

$$TTA_{load} = (EAQ_{load} - BCQ_{load}) \times EAP_{load} + (MQ_{load} - EAQ_{load}) \times EPP_{load} + LR$$

where BCQ_{load} is the bilateral contract declared by the customer load and other symbols are defined similarly to the formula for the generator's trading amount. The only difference for a customer is the addition of line rental, LR , which (assuming just a single bilateral contract between a generator and a customer) is defined as:

$$LR = (EAP_{load} - EAP_{gen}) \times BCQ_x$$



where EAP_{load} is the ex-ante price at the customer's MTN, EAP_{gen} is the ex-ante price at the generator's MTN and BCQ_x is the bilateral contract quantity declared between the generator and customer.

Under a shorter dispatch interval we propose to remove the concept of ex-post pricing and ex-post energy settlements (based on the arguments given in section 3.4) but maintain the concept of netting out declared BCQs. For a generator the total trading amount for energy becomes:

$$TTA = (MQ - BCQ_{gen}) \times ETP$$

where ETP is the nodal energy trading price defined in section 3.3, and for a customer it becomes:

$$TTA = (MQ - BCQ_{load}) \times ETP + LR$$

where $LR = (ETP_{load} - ETP_{gen}) \times BCQ_{load}$.

In terms of implementation based on the existing systems, all that would be required would be to set the ex-post prices to zero, compute the trading interval prices based on the SCADA snapshots and feed these numbers into the existing settlement system.

Presently, non-scheduled and renewable energy (RE) generators are paid based on ex-post prices and metered energy as they are not centrally dispatched. If the WESM was to use ex-ante only pricing, then these generators would have their settlements based on ex-ante prices and metered energy, consistent with the approach set out above, as per all other market participants.

3.6 Market-Based Ancillary Service Pricing and Settlements

Under the Pricing and Cost Recovery Mechanism for Reserves¹⁵ (PCRM), payments for ancillary services are proposed to be based on ex-ante prices and quantities. As the issue of energy metering, settlement systems and bilateral contracts does not apply to the ancillary service market, under a shorter dispatch interval, the settlements of ancillary services can be based directly on the dispatch prices and quantities. So payments would be determined as:

$$ASP[g,s,t] = ASDP[g,s,t] \times ASQ[g,s,t] \times Td$$

where $ASP[g,s,t]$ is the payment to generator g , for service s in dispatch interval t , $ASDP[g,s,t]$ is the ancillary service dispatch interval price and $ASQ[g,s,t]$ is the MW quantity of service s that was determined for generator g in dispatch interval t . This is essentially the same as the approach taken in the Australian National Electricity Market (ANEM).

While the dispatch, pricing and settlement of ancillary services would occur on a dispatch interval basis, for information we recommend production of regional trading interval ancillary service prices, which would be defined as the requirement-weighted dispatch interval ancillary service prices. Furthermore, ancillary service payments can be

¹⁵ Note that a more detailed discussion of the proposed ancillary service market arrangements is given in section 5.2.



aggregated into hourly payments to be consistent with the approach taken for energy settlements. To enhance transparency, the underlying dispatch interval ancillary service prices, requirements and quantities should be published.

For the purposes of clarity we will refer to the dispatched quantities of ancillary services (contingency reserves and regulation) as enabled quantities. If a generator or load is enabled for a contingency reserve or regulation it does not mean that it will actually generate that amount, it just means that if circumstance require it then it might be called on to generate that amount. For instance a 200 MW generator could be dispatched for 100 MW of energy and enabled for 100 MW of contingency reserve. In this case, most of the time the generator will just generate 100 MW. However in the event of a contingency like a generator failure the unit would be expected to generate 100 MW for energy and 100 MW for the enabled (dispatched) contingency reserve, giving a total of 200 MW of generation at the end of the dispatch interval.

The proposed ancillary services cost recovery arrangements are based on the following principles:

- cost recovery on a reserve cost recovery zone;
- allocation of the costs for each service for each cost recovery zone to loads and generators based on pre-determined factors; and
- costs allocated on a MWh basis using the ex-ante dispatches and load forecasts.

Introducing a shorter dispatch interval does not require this logic to be materially revisited, although some refinements to regulation cost recovery could be introduced to provide greater incentives for generators to conform to their dispatch instructions and to go on AGC. For example, the cost of regulation could be apportioned to the generators and loads that have driven the need for frequency regulation by deviating from their schedules. An additional refinement would be to exempt any generators that are on AGC from making regulation payments – creating an incentive for generators to go on AGC. We discuss this further in sections 4.3 (benefits of having more generators on AGC), 5.6 (incentives for generators to provide ancillary services) and 7.8 (incentives for generators to follow dispatch instructions). An additional enhancement would be to base cost allocations on actual (metered) outcomes, rather than on ex-ante dispatches and load forecasts.

Irrespective of the approach taken, the cost allocation for ancillary services should be performed directly based on the dispatch and pricing outcomes for all ancillary service categories and all ancillary service trading amounts. These could be aggregated to on an hourly trading interval basis to ensure consistency between energy settlements and ancillary service settlements.

3.7 Gate Closure

Gate closure is the time before the start of a dispatch period after which changes to bids are not reflected in dispatch and pricing. In the WESM gate closure is set to 1 hour, which means that generators are effectively unable to respond to market conditions and change their dispatch levels for nearly 2 hours.



A shorter dispatch interval means that prices and dispatches will be updated more frequently to reflect present system conditions. If gate closure is not reduced accordingly, then it will inhibit the ability of generators to manage their technical and commercial risks. This includes generators making unit commitment decisions, managing their Pmins or hydros managing small storages. This is even more the case when there is an ancillary services market since market participants will be trading not only in energy, but also in numerous ancillary services which all need to be jointly managed based on the technical capability of their generators to provide ancillary services.

Therefore the gate closure needs to be reduced as part of reducing the shorter dispatch interval duration, with the best approach being to not have gate closure at all. For the latter, it would mean that the effective gate closure would be related to the point in time ahead of the next dispatch interval when the market clearing engine starts solving. For example, it may be say 10-seconds or 30-seconds ahead. Once the market clearing engine's processing commences, any bids and offers that are received after this point in time would not have any impact on the outcomes of the next dispatch interval. They would only have an impact on the following dispatch interval. The "remove gate closure" proposal would therefore still mean there is an "effective gate closure", but it would be related to the speed with which the market management systems could process any changes to an offer and the time ahead of the next dispatch interval the market clearing engine process starts to solve. This should be less than a minute.

3.8 Market Processes and Market Timetable

Table 1 summarises the key WESM market processes that are presently in place.

Table 1 Summary of WESM market processes in presently in place

Market process	Frequency	Horizon	Periodicity
RTD (ex-ante dispatch)	1-hour	1-hour ahead	1 hour
RTX (ex-post dispatch)	1-hour	1-hour behind	1 hour
DAP (day-ahead projection)	4-hours	Up to 24-hours ahead	1 hour
WAP (week-ahead projection)	Daily	Up to 1-week ahead	1 hour

The existing DAP process has a number of limitations. Firstly, it is executed only every 4 hours, which is too infrequent for generators that have short start-up times and for providing information on changes to system conditions – the state of the power system could change considerably over a period of 4 hours. Secondly, the horizon is "up to 24 hours ahead", so as the trading day proceeds, the look-ahead becomes increasingly myopic. A third issue with the DAP process is that it only executes a single scenario, which for some participants is insufficient to make "robust" commitment and other decisions.

To improve the DAP the following recommendations were made in the Phase 1 report:

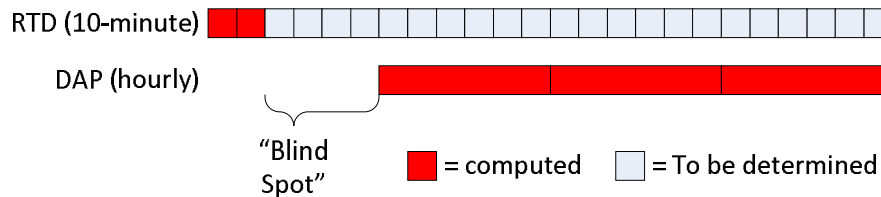
- execute DAP on an hourly basis;



- extend the DAP period to always be at least 24 hours ahead; and
- execute the DAP for multiple scenarios (have a number of high and low demand sensitivities).

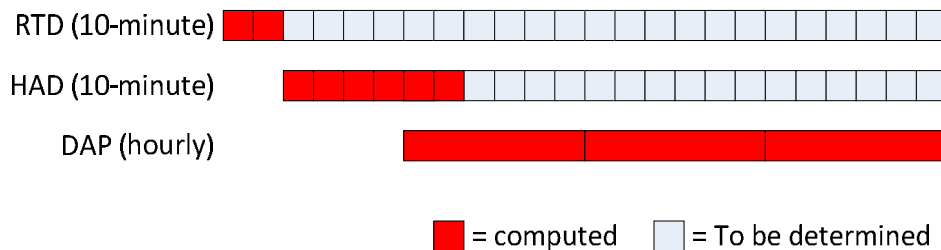
However, if a shorter dispatch interval were to be introduced then for generators to make well-informed technical and commercial decisions related to their operations, for example, hydro plants managing small / limited storages, fast-start plant deciding whether to start-up then these DAP enhancements may still not provide sufficient information for some generators. For the purposes of illustration, if the dispatch interval were reduced to say 10-minutes then there would be a period of up to 1-hour for which the market participant has no forward information. For example, Figure 5 illustrates how there is the potential for a “blind spot” between the present (RTD) dispatch interval and the first trading period of the DAP.

Figure 5 DAP and RTD for a shorter dispatch interval



To address this, we propose to augment the RTD with an “hour ahead dispatch” (HAD), which would fill in the gap (or “blind spot”) between RTD and DAP. The HAD process would essentially extend the RTD process into the future for a 1 hour period, with the same resolution as the RTD process (5-minutes or 10-minutes). The concept and horizon of HAD is illustrated in Figure 6. The HAD process would facilitate generators in making short-term decisions and provides a short-term assessment of market outcomes. Generator decisions on timescales of 1-hour or more, can be made based on the enhanced DAP process.

Figure 6 DAP, RTD and proposed HAD process



The main benefits that HAD would introduce are as follows:

- In Phase 1, we recommended setting Pmin constraints in the market dispatch optimisation model to zero. Units concerned about being dispatched between 0 and their minimum stable level could monitor the outcomes of HAD and adjust their generation offers accordingly should they have an undesirable dispatch level in a

dispatch interval (note that for this to be effective, it would be necessary to effectively remove gate closure);

- Facilitate fast-start units in monitoring the need to commence the process of starting-up; and
- Allow any small reservoir hydro generators to better manage their reservoirs over the next hour.

Table 2 sets out the proposed market processes and their main features. One issue that will need some attention is to ensure there is consistency between demand projections used in the HAD and DAP processes. We propose that the RTD and HAD demand forecasts be based on nodal (MTN) demand forecasts based on a bottom up approach set out in section 3.9. The DAP is presently based on the Similar Day Load Forecasting (SDLF) methodology, which is an example of a top-down forecast. The first 1 to 2 hours of the DAP could be based on a nodal time series estimation approach that is similar, but which just operates on an hourly basis. This could then revert back to the SDLF approach from 2 hours onward. Importantly, some research into the most effective approach should be conducted¹⁶. Note that the DAP itself is able to overcome demand forecast uncertainties, to some extent, by executing demand sensitivities.

Table 2 Proposed market processes and their main features

Process	Frequency	Look-Ahead	Interval	Sensitivities
Real-time Dispatch (RTD)	5-minutes	n/a	5-minutes	n/a
Hour Ahead Dispatch (HAD)	5-minutes	1 hour ¹⁷	5-minutes	Optional ¹⁸
Day Ahead Dispatch (DAP)	1-hour	24 hours	1-hour	Yes

3.9 Management of Constraint Violations

A shorter dispatch interval increases the importance of ensuring that the dispatch and pricing optimisation always delivers a physically feasible dispatch solution to the SO and commercially binding prices to market participants. Implementing the automatic handling of constraint violations is therefore a pre-requisite to a shorter dispatch interval and would be required in the RTD, HAD, DAP and WAP processes. The Phase 1 report provides the details of the approach that could be taken.

3.10 Demand Forecasting

Presently, the MO produces hourly demand forecasts for the market processes as summarised in Table 3.

¹⁶ Note that PEMC has conducted an internal study on how to improve the accuracy of the nodal demand forecasting in the WESM: "Nodal Forecasting in the Philippines Wholesale Electricity Spot Market", December 2012. This paper sets out a number of ways to improve the accuracy of demand forecasts in the WESM.

¹⁷ Note that 1 hour would probably be sufficient, provided the DAP is executed on an hourly basis, for longer than 1-hour, it would be necessary to consider an alternative demand forecasting technique compared to the use of a simple time series as proposed in section 3.9.

¹⁸ A high / low case may be useful, however, if DAP sensitivities were computed, then the market participant should have enough information on projected outcomes to manage their decisions.



Table 3 Summary of WESM demand forecasts

Demand forecast	Frequency	Horizon	Approach	Periodicity
Hour-Ahead (RTD)	1-hour	1-hour ahead	Internally developed hour-ahead projection	1 hour
Day-Ahead (DAP)	4-hour	Up to 24-hours ahead	Similar Day Demand Forecast	1 hour
Week-Ahead (WAP)	1-Day	Up to 1-week ahead	Similar Day Demand Forecast	1 hour

The present approach used for hour-ahead demand forecasts is based on a methodology that PEMC has developed internally, which overrides the results of the demand forecasts of the MMS in order to improve their accuracy. Essentially, a regional hour-ahead demand projection is developed based on measurements (5-minute SCADA snapshots) of demand 5-minutes ahead of the current trading interval, the present conditions (primarily climate conditions) and adjusted for previous errors. For example, if the demand forecast for the 13:00 target hour would be determined at 11:55. The measured demand levels at each MTN are then used to apportion the regional-level (Luzon and Visayas) hour-ahead demand projection to be on a nodal (MTN) basis.

The DAP and WAP methodology is based on the Similar Day Load Forecast (SDLF) approach. Regional forecasts are produced and it is disaggregated to the individual market trading nodes (MTNs) based on load distribution factors.

By introducing a shorter dispatch interval, it will be possible to introduce short-term demand forecasts for each MTN that should be more accurate than the present approach. This is because for a shorter dispatch interval there will be less demand uncertainty (see section 6) and since they will be done on a nodal basis the need to disaggregate the regional forecast is avoided. For example, a simple statistical time series or regression model could be introduced that utilises information such as:

- snapshots of the demand at the individual MTNs;
- demand from a set of previous dispatch intervals, for example, the previous dispatch interval, the same dispatch interval for yesterday, the dispatch interval for the week before; and
- other variables that influence demand such as temperature, humidity etc.

A 5-minute ahead demand forecast model may take the following form:

$$\begin{aligned}
 D(t+5 \text{ minutes}) = & a + b_1 D(t) + b_2 D(t-5 \text{ minutes}) \\
 & + b_3 D(t+5 \text{ minutes} - 1 \text{ day}) + b_4 D(t-1 \text{ day}) \\
 & + b_5 D(t+5 \text{ minutes} - 7 \text{ days}) + b_6 D(t-7 \text{ days})
 \end{aligned}$$

Such a model is likely to perform better for shorter term forecasts such as those less than 15 minutes ahead. This is for a number of reasons. Firstly, the model will use the current status of the system which will reflect prevailing weather and any other factors that



influence demand. Secondly, such a model would be calibrated on a nodal basis which would reflect the unique characteristics of each load at each MTN, for example, flat industrial loads vs. temperature-sensitive residential or commercial loads. As PEMC has collected a large volume of 5-minute SCADA data on demand, it would be possible to conduct some research into calibrating these models and assessing their accuracy.

The improvement in forecast errors for shorter dispatch intervals should result in a reduction of the amount of regulation reserves required to manage the power system within the WESM's (Grid Code's) frequency standards. We examine this in more detail in the section 6.

3.11 Summary of Proposed Market Operation Enhancements

In summary the following proposals are suggested to enhance the market operations in the WESM:

- Adopt a scheme of *dispatch intervals* and *trading intervals*, where there is an integer number of *dispatch intervals* per *trading interval*. The dispatch intervals are used for dispatching generation and loads and the trading intervals are used for energy settlements and day ahead and week ahead projections.
- Adopt a scheme of *dispatch interval nodal prices* and *trading interval nodal prices* for energy. The *trading interval nodal price* for a *market trading node* is the generation weighted or load weighted average of the corresponding *dispatch interval nodal prices* for that *market trading node*.
- Adopt a scheme of *dispatch interval regional prices* and *trading interval regional prices* for reserves. The *trading interval reserve price* for a *region* and *reserve category* is the regional requirement weighted average of the corresponding *dispatch interval regional reserve prices* for that *reserve category*.
- Adopt *ex-ante* pricing for energy and reserves. The *ex-ante* nodal energy price for each market trading node in any dispatch interval reflects the marginal costs of supply or in cases of supply shortage, the market price cap or in cases of excess supply, the market price floor (see Phase 1). The marginal cost of supply is determined from the shadow price of the energy balance equation or equivalent from the market dispatch optimisation model.
- The *ex-ante* regional reserve dispatch price for each market reserve region in each dispatch interval reflects the marginal costs of supply and is determined from the shadow price of the relevant reserve requirement constraint or equivalent from the market dispatch optimisation model.
- Settlements for energy are based on ex-ante nodal energy trading prices and metered energy quantities for all market participants (scheduled and non-scheduled).
- Ancillary service settlements based on dispatch interval prices and quantities. For consistency with market settlements for energy, they could be aggregated on an hourly basis.



- Shorten gate closure to say 30 seconds before the start of the next dispatch interval (essentially limit gate closure to the time at which the market clearing engine commences solving).
- Enhance the DAP process as follows (refer to Phase 1 report):
 - execute DAP hourly;
 - extend horizon to always be at least 24-hours ahead;
 - introduce a number of demand sensitivities;
- Introduce a HAD process as a 1-hour extension of the RTD with periodicity equal to that used for a shorter dispatch interval;
- Automate the management of constraint violations in RTD, HAD, DAP and WAP (refer to Phase 1 report); and
- Enhance the approach for short term demand forecasting to use nodal-based forecasts using a simple time series model. We make the observation that some research based on historical 5-minute SCADA snapshot data could be undertaken in order to determine the most appropriate time series model, calibrate them and assess their accuracy.

These would largely need to be implemented as changes to the Market Rules and the associated Market Procedures, particularly the Dispatch Protocol Manual.



4 System Operations

4.1 Introduction

The WESM Rules 3.8.2 set out the SO's responsibilities as they pertain to dispatching and generally managing power system security in the WESM:

3.8.2 Responsibilities of the System operator

3.8.2.1 During each trading interval, the System operator shall use its reasonable endeavors to: (a) Implement the dispatch targets determined by the Market Operator, (b) Maintain system security consistent with the requirements of the Grid Code; (c) Implement load shedding, if necessary, as provided by clause 3.9; and (d) Intervene, where necessary, as provided by clauses 6.3 and 6.5.

3.8.2.2 After each trading interval, in accordance with the timetable, the System operator shall advise the Market Operator of: (a) Situations in which it became necessary for dispatch instructions to deviate from the dispatch targets determined by the Market Operator during the trading interval; (b) Load shedding or other directions issued by the System operator during the trading interval; (c) Significant incidents in which contingency reserve was called upon during the trading interval; (d) Network constraints which affected dispatch during the trading interval; (e) Binding security constraints which affected dispatch during the trading interval; and (f) Operational irregularities arising during the trading interval including but not limited to any circumstances in which there was prima facie evidence of a failure to follow dispatch instructions.

A shorter dispatch interval means that more of the SO's actions presently taken within an hour will need to instead be directly managed via the market's dispatch and pricing process. This generally enhances transparency and results in a greater focus on the impact that SO operations have on market dispatch and pricing outcomes. While the SO continues to be responsible for ensuring the power system is operated in a secure state, the means by which it is achieved changes from intervening directly to advising the MO of changed conditions, new security constraints or the need for calling plant as must-run.

This section reviews the existing approach for grid operations and power system security management, with a view to identifying WESM enhancement options that come about from a shorter dispatch interval for evaluating later.

4.2 Dispatch Instructions and the Merit Order Table (MOT)

The SO is responsible for issuing dispatch targets to the generators under WESM Rule 3.8.3:

3.8.3 Communication of target loading levels

The System operator shall communicate the target loading levels to Trading Participants for each trading interval prior to the commencement



of that trading interval in accordance with the timetable and consistent with the Grid Code.

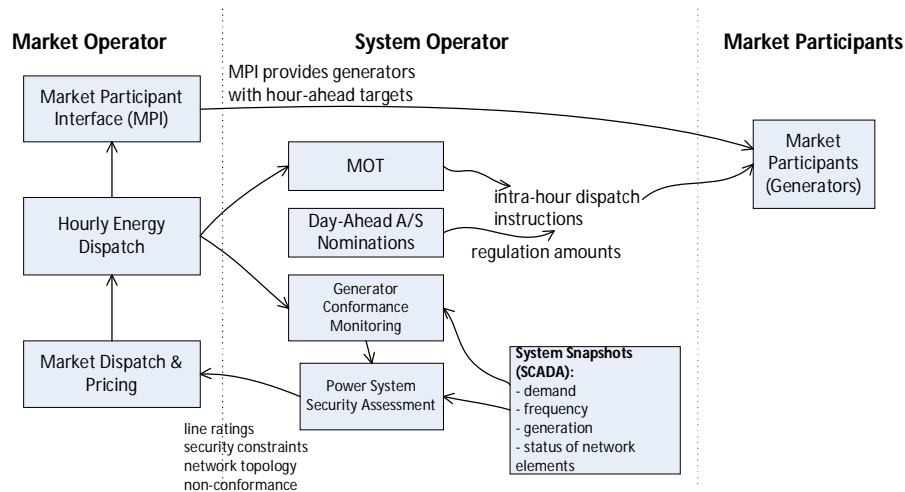
Figure 7 summarises the present way in which dispatch instructions are presently issued to generators, based on the Grid Code and dispatch protocol¹⁹.

The main features of the existing arrangements are as follows:

- for the hour-ahead, the MO provides the SO with the energy dispatch targets for all generators and the MOT;
- the SO uses this combined with the present demand levels, present generator outputs levels and the results of the day-ahead ancillary service nominations process (for regulation) to determine intra-hour dispatch instructions for the generators; and
- the generators also receive their hour-ahead dispatch via the MPI, which they are required to follow linearly from one period to the next, but subject to any overriding instructions that may be issued by the SO.

The SO also monitors conformance of generators to their dispatch instructions, which we discuss in more detail in section 4.7.

Figure 7 Existing approach for issuing dispatch instructions



The MOT does not account for any technical constraints such as the (technical) Pmins of generators, transmission limits or other network security limits. These issues can be quite significant and are difficult to manage on an ad-hoc basis as changes in conditions within a 1-hour period can be significant. For example, Figure 8 shows the daily demand profile in Luzon for 17 January 2013 based on 1-minute SCADA snapshot data. It can be seen that some 1-hour trading intervals experience significant variations in demand, for example, the 3-hour period from 4pm to 7pm, as illustrated in Figure 9. As illustrated in Figure 10, when there are large deviations in demand, there can be periods of time when it is difficult to ensure the power system is being operated in a secure state.

¹⁹ PEMC, "WESM Manual: Dispatch Protocol Issue 7.0", 26 March 2013.

Figure 8 Luzon demand profile on 17 January 2013 based on 1-minute SCADA snapshots

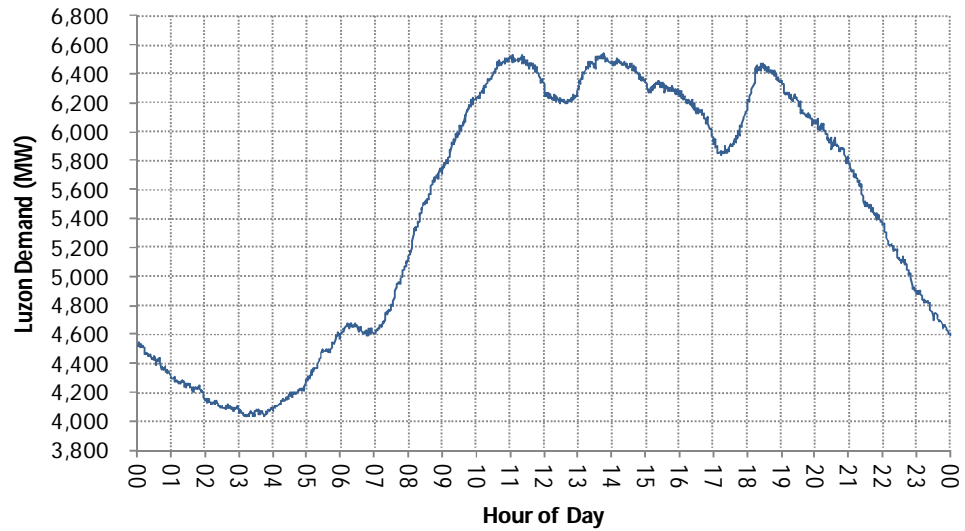


Figure 9 Luzon demand for 17 January 2013 from 16:00 to 19:00

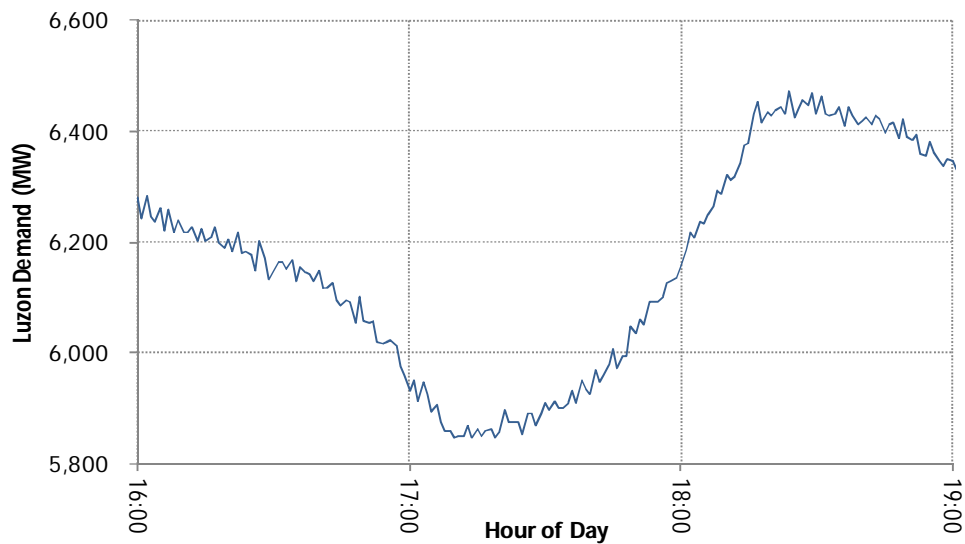
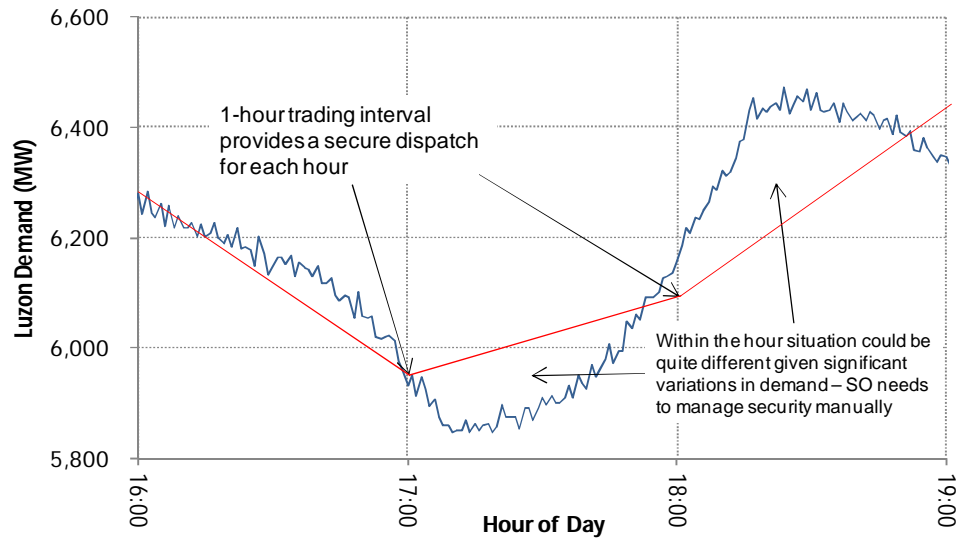
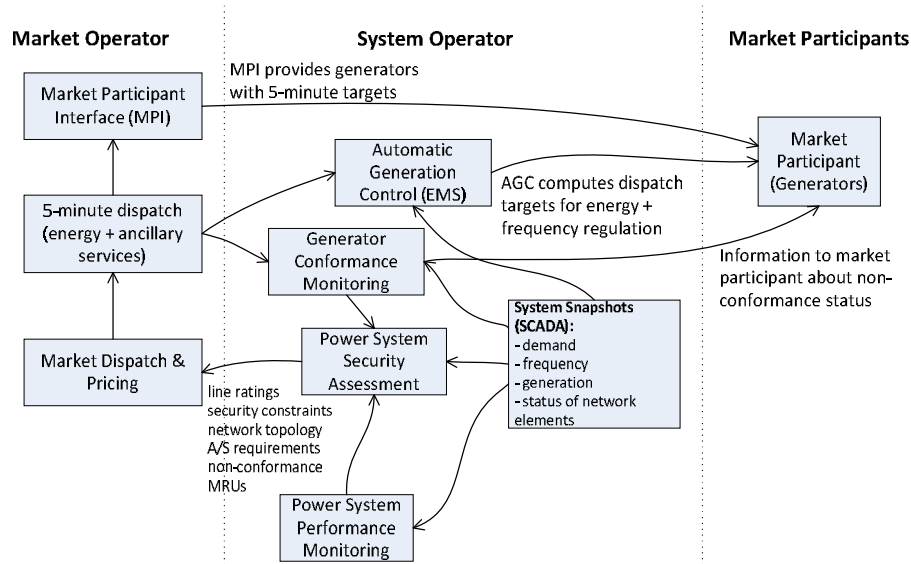


Figure 10 Management of security within the hour

If a shorter dispatch period (one that is less than 15 minutes) were to be introduced, the MOT could be removed altogether. This is because the market dispatch will be updated sufficiently frequently to reflect the present state of the power system, including any security constraints that the system operator may require and generators will be able to actively managing their Pmins²⁰. Under this scenario, the SO does not need to be concerned with actively dispatching generators; instead they can primarily be concerned with monitoring generator conformance to market dispatches.

The approach that could be adopted is illustrated in a stylised manner in Figure 11 for a 5-minute dispatch interval.

²⁰ It is assumed that the recommendation made in the Phase 1 report of setting Pmin = 0 is adopted.

Figure 11 Shorter dispatch interval approach for issuing dispatch Instructions

The diagram illustrates how:

- generators may obtain their 5-minute energy and ancillary service targets from the MPI and are responsible for directly implementing them, otherwise they would be directly interfaced to the SO's AGC system (discussed further in the next section);
- the SO's AGC system is set up so that:
 - for energy, it provides generators with a smooth trajectory from their present output level to the target that the market has determined for the next dispatch interval; and
 - for frequency regulation, the AGC is configured so that over the 5-minute period, the generator's participation factors reflect the outcomes of the 5-minute market-based dispatch of regulation services;
- the full set of 5-minute generator targets for energy and ancillary services would be delivered to the SO to automatically monitor for dispatch instruction conformance (discussed further in section 4.8);
- the SO will need to advise the MO of:
 - changes to the network topology (done via snapshot files);
 - any changes to the transmission line short-term or continuous ratings (could be done via snapshot files);
 - whether any additional security constraints are required;
 - declaration of any MRUs and the appropriate means by which they are to be managed in the market (see section 4.7);
 - whether any previously specified security constraints can be relaxed;
 - ancillary service requirements (see section 5); and

- whether any generators are identified to be non-conforming, as well as any remedial action that should be taken; for example fixing the generator's target to a previously measured value or imposing some security constraint on the generator (see section 4.8).

For this to be successful, a number of changes to the SO's AGC would need to be implemented. These are detailed in the next section.

4.3 Automatic Generation Control (AGC)

For a shorter dispatch interval, to better automate the transfer of dispatch targets to market participants, the SO's AGC could be enhanced as follows:

- interface the AGC directly to the outputs of the market dispatch process;
- refine the AGC's control scheme logic to provide appropriate dispatch instructions to generators; and
- interface generator control systems to the SO's AGC.

We set out the details of how the AGC logic could be enhanced in section 8.3, as part of the discussion of the interface between the SO, MO and market participants.

At this time only a small number of generators²¹ are presently connected to the SO's AGC, which presents a barrier to more efficient operation of generators in the WESM. Having most generators on AGC has benefits for both the WESM and for the generators. For the WESM, the benefits are as follows:

- Increased competition to provide frequency regulation services;
- Ensures generators will be able to more accurately follow their market-determine schedules, hence less need for provision of frequency regulation services; and
- Reduced need for intervention from the SO.

The benefits to market participants of being on AGC include:

- Reduced need for actively monitoring the MPI to determine dispatch targets;
- Being able to participate in the frequency regulation market; and
- Reduced likelihood of non-conformance.

We therefore propose that in the Grid Code, AGC be made mandatory for all generators that exceed say 30 MW (or another suitably chosen threshold) and that are centrally dispatched. An alternative would be to charge generators not on AGC, a SO management fee sufficiently high to encourage all generators that can cost effectively move to AGC to do so. An additional incentive for encouraging generators to go on AGC would be to allocate the costs of regulation to customers and generators that are not on AGC.

4.4 Power System States

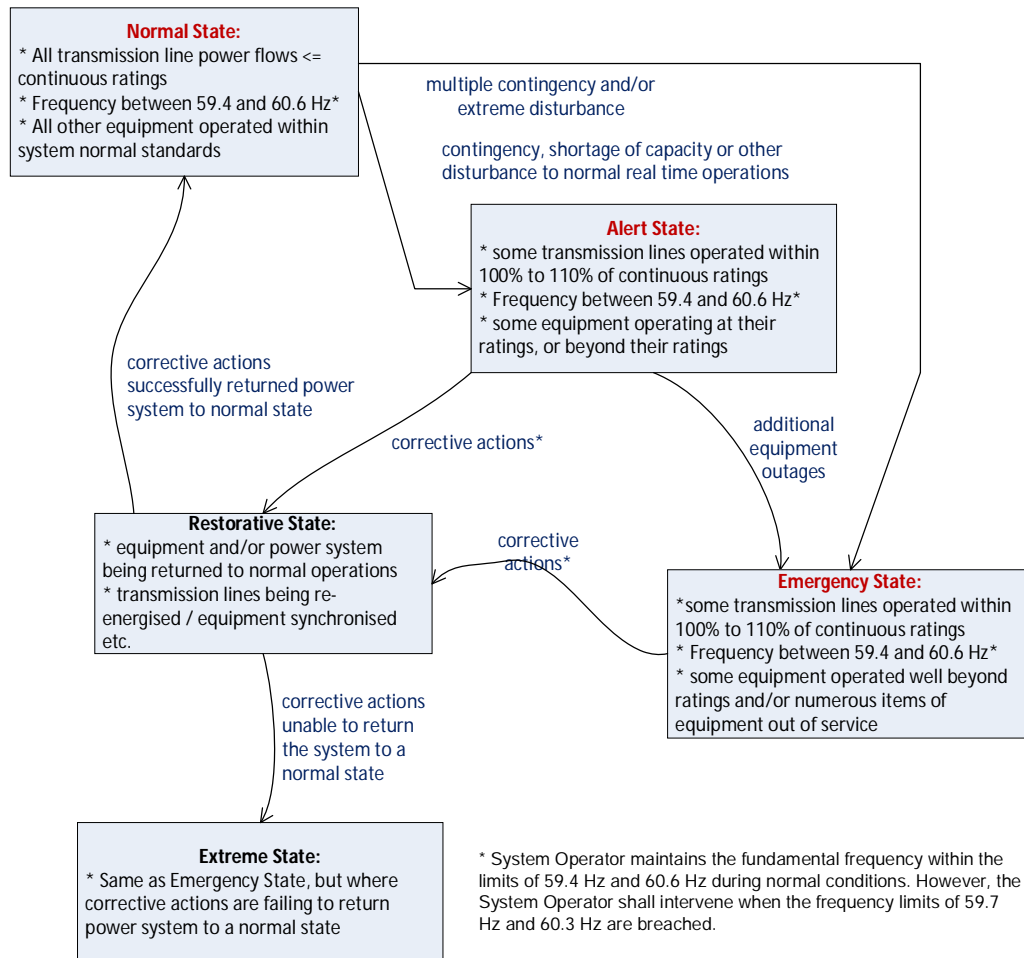
The concept and power system states as defined in section 7.2 of the Grid Code is illustrated graphically in Figure 12. Generally, to ensure reliability, security and quality of electricity, the SO is required to maintain the power system in the normal state. In the

²¹ The only generators connected to AGC are those that presently provide frequency regulation ancillary services.



normal state, all power system equipment is operated within the desired standards and/or bounds specified in the Grid Code. When contingencies occur, the power system may transition outside the normal state, whereupon the SO needs to take corrective actions to return the power system back to the normal state.

Figure 12 Grid operating states²² based on Grid Code



The standards that apply to thermal overloading and frequency standards when the power system is in the various states are as follows²³:

- Standards for the thermal loading of transmission lines as a function of the power system state are as follows:

²² Note that while we have highlighted the state of transmission lines and frequency standards in this diagram; similar issues apply to operating reserves and voltage levels.

²³ We focus on thermal overloading and frequency standards in this report as these are the immediate areas that can benefit from a shorter dispatch interval. The management of voltage security, reactive power and avoiding power system instability are also likely to benefit from a shorter dispatch interval, but we do not discuss them in this report.

- *Normal state.* The transmission lines are to be operated within 100% of their continuous ratings;
- *Alert state.* Some transmission lines operated at between 100% and 110% of their continuous ratings. No transmission lines operated beyond 110% of their continuous ratings;
- *Emergency state.* Some transmission lines may be operated beyond 110% of their continuous ratings; and
- The frequency standard (59.4 – 60.6 Hz) does not change as a function of the power system state (the frequency for system normal conditions applies equally to the alert state and emergency state).

For a shorter dispatch interval (15-minutes or less), the following benefits can be gained:

- Between the different operating states there could be significant changes to the network topology owing to the failure of transmission elements or generators. Furthermore, the system operator in the Alert or Emergency states will likely be intervening significantly. If a shorter dispatch interval is in place, and the state of the network²⁴ is automatically fed through to the market dispatch and pricing process, then the MO will be able to deliver to the SO a secure dispatch shortly following the occurrence of contingencies, which should minimise the need for the SO's discretion and manual intervention and consequently reduces the likelihood of needing to suspend the market.
- Post-contingent transmission line power flows, are presently bounded by the continuous transmission line ratings in MDOM. They could instead be bounded by the short-term thermal ratings of the transmission lines. This will allow for greater use of the transmission network without compromising power system security. We illustrate this in section 4.5.
- We observe that the frequency standards do not change between the different power system states and are specified deterministically. An alternative approach could be used where:
 - frequency standards are specified in a probabilistic manner, for example frequency within bounds 99% of the time;
 - use of the wider frequency bands for the alert and/or emergency states compared to the normal state, for example, in the system normal state, require a tighter range of frequency so that following a contingency there is less risk that the power system will enter into a state of frequency collapse, say for example, when the power system is in a normal state, the frequency standard could be ²⁵: 59.8 and 60.2 Hz;
 - the need to return frequency back to the normal state following a contingency within a prescribed period of time (for example, 10 minutes following a contingency, system frequency is to return to the system normal state);

²⁴ This would include for example the transmission elements in and/or out of service and the dynamic ratings of the transmission lines.

²⁵ This is strictly just an example – the SO would need to conduct an investigation into what is an appropriate and acceptable range for system normal conditions.



- This enables ancillary service reserve requirements to be computed directly based on the standards and the categories of ancillary service to be more tightly linked to the power system standards. Approaches for setting requirements of contingency reserves and regulation reserves in this way are described further in section 5.5 and 6.

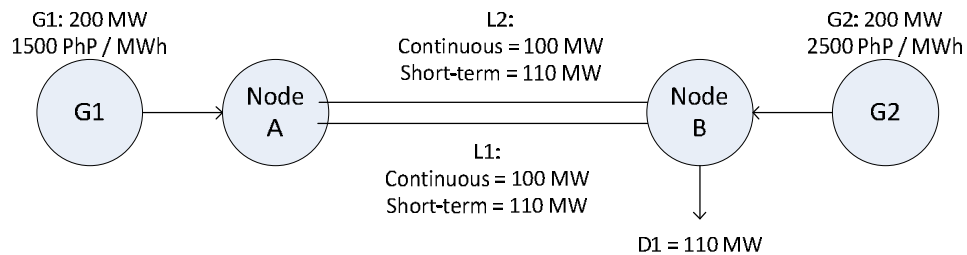
These are some refinements that could be considered as part of implementing a shorter dispatch interval in the WESM. These enhancements would require some revisions to the Grid Code.

4.5 Transmission Line Ratings

Usually thermal limits on transmission lines are used in thermal security constraints to avoid having pre-contingency and post-contingency transmission line flows overloading a transmission line. An approach that could be introduced in the WESM to better utilise the transmission network would be to use short-term thermal ratings of the transmission lines to manage post-contingency transmission flow limits. This can only really be leveraged if the dispatch interval was to be shortened to less than about 15 minutes.

To illustrate how this works, it is easy to use an example. Consider the simple network that is illustrated in Figure 13

Figure 13 Example transmission network



In the example network:

- Generator 1 (G1) has capacity of 200 MW, a cost of 1500 PhP / MWh and is connected to node A;
- Generator 2 (G2) has capacity of 200 MW, a cost of 2500 PhP / MWh and is connected to node B;
- Line 1 and Line 2 are characterised by:
 - equal impedances and "lossless";
 - continuous rating of 100 MW;
 - short-term rating of 110 MW;
- The transmission lines can be safely operated at their short-term ratings without causing damage for 15 minutes; and
- Demand (D1) of 110 MW is located at node B (node A is assumed to not have any demand).

In general, a thermal security limit can be expressed in the following form²⁶:

$$|f_m + k_{m,n} \cdot f_n| \leq R_m$$

which would be in place to ensure that post-contingent power on line m does not exceed line m's rating, R_m , following the loss of line n. The $k_{m,n}$ value is a function of the network impedances and network topology and it indicates the proportion of flow from line n that will flow on line m, following the loss of line n.

We would like to compare two situations:

- Case 1. Dispatch of G1 and G2 where continuous ratings are used for all purposes, i.e. to manage pre-contingency and possible post-contingency power flows; and
- Case 2. Dispatch of G1 and G2 where the continuous ratings are used to manage pre-contingency flows and short-term ratings for possible post-contingency power flows.

In Case 1, the following constraints would be required to avoid thermal overloading:

$$|f_1 + f_2| \leq 100 \quad (\text{manage post contingent flows})$$

$$|f_1| \leq 100, \quad |f_2| \leq 100 \quad (\text{manage pre-contingent flows})$$

and G1 (being cheaper than G2) would be dispatched to 100 MW and G2 to 10 MW. Since the lines have equal impedance, 50 MW would flow on each from node A to node B. The situation is illustrated in Figure 14, which is the "pre-contingency state of the system". If line 2 was to fail, then it is clear, power flows on line 1 will not exceed the continuous ratings, as illustrated in Figure 15.

Figure 14 Case 1 pre-contingency dispatch and power flows

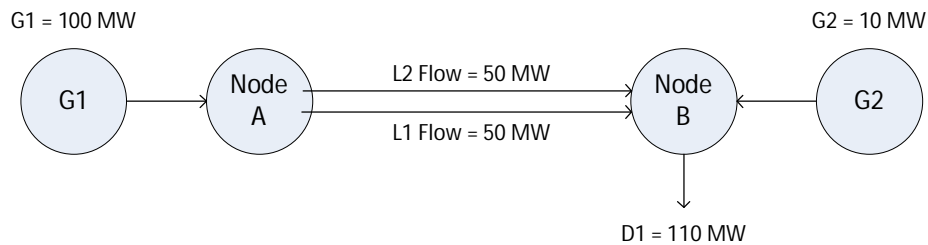
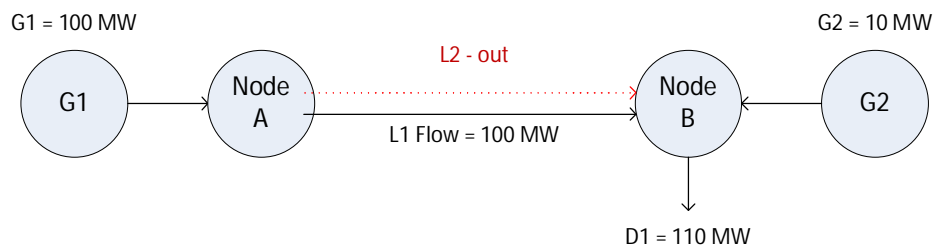


Figure 15 Case 1 post-contingency dispatch and power flows



²⁶ Note that we ignore safety margins in these examples.



In Case 2, the thermal overloading constraint is able to take advantage of short term thermal ratings:

$$|f_1 + f_2| \leq 110 \quad (\text{manage post contingent flow})$$

$$|f_1| \leq 100, \quad |f_2| \leq 100 \quad (\text{manage pre-contingent flows})$$

and G1 (being cheaper than G2) would be dispatched to 110 MW and G2 to 0 MW. Since the lines have equal impedance, 55 MW would flow on each from node A to node B. Figure 16 shows the pre-contingency network flows. This illustrates greater use of the transmission system with higher pre-contingency power flows on the transmission lines and reduced dispatch costs by avoiding the use of generator G2.

Figure 16 Case 2 pre-contingency dispatch and power flows

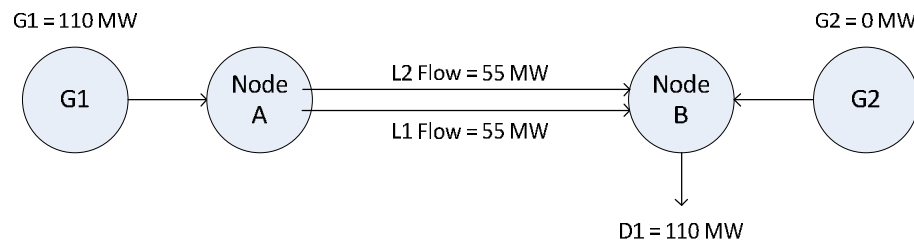
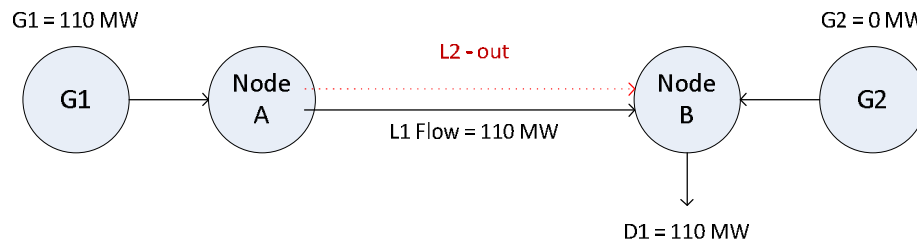


Figure 17 shows the post-contingency power flows following the loss of line 2. Clearly line 1 is now loaded at the short-term thermal rating. This is a situation that can only be sustained for a short period of time; 15 minutes in the case of this example. If the dispatch interval was say 5-minutes or 10-minutes, the thermal limits would be adjusted and power flows recomputed for the next dispatch interval so that thermal power system security would again be satisfied; i.e. it would take into account the change in network topology owing to the loss of line 2 and the fact that line 1 has been recently been operated at its short-term rating.

Figure 17 Case 2 post-contingency dispatch and power flows



This conceptually illustrates:

- greater utilisation of the network that is possible through the use of less conservative post-contingency security limits, which is possible for a shorter dispatch period; and

- the way in which, following a contingency, the dispatch and pricing can quickly be adjusted to reflect the system conditions, this removes discretionary decision-making by the SO and enables the market to continue operating even when the system is in the Alert or Emergency states.

Another benefit that can be captured is to utilise information on the dynamic ratings of transmission lines. The transmission line ratings are a function of ambient conditions and so it would be possible to make adjustments to the ratings used in thermal security limits to reflect the ambient conditions. This would avoid the need for the SO to err on the side of caution.

In order to implement this, the SO would need to advise the MO of the short-term thermal ratings for the transmission lines that need to be operated according to the N-1 criteria.

It should be noted that this is not to be confused with the System Preservation Scheme (SPS), which would enable certain transmission lines to be operated less conservatively as would be the case under the N-1 criteria as some portion of the demand at selected nodes will be curtailed in the event of a failure to prevent the transmission lines from being overloaded. However, the SO would need to advise the MO about these transmission lines, in real-time, as they will need to be treated in the dispatch and pricing formulation differently compared to non-SPS transmission lines.

4.6 Frequency Standards

The frequency standards are important because they form the basis of ancillary service requirements. In the WESM Grid Code, the SO is responsible for maintaining system frequency deviations to be within the frequency standards specified in the Grid Code²⁷:

3.2.2 Frequency Variations

3.2.2.2 The control of System frequency shall be the responsibility of the System Operator. The System Operator shall maintain the fundamental frequency within the limits of 59.7 Hz and 60.3 Hz during normal conditions.

We observed in section 4.4, that irrespective of the state of the power system, the frequency standard remains the same. Generally the system normal frequency standard is chosen to be sufficiently tight so that the power system can tolerate potentially large frequency excursions that occur following a credible contingency. If the system normal frequency standard is too relaxed, and the power system is operated close to the boundary of the range of allowed frequencies and there is a contingency, then frequency collapse could ensue. When the power system is in an alert or an emergency state, a more relaxed frequency standard (compared to the system normal standard) can generally be tolerated (since it is usually the occurrence of a contingency that leads to the system being operated in such a state). More relaxed standards may, for example, apply in the situation when the power system operates in an islanded state or it is in an

²⁷ Note that in other markets there is often a concept of normal, alert and emergency frequency standards; the Philippine Grid Code does not seem to have such a concept for system frequency.



emergency state due to other reasons. We also observed that the standards are deterministic and do not take into account the time spent in different power system states.

An example of a frequency standard that has a probabilistic basis (from the Australian market, where the nominal system frequency is 50 Hz) is given for the situation where the power system is fully connected and for the situation when the power system is operating as an electrical island. Figure 18 illustrates power system frequency, following the loss of a single generator unit, is maintained within the alternative frequency standard. The tight 49.9 to 50.1 Hz band is used to ensure that frequency is near normal prior to a contingency occurring and thus following a contingency the frequency does not go outside the post contingent frequency standards immediately following a contingency.

Table 4 Example of frequency standard for connected power system

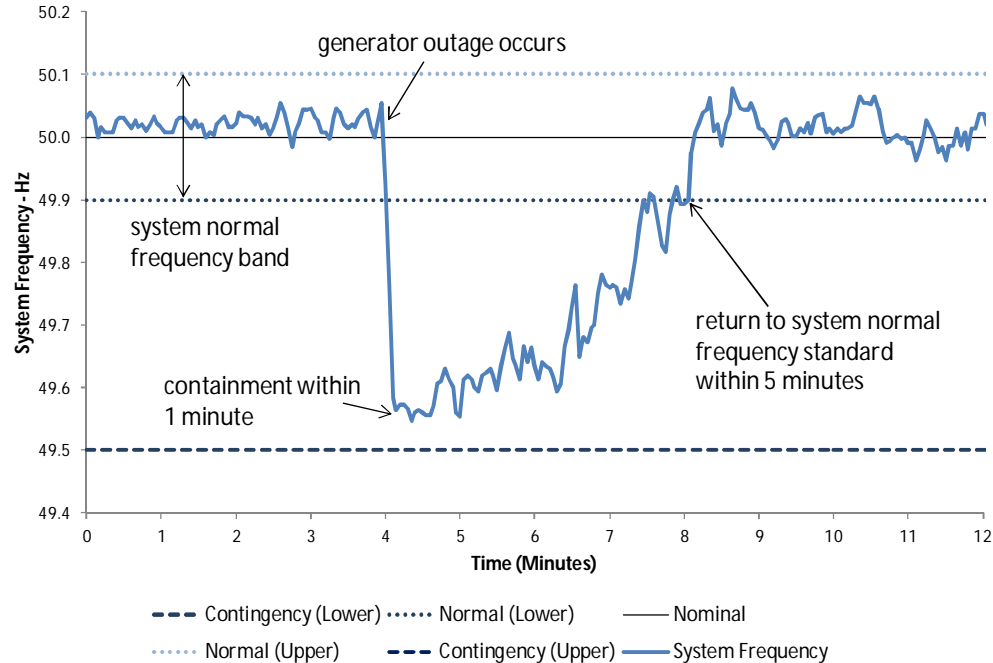
System Conditions	Containment	Stabilisation	Recovery
Normal	49.90 to 50.10 Hz		
Unplanned Load Change	49.75 to 50.25 Hz	49.9 to 50.1 Hz within 5-minutes	
Single generating unit loss	49.50 to 50.50 Hz		49.9 to 50.1 Hz within 5 minutes
Other single credible contingency event	49.00 to 51.00 Hz	49.5 to 50.5 Hz within 1 minute	49.9 to 50.1 Hz within 5 minutes
Multiple contingency event	47.00 – 52.00 Hz	49.5 to 50.5 Hz within 1 minute	49.9 to 50.1 Hz within 10 minutes

Table 5 Example of frequency standard for islanded power system

System Conditions	Containment	Stabilisation & Recovery
Normal	49 to 51 Hz	
Unplanned Load Change	49 to 51 Hz	
Single generating unit loss	49 to 51 Hz	
Other single credible contingency event	49 to 51 Hz	
Multiple contingency event	47 to 52 Hz	49 to 51 Hz within 1 minute



Figure 18 Illustration of system frequency management following generator outage



4.7 Management of MRUs

In the Phase 1 report we proposed that in order to improve the management and operation of MRUs in the WESM, any unit that has been directed to operate as a MRU, should be obliged to offer into the market to fulfil its MRU obligation. If there is any doubt that the generator might be dispatched as required, the SO could advise the MO of a fixed generation profile or lower and upper bound generation profiles as well.

For a shorter dispatch interval, any fast-start MRUs that would presently be called upon at short notice within a 1-hour period can instead be represented directly in the market clearing process at the next dispatch interval along with any appropriate adjustments to the dispatch of other generators²⁸. In this way, the shorter dispatch interval combined with improved arrangements for MRUs there will be greater transparency of “intra-hour” operations and the SO’s level of discretion will be reduced.

Further discussion on the management of MRUs was given in Section 7 of the Phase 1 report.

²⁸ This reduces discretion that is presently being exercised by the SO – for example, to avoid overloading a transmission line, sometimes the SO calls a unit as must run in a particular network location and will require other generators to “back-off”. This is necessary because of the 1-hour dispatch interval, however, for a shorter dispatch interval, the “backing off” will be done directly by the market clearing process and will take effect in the next dispatch interval.

4.8 Automated Conformance Monitoring System (ACMS)

In any electricity market, monitoring compliance of the operations of market participants is important as it creates an incentive for market participants to follow dispatch instructions and to ensure that they are able to provide ancillary service responses procured via the market when there is a power system event.

In the WESM, the concept of “Dispatch Tolerance” is defined in the WESM Rules as the extent to which a generator may deviate from its schedule:

3.8.7 Dispatch Tolerances

3.8.7.1 Dispatch tolerances shall be set to allow limits on the extent to which Trading Participants may deviate from dispatch targets issued by the System operator.

3.8.7.2 The Market Operator shall maintain and publish dispatch tolerances standards developed by the System operator for each type of plant, and location, in accordance with the Grid Code and Distribution Code.

Conformance is presently assessed on a trading interval basis and is the joint responsibility of MO and SO. Under a shorter dispatch interval, an automated conformance monitoring system (ACMS) should be introduced to assess conformance on a dispatch interval basis. Note however that non-conformance for a single dispatch period (of 5-minutes or 10-minutes) is not as much of an issue as compared to a generator that does not conform over a period of 1 hour and so the existing approach for conformance monitoring needs some refinements for a shorter dispatch interval. The implementation of market-based ancillary services also would require some enhancements.

The following are suggested refinements for ACMS implementation:

- The SO will need to ensure that it maintains records of dispatch instructions that are sent to generators, which could be defined as follows:
 - for generators on AGC, the SCADA/EMS can record them directly; or
 - for generators not on AGC, defined as the linear trajectory from one dispatch interval to the next;
- These would be provided as inputs into the ACMS along with:
 - the present set of schedules for energy and regulation services (for generators providing regulation) being determined by the market clearing process;
 - the measured output of each generator;
- The ACMS would incorporate a number of tests along the following lines:
 - large and small deviations from dispatch targets;
 - number of successive dispatch intervals for which non-conformance by small and/or large amounts was detected²⁹;

²⁹ For example, 3 dispatch periods for small deviations and 2 for large deviations. A large deviation may reflect issues such as a generator being dispatched between 0 and its P_{min}, a generator that has tripped or the situation



- generators operating between 0 and P_{min} ;
- It should notify participants and the MO of the ACMS status of each generator that is monitored for each dispatch period; and
- When non-conformers have been detected, then remedial actions may include:
 - constraining non-responsive generators to their previous SCADA-measured generation levels;
 - setting the generator's output level to a specific level (as may be advised by the participant);
 - removing them from the dispatch and pricing process (or setting their output level to zero);
 - manually dispatching the plant to market-based levels via telephone instruction; or
 - taking other intervention measures as required.

For transparency, the ACMS algorithm should be published.

Another aspect of operations that the SO will need to monitor will be the responses of generators that were enabled to provide ancillary services. This is to ensure those generators and loads enabled to provide responses actually provided them when the ancillary services were needed and that the responses were consistent with what was their energy market dispatch.

Monitoring conformance of frequency control ancillary service providers would need to be based on SCADA data and involves processing along the following lines:

- For frequency regulation services, conformance monitoring would involve checking to make sure that any generators with a non-zero MW quantity for frequency regulation are responding to signals from the AGC to regulate frequency³⁰. As shown in Figure 28 (see section 7.7), the AGC may require a generator to operate at any point within a "feasible space" which is a function of its market-determined frequency regulation MW quantity (or quantities³¹) and its energy schedule. Any generator that is being asked by the AGC to operate at a level within the feasible space, but which does not respond within a reasonable period of time³² could be assessed to be not following its AGC instructions to regulate frequency.
- Conformance monitoring for contingency reserve services can only be done when a frequency event has occurred (i.e. a contingency). This may not be very frequent. A possible approach would be as follows:
 - Detection of a contingency event (e.g. monitor power system frequency or check for large deviations in generation, loads, network power flows);
 - Check generator and load responses on the timescales relevant to the definitions of the ancillary services to ensure that each generator that had a non-zero

where the generator's communication network has failed and it is no longer receiving centrally determined dispatch targets.

³⁰ Refer to section 8.3.2 for more information on how AGC determines targets for generators taking into account the need to regulate system frequency.

³¹ In general, a generator may have a raise regulation MW quantity and a lower regulation MW quantity.

³² Note that a generator is unlikely to instantaneously track its AGC targets – there will be some lag.



ancillary service quantity actually responded to the level that was necessary to halt any frequency deviations and/or restore system frequency to the nominal frequency; and

- In situations where generators or loads do not provide appropriate or adequate ancillary service responses the SO can take remedial actions as follows:
 - adjusting the technical representation of the generators in the market dispatch optimisation process – for example, reducing the amount of capacity in the ancillary service categories they have found to not be able to provide adequately;
 - revoke their licence to provide ancillary services in categories where they have failed to deliver; and
 - in more extreme cases of ancillary service non-conformance, require the offending market participant to pay back all ancillary service revenue earned for that service since the last time it performed satisfactorily or over a period into the past of say 3 months (or a similarly chosen period).
- When a generator has been found to not conform to ancillary services, they can redeem themselves by undergoing SO testing and certification to demonstrate they can provide ancillary services to a satisfactory level or provide evidence that they have addressed the issue that prevented them from failing to deliver ancillary services in the past.
- Additional checks could also be made to ensure that the regulation requirement and total reserve levels are sufficient for managing frequency. This could be done based on checking whether statistical distributions of power system frequency lie within the preferred system normal range and checking to ensure that in aggregate, the amount of contingency reserves is sufficient to halt frequency deviations and restore frequency to the normal range.

The benefits of ACMS are:

- reduced manual intervention or human error;
- enhanced transparency – since participants will know the details of the algorithm(s) used to check for conformance; and
- consistency between the MO and SO in the implementation of ACMS.

4.9 Power System Performance Monitoring

The SO generally monitors power system operational performance across a range of areas to assess whether the power system is operated in a way that is compliant with the Grid Code. A shorter dispatch interval in combination with market-based ancillary services will allow the SO to use the market to manage issues presently being managed by the SO during real-time operations. However, the SO should actively monitor and assess:

- whether the amount of ancillary services being procured in the market is sufficient to maintain power system frequency within the limits specified in the Grid Code - it is



undesirable to procure too much of any given service as this will cost too much, nor too little as this will compromise power system security; and

- whether the security constraints included in the market clearing engine are sufficient to maintain the power system within a secure state – inappropriate or incorrectly formulated security constraints could compromise power system security or overly conservative security constraints could increase market costs.

This again is a subtle change in the role of the SO.

4.10 Grid Code and Market Rules Harmonisation

For a shorter dispatch interval, additional detail will need to be added or revisions made in the WESM Rules to cover the real time operations, scheduling, dispatch, management of power system security and the management of ancillary services. It is therefore suggested that harmonisation of the WESM Rules and Grid Code be done so that there can't be any confusion. An approach that would be the simplest would be to move the parts of the Grid Code concerned with operations, scheduling, dispatch, management of power system security into the WESM Rules. The WESM Rules would then be the single point of reference for management of these aspects of power system security for both the MO and SO.

4.11 Summary of Proposed System Operation Enhancements

Introducing a shorter dispatch interval has an impact on a number of aspects of system operations. We recommend the following to enhance the approach that is taken for system operations in the WESM, for a shorter dispatch interval:

- Replace the use of the MOT for making adjustments to generator outputs with schedules that are determined by the market clearing engine;
- Make going on AGC mandatory for market participants that are centrally dispatched and with capacity in excess of some threshold (say 30 MW) or alternatively allow the SO charge a management fee for non AGC generators;
- Bound post contingent network power flows by short-term thermal ratings of transmission lines (only for a dispatch interval of less than 15-minutes);
- Consider enhancing the frequency standards in the following way:
 - frequency standards specified in probabilistic terms rather than deterministic, for example “frequency within bounds 99% of the time”;
 - for system normal conditions, use a tighter frequency standard and maintain wider frequency bands for the alert, emergency states or islanding situations;
 - specify a requirement to return frequency back to within a normal range following some minimum period of time following a power system event (such as a contingency);
- Enhance the logic of the SO's AGC to automatically issue dispatch instructions for generators based on market dispatch outcomes for energy and market-based frequency regulation services;



- Enhance the management of MRUs to enhance transparency and to remove SO discretion;
- Enhance the Automatic Conformance Monitoring System (ACMS) so that it is better suited for conformance monitoring for a shorter dispatch interval, frequency regulation and to ensure providers of market-based ancillary services respond appropriately in response to power system events;
- Enhance the SO's power system performance monitoring to assess whether the market-based ancillary services regime is recruiting sufficient levels of reserves to manage power system frequency within the frequency standard; and
- Enhance the Grid Code and Market Rules to ensure that system operations and market operations are mutually consistent and harmonised.

These would largely need to be implemented as changes to the Market Rules, Grid Code, system operation procedures and market procedures.



5 Ancillary Services

5.1 Introduction

A shorter dispatch interval means:

- the energy market itself is able to perform the load following function that is presently being managed by the SO using the MOT and regulation reserves;
- within a dispatch interval there less capacity required for regulating frequency as compared to say a 30-minute or 1-hour period;
- some categories of reserve service, namely those that have long response times (such as 10-minute or 30-minute) can be sourced via the energy market; and
- there should be a reduced need for calling upon must-run plant to manage issues that arise within a 1-hour period (for example, fast-start units that take 10 to 15 minutes to start-up can be directly dispatched in the energy market - provided the gate closure is reduced).

Consequently, consideration of a shorter dispatch interval needs to also consider possible changes to the arrangements currently in place for market-based ancillary services. To this end, we need to review the proposed ancillary service arrangements with a view to identifying enhancements that would work in tandem with a shorter dispatch interval.

5.2 Proposed Ancillary Service Market Arrangements

On 8 January 2007 PEMC filed an application for ERC to approve the Pricing and Cost Recovery Mechanism for Reserves (PCRM). There have since been many refinements made to the original design.

The main features of the refined PCRM are³³:

- Reserve categories as set out in Table 6;
- Co-optimized dispatch of reserves and energy for plant but not co-optimized dispatch of reserve requirements;
- Zonal pricing for reserves (a single price for a reserve in a reserve region – intended to be Luzon, Visayas and Mindinao in the longer term);
- Ex-ante pricing of reserves;
- Cost recovery on a reserve cost recovery zone;
- Allocation of the costs for each service for each cost recovery zone to loads and generators based on a pre-determined factor (50:50 for generators and loads for regulation and all costs to generators for the other services); and
- Costs allocated on a MWh basis using the ex-ante dispatches and load forecasts;

³³ Based on (1) "Compliance to the Directives of Energy Regulatory Commission for the Pricing and Cost Recovery Mechanisms for Reserves in the Philippine Wholesale Electricity Spot Market", 16 February; (2) "Pricing and Cost Recovery Mechanism for Reserves in the Philippines WESM", Revised 16 February 2013; and (3) ERC Case No. 2007-004, "In the Matter of the Application for the Approval of the Pricing and Cost Recovery Mechanism for the Reserves in the Philippine Wholesale Electricity Spot Market", 2007.



- Inclusion of reserve effective factors (REFs) to be applied in settlements; and
- Limiting the schedule of a reserve provider to strictly one reserve category per interval.

In reference to the second of these items, a subset of ancillary service requirements are based on the largest single credible contingency that could occur. There are two main approaches that can be taken for setting the requirement for such services. The one advocated in the PCRM is to essentially determine the largest unit (based on SCADA measurements say) prior to the next dispatch interval and include a constraint in the dispatch engine that says the total amount of reserves capacity required must exceed this externally determined value. The problem with this is that it is suboptimal, for example, the reserve requirements could be reduced if the largest generator being dispatch was also reduced. The alternative is to let the dispatch engine itself optimise the requirements, so it would, for example, back off the largest generator if needed to minimise total dispatch costs for the dispatch interval.

To date, the ERC has not approved the PCRM; however, for the purpose of considering ancillary services in combination with a shorter dispatch interval, we based our comments on the PCRM and its subsequent refinements.

Table 6 Proposed market-based frequency control ancillary services³⁴

Reserve	Impact on net generation	Participating entities
Regulating Reserves	Raise / Lower combined	Generators
Fast Contingency Reserves	Raise	Generators and Loads
Slow Contingency Reserves	Raise	Generators and Loads
Dispatchable Reserves	Raise	Generators and Loads
Lower Reserves	Lower	Generators

5.3 Ancillary Services Categories

The Grid Code³⁵ (6.6.1) states that control of power system frequency will be managed by use of regulating reserves, contingency reserves and demand control. The PCRM proposes 5 categories of frequency control ancillary service (FCAS) for the WESM as set out in Table 6.

In Table 7 we set out the definitions of the FCAS and their nearest corresponding Grid Code definitions. The SO also uses the MOT to make adjustments to the dispatch instructions and uses MRUs for the provision of ancillary services.

³⁴ Note that at the time of writing, the categories in the PCRM were being revised.

³⁵ Reference: "Philippine Grid Code: Amendment No. 1", April 2, 2007, drafted by Grid Management Committee and approved by Energy Regulatory Commission.



Table 7 Proposed market-based frequency control ancillary services

Service	Market-Based frequency control ancillary service as defined in the Ancillary Service PCRM Application	Corresponding frequency control service definitions defined in the Grid Code
Regulation Reserves	Provides the ability to respond to small fluctuations in the system frequency including but not limited to those caused by load or generation changes (WESM Rules, Chapter 11). This is also termed as "Load Following and Frequency Regulation" (LFFR). Regulating reserves can be offered by approved generators that are certified by the SO and that are subject to the regulating headroom constraint (in addition to other reserve constraints).	(6.1.1.2) Frequency regulating (or load following) reserve shall include the following: (a) primary response & (b) secondary response of generating units. (6.6.2) defines primary response & secondary response: (6.6.2.1) primary response – generator operating in governor free mode (frequency sensitive mode), and must respond within a maximum response time of 5 seconds. (6.6.2.2) secondary response – generator dispatch instructions adjusted based on AGC or manual instruction from SO. Maximum response time is within 25 seconds and it must be sustained for at least 30 minutes.
Contingency Reserves (Fast and Slow)	<p>The ability to respond to a significant decrease in system frequency including but not limited to a decrease in system frequency in an interconnected AC network as a result of a credible contingency affecting one (or more) generation companies within that network, or transmission flows into that network (WESM Rules, Chapter 11). This is also termed as "Spinning Reserve". The distinction between "fast contingency" and "slow contingency" would be based on the rate of change of a provider's response to a frequency event.</p> <p>Also includes the ability of a customer to disconnect loads from the grid within a very short notice in response to a frequency deviation or a request from the system operator (WESM Rules, Chapter 11).</p>	<p>Corresponds to the first type of contingency reserve defined in (6.1.6.3) of the grid code: (a) spinning reserves (or hot standby reserves). (The other type defined in 6.1.6.3 is Dispatchable reserve – see below). (6.6.3) Spinning Reserve and Backup Reserve: (6.6.3.1) A generator providing spinning reserves as an ancillary service shall be synchronised with the grid and be available to automatically respond to any sudden loss or significant reduction in generating capacity.</p> <p>The Grid Code defines a range of demand side control and demand response measures in 6.6.1.4 (a) Automatic Load Dropping, (b) Manual Load Dropping, (c) Demand reduction on instruction by the System Operator, (d) Demand Disconnection initiated by users, (e) customer demand management, (f) voluntary load curtailment; some defined in greater detail in 6.6.4, 6.6.5, 6.6.7 and 6.6.8. A subset would be eligible to operate as contingency reserve services.</p>
Dispatchable Reserves	The ability to respond to a re-dispatch performed by the System Operator during a trading interval, on either a regulator or on an ad hoc basis (WESM Rules, Chapter 11). This is also called: "back-up reserve".	Corresponds to the second type of contingency reserve defined in (6.1.6.3) of the grid code: (b) backup reserves (or cold standby reserves). (The first type is the Contingency Reserve service defined above). (6.6.3) Spinning Reserve and Backup Reserve: (6.6.3.2) A generator providing spinning reserves as an ancillary service shall be synchronised with the grid and be available to automatically respond to any sudden loss or significant reduction in generating capacity. A generating unit that provides backup reserve must



Service	Market-Based frequency control ancillary service as defined in the Ancillary Service PCRM Application	Corresponding frequency control service definitions defined in the Grid Code
		<p>have fast start capability (i.e. synchronised to grid within 15 minutes & able to operate at dispatched MW level) and its capacity needs to be sustainable for at least 8 hours.</p> <p>The Grid Code also defines a range of demand side control and demand response measures in 6.6.1.4 (a) Automatic Load Dropping, (b) Manual Load Dropping, (c) Demand reduction on instruction by the System Operator, (d) Demand Disconnection initiated by users, (e) customer demand management, (f) voluntary load curtailment; some defined in greater detail in 6.6.4, 6.6.5, 6.6.7 and 6.6.8. A subset would be eligible to operate as dispatchable reserves.</p>
Lower Reserves	A category wherein qualified providers would be called to lower their generation output in the case of a sudden net reduction in load. The PCRM states that this is intended to limit the occurrence of “over-frequency” events.	Not explicitly defined in the Grid Code.

A shorter dispatch interval requires the definitions of the services to be revisited based on the nature of their responses. For example, for a 5-minute dispatch interval, slow acting reserves with response times exceeding 5-minutes can be dispatched directly in the 5-minute market for energy. It was noted in the Phase 1 report that the proposed frequency control ancillary service definitions do not adequately span the full range of frequency services that that may be required in the Philippines³⁶. If the ancillary service definitions are reworked to be appropriate for a shorter dispatch interval then it also makes sense at the same time to harmonise their definitions across the Grid Code and Market Rules. As evidenced in Table 7, there are differences between the definitions in the current version of the Grid Code and the services that have been defined in the PCRM that need reconciliation.

Traditionally, ancillary service categories are defined by the SO based on the underlying capability of specific technologies that are connected to the grid; for example, the response times of primary and secondary reserve services or frequency sensitive load-shedding schemes. For the purpose of market design rather than define the categories of ancillary service based on the existing set of technologies that are in place to provide ancillary services, it is generally better to introduce a set of categories for the ancillary services that are defined in a technologically neutral manner (based on generic responses) and that support the participation of any facility (whether it is a generator or load) that is capable of providing the responses consistent with the technology-neutral definition. An example of a set of frequency control ancillary services that would be

³⁶ The topology and nature of transmission network of the Philippines grid means that to properly manage power system frequency; the location of reserves can't be ignored.

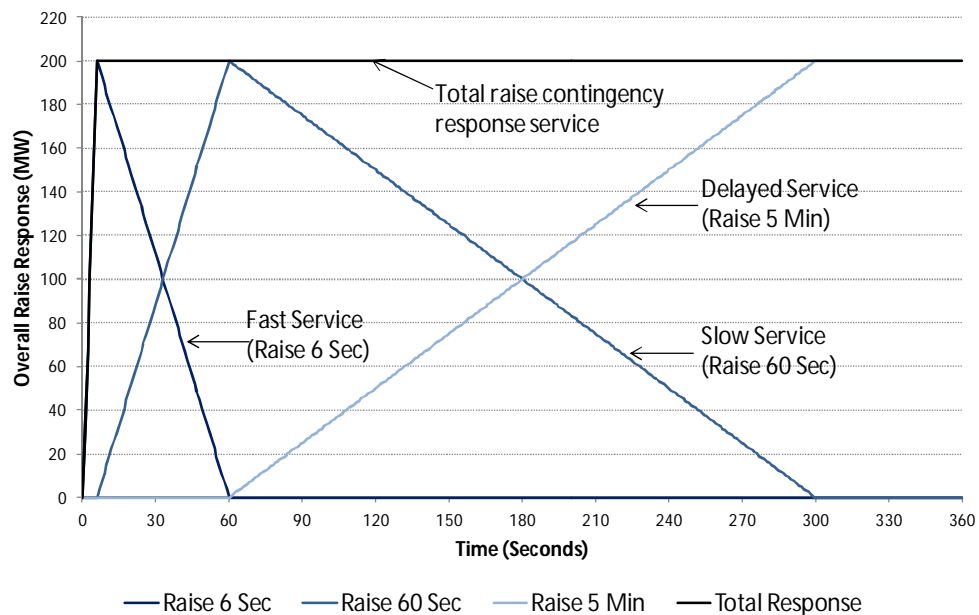


suitable for a 5-minute dispatch interval is given in Table 8. Following a generator outage, for example, the corresponding response of the 3 contingency raise services would be as shown in Figure 19. Here it can be seen that the individual services respond with different response times and are sustained for the required levels. In this example, the aggregate response from all contingency reserve providers would provide an extra 200 MW of generation from 6s onwards and would replace the lost generation arising from the contingency.

Table 8 Example frequency control ancillary services for a 5-minute dispatch interval

Reserve Service	Impact on frequency	Time to start delivery of reserve	Time to full delivery of reserve	Time reserve needs to be sustained
Fast Contingency Raise Reserve	Raise	0 s	6 s	60 s
Fast Contingency Lower Reserve	Lower	0 s	6 s	60 s
Medium Contingency Raise Reserve	Raise	6 s	60 s	5 min
Medium Contingency Lower Reserve	Lower	6 s	60 s	5 min
Slow Contingency Raise Reserve	Raise	60 s	5 min	10 min
Slow Contingency Lower Reserve	Lower	60 s	5 min	10 min
AGC Raise Regulation	Raise	2-9s	2-8s	5 min
AGC Lower Regulation	Lower	2-9s	2-8s	5 min

Figure 19 Example of ancillary service contingency raise responses



5.4 Co-optimisation of Energy and Ancillary Services

The trade-off between the provision of energy and ancillary services is reasonably complex and changes from one dispatch period to the next.

The energy and the ancillary service markets are presently cleared sequentially. Ancillary service providers first submit their nominations to the SO who determines how many MWs of each type of reserve need to be scheduled for each generator for the following day. Once this is done the generators are able to offer their remaining capacity to the WESM's energy market.

The sequential approach can only be suboptimal as it will not be able to find the best trade off in the provision of energy and ancillary services on a dispatch period by dispatch period basis. Co-optimisation of energy ancillary services allows for the simultaneous joint optimisation of energy and reserves, which – if properly implemented – ensures that just the amount of reserves needed are recruited at least cost.

The proposed WESM reserve market intends to have:

- co-optimized dispatch of reserves and energy for plant but not co-optimized dispatch of reserve requirements;
- zonal pricing for reserves: a single price for a reserve in a reserve region (Luzon, Visayas and in the longer term, Mindanao); and
- ex-ante pricing of reserves.

The following are market design options that can be evaluated as part of an MMS upgrade and as part of implementing a shorter dispatch interval:

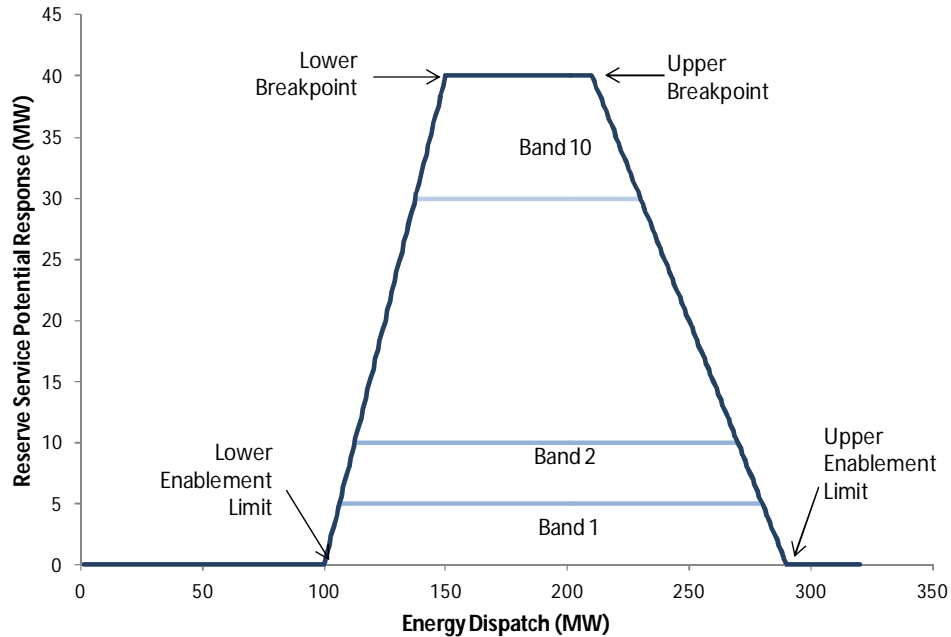
- reserve categories as discussed in section 5.2;
- whether to have reserve requirements as fixed inputs or whether to let the market dispatch optimisation (MDOM or a new optimisation system) optimise them for the subset services where this is possible;
- introducing joint capacity constraints to ensure that the combination of energy and reserve dispatches are physically feasible in terms of a generator's (or load's) maximum and minimum loading capabilities; and
- introducing joint ramping limits for ancillary services and energy to ensure that the combination of energy and reserve dispatches are physically feasible in that the energy dispatch and the enabled reserves could be physically delivered should the system require them.

Co-optimisation should lead to reduced ancillary service costs and it means that the capacity of plant that is essentially dedicated to the provision of ancillary services (such as the Kalayaan pumped storage units) can be used optimally between energy and ancillary services. We also understand that being able to source ancillary services from different locations on the network would – at times – alleviate congestion around the metro Manila part of the network.

An important part of co-optimisation is ensuring that market participants are able to provide offers that express their own trade-offs between the provision of energy and ancillary services both in terms of capacity and in terms of ramping capability for all the services that they are able to provide. This can be done via careful formulation of plant capacity and ramping constraints for the joint dispatch of energy and reserves. An alternative, though largely equivalent approach, which has been adopted in Australia is to describe the joint capability of providing energy and a particular ancillary service using

the so-called "trapezium constraints". An example of such a trade-off between energy and one ancillary service using a trapezium is illustrated in Figure 20.

Figure 20 Energy and ancillary service trade-off for a generator



Given an appropriate way of describing or representing the joint tradeoffs between energy and ancillary services, the optimisation can then select the optimal combination of energy and ancillary services for each generator such that the ancillary service requirements (see section 5.5) are satisfied. So long as the reserve categories define mutually distinct and technology-neutral ancillary service responses, the proposed refinement to the PCRM to limit "the schedule of a reserve provider to strictly one reserve category per interval", is not a good idea.

In general a generator (or load) is able to provide multiple ancillary services because they can respond on different time frames and in different directions to a frequency event. For example, a generator could provide fast-acting contingency reserves (raise and lower) and/or be able to regulate frequency (both raise and lower). To impose such a restriction limits the efficiency of the reserve market and co-optimisation. This restriction would (1) forego the benefits of a generator or load that is able to provide ancillary service responses across more than 1 category of service, (2) introduce unnecessary complexity into the optimisation algorithm as a large number of binary variables would most likely need to be introduced to ensure that each ancillary service provider only provides at most 1 service at 1 time, and (3) would increase ancillary service prices and reduce competition for at least some categories of ancillary service.

An important part of introducing an ancillary services market is to maximise the competition to provide services, therefore allowing participants to make offers into

energy and all the ancillary service markets they are able to provide, including a technical specification of the trade-offs between them is critical to the success of the market.

Note, however, due to the nature of the technical capability of many units, if the trapezium approach is used it is possible for generators to become “trapped” (inside the trapezium) or stranded (outside the trapezium). The equivalent can occur with other formulation approaches. The options for overcoming this are:

- use binary variables to eliminate the problem (although it can lead to an increase in the solve time); or
- simply require participants to adjust their generation offers accordingly, across energy and the ancillary services, but this would require a short gate closure so that participants can “trade” their way out of being trapped or stranded in a timely manner.

It is understood that part of the reason for restricting generators to providing at most 1 ancillary service was to allow the SO to readily compute REFs – in particular, if a generator can only ever be enabled to provide one ancillary service then there is less ambiguity in assessing its performance to provide the one type of ancillary service it is meant to provide. We later argue that REFs aren’t needed (see section 5.6) and so this difficulty is avoided. Nevertheless, the SO should still monitor the provision of ancillary services when they are needed (as described in section 4.8).

So long as ancillary service categories are defined in a way that corresponds to mutually distinct and technologically neutral responses as per section 5.3, it would not be difficult to assess the performance of a generator that is enabled to provide multiple ancillary services simultaneously. Furthermore, any generator that is required to simultaneously provide multiple ancillary services would be required to provide an aggregate / overall response to a contingency, so the SO should be assessing whether or not they provided this overall response.

5.5 Ancillary Service Requirements

The present practice used for requirement setting for the 3 main types of frequency control service in the WESM are summarised in Table 9. On average the System Operator schedules 490 MW of frequency control ancillary services each hour: around 200 MW for regulation reserves (REG), 200 MW for contingency reserves (CON) and 90 MW for dispatchable reserves (DIS). Note that the maximum amount of the different reserve types are: 398 MW (CON), 272 (DIS) and 311 (REG).

Table 9 Frequency control ancillary service requirement setting

Category of service	How the requirement is presently set ³⁷
Regulating Reserve (REG)	Set equal to the average load forecast variance. At the present time, the SO has determined the amount of regulation required to be 4% of the day-ahead load projection.

³⁷ Based on the practice that applies to Luzon.



Contingency Reserve (CON) / Spinning Reserve	It is assessed by the SO on a day-ahead basis for each hour and set equal to the expected loading level of the most heavily loaded generation unit that is expected to be online.
Dispatchable Reserve (DIS) / Backup Reserve	It is assessed by the SO on a day-ahead basis for each hour and set equal to the expected loading level of the second most heavily loaded generation unit that is expected to be online.

The introduction of market-based ancillary services means that the MO-SO interface will need to be enhanced to enable the SO to specify the requirements for each service. The ancillary service requirements should be directly linked to the grid standards and the SO will need to refine their procedures so that they:

- develop methodologies that are compatible with the market interface for specifying ancillary service requirements;
- develop procedures to compute each of the requirements appropriately based on the system frequency standard, or alternatively, for contingency services have the requirements computed as part of the co-optimisation of energy and ancillary services;
- monitor the performance of the power system to ensure that the standards are adhered to; and
- if necessary rework the computation of requirements if there is evidence the computed requirements are inadequate to maintain the power system within the relevant standards.

For a 5-minute dispatch interval (assuming the ancillary services are defined as shown in Table 7), a suitable approach for setting the requirements in each ancillary service region is set out in Table 10.

Note that if the requirements are optimised, then the SO will not need to provide the MO with much information at all, as MDOM will be essentially working out the minimum cost requirements for the services that have optimised requirements. In this case, the SO will just need to:

- monitor whether sufficient reserves are being recruited, when they are called on and whether they were provided; and
- periodically reviewing the load relief parameter, as it could be expected to change over time.

Table 10 Example of setting the frequency control ancillary service requirements based on Australian NEM

Reserve service	Impact on frequency	What drives the requirement	Approach for setting the requirement
Fast Contingency Raise Reserve	Arrest frequency dropping within 6s of contingency	Single largest loss of a net power injection in the system, such as: output of largest generator, power imports or certain types of single network contingencies.	$\text{Max}(\text{NI}[i]) - \text{LRF}_a \times D$, where:



Reserve service	Impact on frequency	What drives the requirement	Approach for setting the requirement
			NI[i] are all (scheduled) net power injections in the region, LRF is the load relief factor ³⁸ and D demand.
Fast Contingency Lower Reserve	Arrest frequency rising within 6s of contingency	Single largest loss of a net power off-take in the system, such as: major load trips, power exports or certain types of single network contingencies.	$\text{Max}(\text{NO}[i]) - \text{LRF}_a$, where: NO[i] are all (scheduled) net power off-takes in the region; LRF is the load relief factor and D demand.
Medium Contingency Raise Reserve	Raise frequency so it is within system normal standards 60s after contingency	Single largest loss of a net power injection.	$\text{Max}(\text{NI}[i]) - \text{LRF}_b \times D$
Medium Contingency Lower Reserve	Lower frequency so it is within system normal standards 60s after contingency	Single largest increase in net power.	$\text{Max}(\text{NO}[i]) - \text{LRF}_b \times D$
Slow Contingency Raise Reserve	Raise frequency until it is at the frequency standard (e.g. 60Hz)	Single largest loss of a net power injection.	$\text{Max}(\text{NI}[i])$ Note that LRF is not included here b/c a 1 for 1 replacement of MWs is required.
Slow Contingency Lower Reserve	Lower frequency until it is at the frequency standard (e.g. 60Hz)	Single largest increase in net power.	$\text{Max}(\text{NO}[i])$ Note that LRF is not included here because a 1 for 1 replacement of MWs is required.
AGC Raise Regulation	Raise frequency	Small variations in frequency driven by supply and demand never perfectly matching	Set to the MWs required to maintain frequency within the normal band with high probability. An approach that could be adopted is set out in section 6.
AGC Lower Regulation	Lower frequency		

5.6 Reserve Effectiveness Factors

A general issue with any ancillary service market is that payments are made for services that are not needed most of the time because contingencies occur infrequently. This leads to the problem of ensuring there are incentives in place to ensure that when a contingency does occur, the equipment of participants actually provides the response that has been procured.

The PCRM proposes to use reserve effectiveness factors (REFs), which would be computed based on the past responses of participants' equipment to contingencies. The factors would take values between 0.8 and 1.0, where 1.0 means that a generator is 100% effective. The REFs will be used to scale down the estimated supply of reserve ancillary services from a unit. The idea of REFs is to compensate for expected non-performance by some generators. The approach appears to have been influenced by the approach used in the National Electricity Market of Singapore (NEMS). It effectively introduces discriminatory pricing for products that (at least within an ancillary service region that is not subject to islanding conditions) have uniform prices since the contribution to

³⁸ The load relief factor (LRF) is the corresponding % (or fraction) change in demand owing to the passive response of induction motors, governor responses and the responses of other frequency-sensitive equipment connected to the power system. The change in demand is always in a direction that tends to alleviate the deviation in frequency, for example, if there is a reduction in frequency, the load relief is negative.



correcting a frequency deviation is the same irrespective of the location within a power system that it is provided.

There are two main problems with the use of REFs:

- Firstly, for the fast contingency services, the reserves need to have an automatic response to substantial changes in system frequency. If a number of reserve providers are enabled / scheduled to provide the fast contingency services and these providers are deemed to have REFs which are around 0.8, say, then if these reserve services delivered fully then too much reserve might be used and system frequency could overshoot which in turn could cause problems. It will also raise costs as greater quantities of ancillary services will need to be enabled.
- Secondly, if REFs are computed annually³⁹ (or longer) then a participant that has an undesirable REF faces a diminished incentive to provide ancillary services and consequently the competition to provide reserves is reduced and prices are likely to go up. Furthermore, if there are shortages of ancillary service providers, then system security will also be at risk.

The following is an appropriate way of addressing the issue that we understand motivated the introduction of REFs to the PCRM:

- Ensure that the technical capability of generators to provide ancillary services can be properly reflected in the market clearing engine. This will ensure that no ancillary service provider is only ever required by the market to provide a combination of energy and ancillary services that they are able to physically deliver (this is discussed further in section 5.4);
- Introduce a testing and certification regime (managed by the SO) to audit / register / check the response capabilities of each unit potentially providing an ancillary service (and at the same time confirm / check / calibrate the technical energy and ancillary service technical trade-offs – discussed in section 5.4). This basically minimises the risk of a market participant offering into an ancillary services market ancillary service offers that they are unable to fulfil; and
- Enhance the dispatch compliance and conformance monitoring regime to include monitoring of responses of enabled generators to frequency events (as discussed in section 4.8). This could even involve financial penalties for generators which failed to perform when a contingency occurred.

In the case of Australia and New Zealand, these measures have proven to provide sufficient incentives on participants to ensure that their equipment provides the right ancillary service responses when there has been a frequency event. A way of strengthening the incentive would be to require any ancillary service providers found to not provide any response to be fined an amount equal to the revenue they previously earned for ancillary services for a period sufficiently far into the past (say 3 months).

³⁹ Note that they can't be computed any more frequently than there are contingencies / frequency events.



5.7 Ancillary Service Contracts

The same observation from the Phase 1 report applies here, and is repeated for completeness. Our understanding is that the SO is currently negotiating reserve contracts. These contracts should either have termination clauses in them that state that the contract ceases when the co-optimised reserve spot market starts or there should be provisions that these contracts to be converted to contracts for differences (CfDs) referenced against the relevant reserve spot prices. If neither of these options is acceptable, there might be other suitable arrangements to transfer from contracts with the SO to a co-optimised market but these should be set up before there is too much capacity tied up in contracts which extend beyond the beginning of the reserve spot market.

5.8 Summary of Proposed Ancillary Services Enhancements

The following proposals are suggested to enhance the arrangements for market-based ancillary services in the WESM (as defined in the PCRM), to support a shorter dispatch interval⁴⁰:

- Refine the ancillary service categories so that they are a better match for a shorter dispatch interval and so that they correspond to technology-neutral responses that are mutually distinct. Note that ancillary services that have slow response times or that are concerned with load following can instead be dispatched as energy services for a shorter dispatch interval, so those categories can be removed.
- Harmonise the market-based ancillary service definitions with the definitions of the frequency control ancillary services in the Grid Code;
- Introduce market-based ancillary services with the following features:
 - co-optimisation of energy and ancillary services;
 - optimisation of ancillary service requirements for the subset of services where this is possible;
 - zonal pricing;
 - introduce joint capacity constraints to ensure that the combination of energy and reserve dispatches are physically feasible in terms of a generators (or loads) maximum and minimum loading capabilities; and
 - introduce joint ramping limits for ancillary services and energy to ensure that the combination of energy and reserve dispatches are physically feasible;
- Remove the requirement in the PCRM to “limit the schedule of a reserve provider to strictly one reserve category per interval”. Generators or loads that are able to provide multiple reserves simultaneously should have the capability to do so represented in the dispatch and pricing model formulation. To impose the restriction of allowing a unit to be dispatched for one reserve per dispatch interval would limit the efficiency of the reserve market and co-optimisation. It also foregoes the benefits of having generators or loads that are capable of providing multiple ancillary

⁴⁰ Note that most of the recommendations we set out here would apply irrespective of the dispatch interval duration, but having a dispatch interval of 5-minutes to 15-minutes would requires.



service responses across more than 1 category of service. Furthermore, this would introduce unnecessary complexity into the optimisation algorithm as a large number of binary variables would be required.

- The SO will need to introduce processes to monitor whether sufficient levels of reserves are being recruited and whether the generators that are required to provide ancillary services (in each dispatch interval) provide them when there is a frequency event;
- Remove REFs as they can introduce unusual (and undesirable) incentives. It is better to focus on issues like developing procedures for assessing whether the ancillary service providers actually were able to provide the services when / if called upon to do so (an SO role) and ensuring that the joint capacity and joint ramping limits are represented properly in the market clearing engine, so that there will be a reasonable match between the market clearing engine's representation of generators and the actual capability of the generators in providing ancillary service responses; and
- Introduce expiration provisions in the ancillary service contracts that are to be renewed in the short-term, so that eventually all ancillary services that are market-based are managed via the market, as opposed to "out-of-market" commercial contracts.



6 Analysis of Regulation Requirement

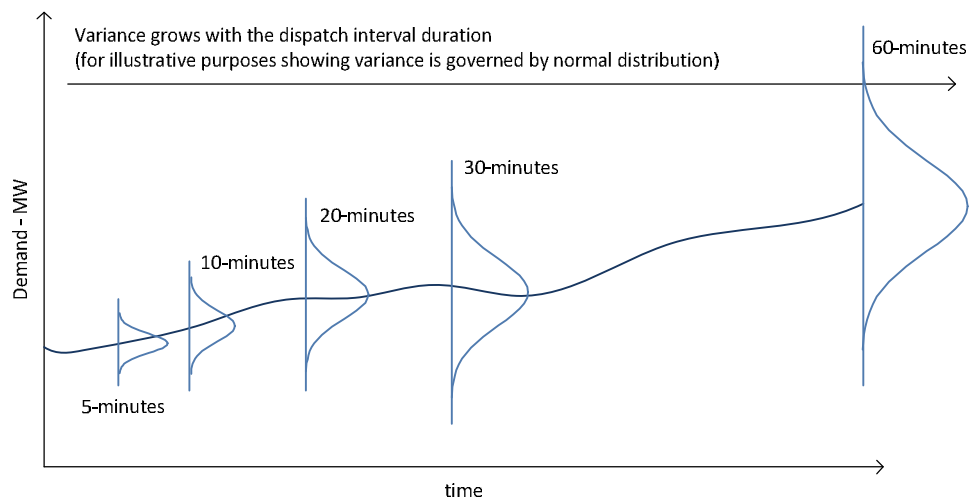
6.1 Introduction

The amount of regulation that is required depends on a number of factors including load forecast errors, deviations of generators that are not providing regulation from their scheduled quantities, transmission line losses and the amount of generation required to return the system frequency to nominal⁴¹. This section provides an analysis of demand data in order to provide a basic assessment of how the regulation required can be expected to change as a function of dispatch interval duration.

6.2 Approach

The amount of regulation can be based on the standard deviation of the sum of all sources of deviations in supply and demand in an electrically connected alternating current network and ideally directly linked to a probabilistic frequency standard. For increasing dispatch interval durations, the variance associated with the deviations can generally be expected to increase. The amount of regulation required to correct the sources of deviation in supply and demand therefore also increases. We illustrate the concept in Figure 21, where for simplicity we have used demand as a proxy for the deviations and show the increasing variance with normal distributions, although we should note that in practice the deviations may be governed by a different probability distribution, though we have found that for the Australian market, the normal distribution is quite a good approximation.

Figure 21 Conceptual illustration of increasing variance in demand for different dispatch interval durations



To analyse how the variance and standard deviation change as a function of the dispatch interval duration, we did the following.

⁴¹ 60 Hz in the Philippines.

1. Collected 1-minute SCADA snapshots of the demand in Luzon and Visayas for a 1 year period (11 April 2012 to 10 April 2013).
2. Made adjustments to the data to fill in a number of gaps with reasonable values based on neighbouring data⁴².
3. Analysed the variance of the difference between the demand at time t and at time $t-s$ for Luzon Visayas separately for time lags of s ranging from 0 to 120 minutes. That is we estimated:

$$V(s) = E[\{ X(t) - X(t-s) \}^2]$$

The function $V(s)$ is just two times the semivariogram, which is a function that is sometimes used to analyse stochastic processes. It is similar to the auto-covariance or auto-correlation functions but has the property of tending towards zero as s tends to 0, whereas the auto-correlation function tends to 1 as s tends to 0. It could be thought of as a rough measure of the load forecast error if you used the value $X(t-s)$ to forecast $X(t)$. For our purposes, the regulation requirement is related to $V(s)^{1/2}$, which is a measure of the standard deviation of a load forecast error for a period s into the future.

While it is recognised that frequency deviations in Luzon can be corrected from Visayas and vice versa, since they are separated by a HVDC link which is classified as a single contingency, it makes sense to consider regulation requirements in each region separately⁴³. To calculate a system-wide regulation requirement, the variances of Visayas and Luzon need to be added together and their square root taken. When this is done, the system-wide regulation requirement will be dominated by Luzon, which is much larger and consequently will have a much larger variance.

6.3 Results for Luzon

Figure 22 and Figure 23 show the variance for respectively lags from 0 to 120 minutes and from 0 to 60 minutes. The former illustrates that for lags of 0 to 60 minutes there is an exponential increase in variance, which tends towards being linear for lags greater than 60 minutes.

⁴² Note that there were not many gaps in the data provided.

⁴³ In fact, it would probably make sense to consider the regulation requirements for each of the islands in Visayas as many of the transmission links between the islands are single credible contingencies.



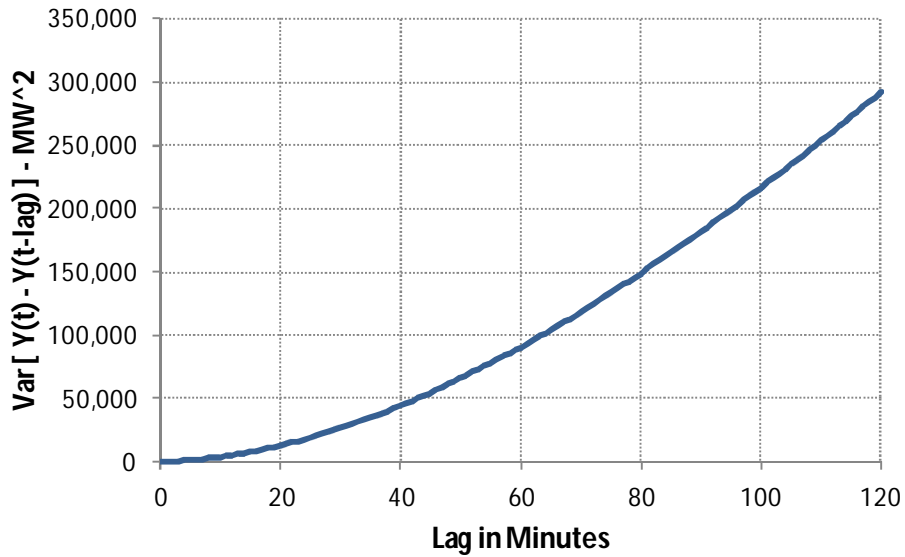
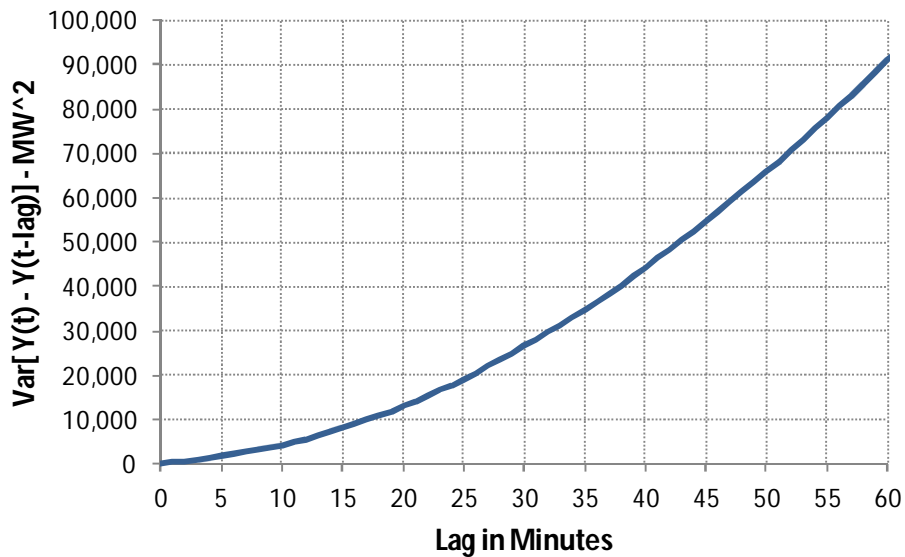
Figure 22 Variance in Luzon demand for lags from 0 to 120 minutes**Figure 23** Variance in Luzon demand for lags from 0 to 60 minutes

Figure 24 shows the standard deviation for lags from 0 to 60 minutes. This chart can be interpreted as being the amount of regulation that would be required to correct 68% of the intra-hour variations in demand for dispatch interval durations from 0 to 60 minutes. If a tighter standard was required, then it could be based on multiples of the standard deviation. For example, if the regulation requirement needed to be set so that it would be able to correct 95% of the intra-hour variations, then two standard deviations would be needed.



Figure 24 Standard deviation of Luzon demand for lags in minutes from 0 to 60 minutes

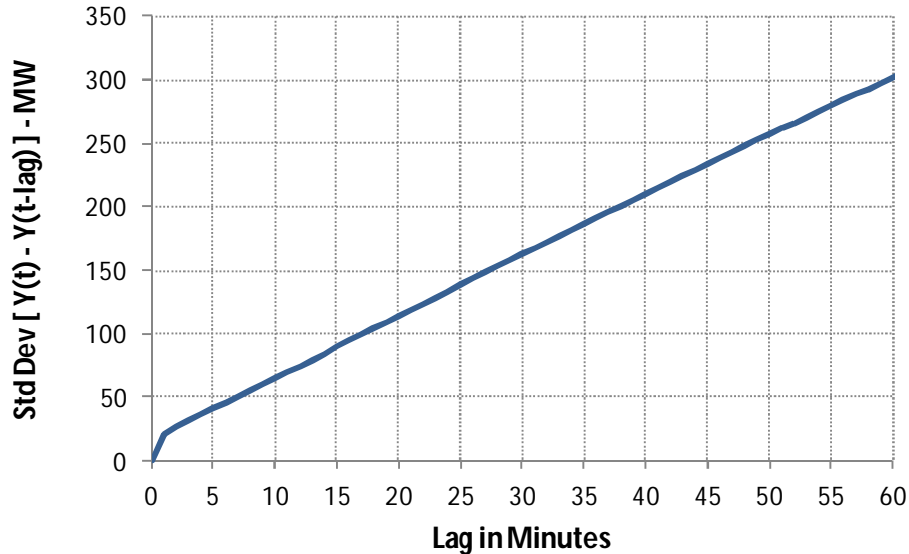


Figure 24 shows that:

- There is a significant reduction in the amount of regulation that is needed between a 60 minute dispatch interval compared to a 5-minute dispatch interval:
 - based on 1-standard deviation (68% of the time), 300 MW for a 1-hour dispatch interval vs. 42 MW for a 5-minute dispatch interval; or
 - based on 2-standard deviations (95% of the time), 600 MW vs. 82 MW.
- We observe that the amount of frequency regulation for a 1-hour lag is 300 MW, which is remarkably close to the amount of regulation that is presently being used in the WESM. As discussed in section 5.5, on average 200 MW is set aside for frequency regulation and 90 MW for dispatchable reserves, which is an ancillary service that provides a similar capability to frequency regulation⁴⁴.

6.4 Results for Visayas

For Visayas, we present similar results as for Luzon in Figure 25, Figure 26 and Figure 27. In a similar way to Luzon, there is a significant reduction in the amount of regulation that is needed for a 60 minute dispatch interval compared to a 5-minute dispatch interval:

- based on a 68% / 1-standard deviation standard, 70 MW for a 1-hour dispatch interval vs. 9 MW for a 5-minute dispatch interval; or
- based on a 95% / 2-standard deviation standard, 140 MW vs. 18 MW.

⁴⁴ Note that it is not clear how many MWs the SO uses for correction of intra-hour variations using the MOT.



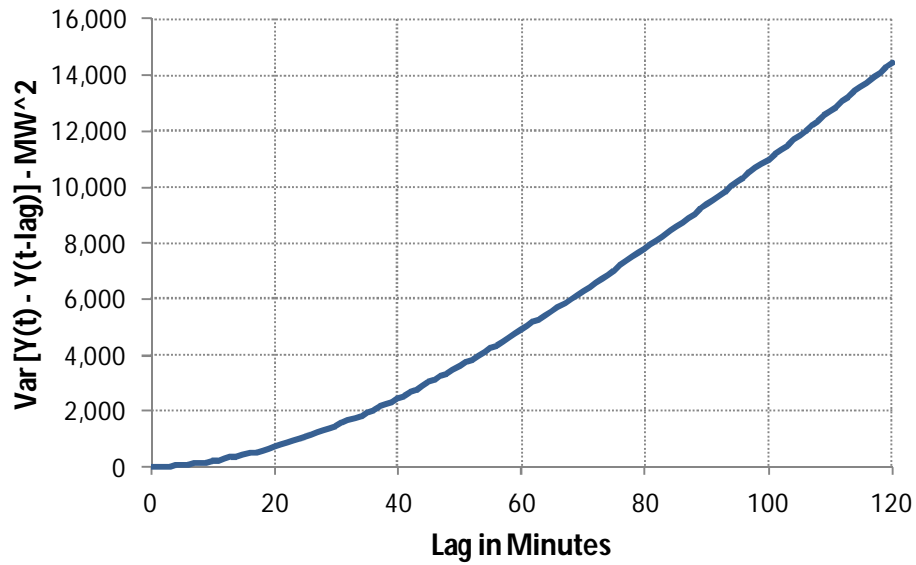
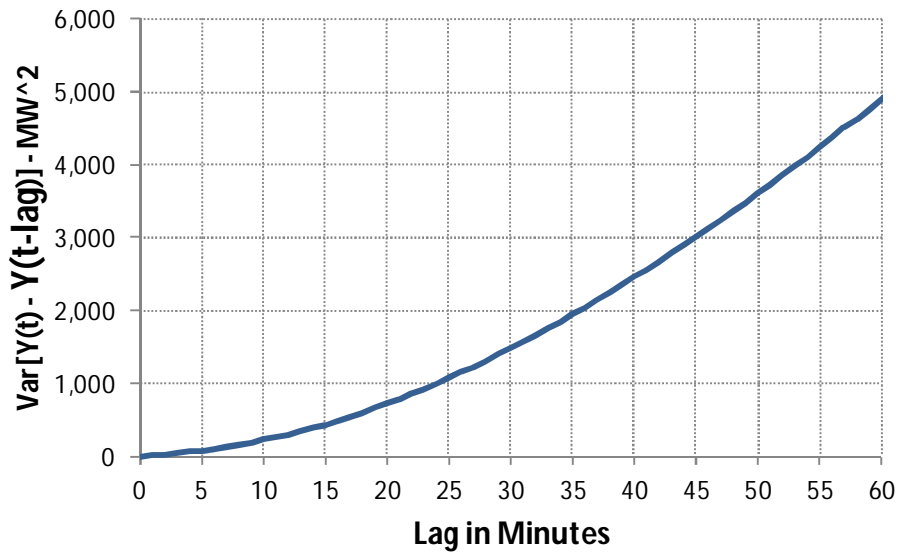
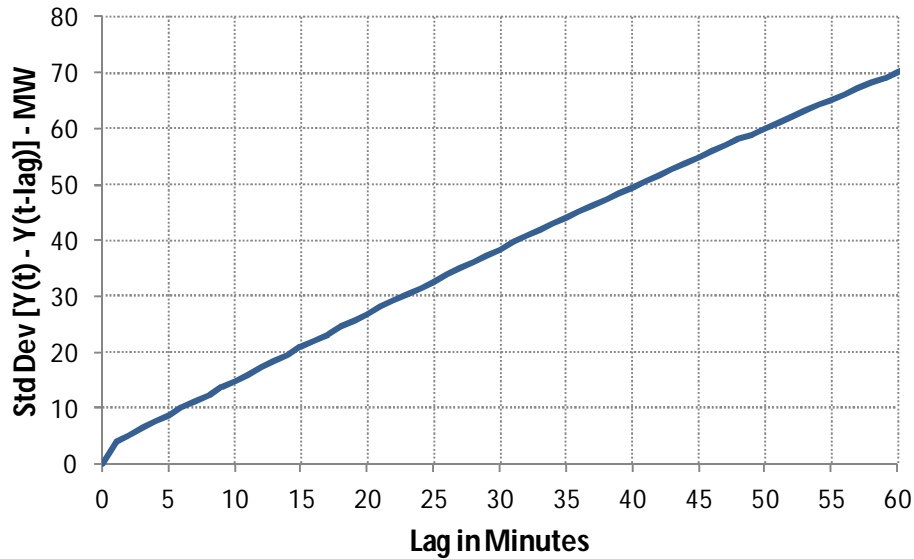
Figure 25 Variance in Visayas demand for lags from 0 to 120 minutes**Figure 26** Variance in Visayas demand for lags from 0 to 60 minutes

Figure 27 Standard deviation of Visayas demand for lags in minutes from 0 to 60 minutes



6.5 Implied Regulation Requirements for Different Dispatch Intervals

Table 11 summarises the findings for Luzon and Visayas assuming two different standards. We conclude from this table, that if we were to take the more conservative of the standards (2 standard deviations) then for a 5-minute dispatch interval, around 86 MW of frequency regulation would be needed for Luzon and Visayas combined, and for a 10-minute dispatch interval around 133 MW. This compares to the 290 MW⁴⁵ that is presently nominated on average (excluding any re-dispatch that the SO does intra-hour using the MOT).

We can therefore conservatively claim that a 5-minute dispatch interval would result in a saving of around 204 MW of capacity that would otherwise be reserved for performing frequency regulation. Similarly, a 10-minute dispatch interval would result in a saving of around 157 MW.

⁴⁵ Note that this includes the 90 MW of dispatchable reserves.



Table 11 Implied regulation requirements for different dispatch interval durations and standards

Dispatch Interval (mins)	Implied regulation requirement for Luzon (MW)		Implied regulation requirement for Visayas (MW)		Total regulation requirement for Luzon + Visayas (MW)	
	$1\sigma^{46}$	$2\sigma^{47}$	1σ	2σ	1σ	2σ
5	42.0	83.9	8.8	17.6	42.9	85.7
10	65.0	129.9	14.8	29.7	66.6	133.3
15	89.6	179.1	20.9	41.7	92.0	183.9
20	114.0	228.0	26.8	53.7	117.1	234.3
25	138.5	276.9	32.7	65.4	142.3	284.5
30	162.7	325.4	38.5	76.9	167.2	334.3
35	186.7	373.4	44.1	88.1	191.8	383.6
40	210.5	420.9	49.5	99.1	216.2	432.4
45	233.8	467.7	54.9	109.7	240.2	480.4
50	256.9	513.7	60.0	120.1	263.8	527.6
55	279.4	558.8	65.1	130.2	286.9	573.8
60	301.5	603.0	70.0	140.0	309.5	619.1

6.6 Expanding the Approach

A more sophisticated approach can be developed to compute the regulation requirement. It should be possible to determine the amount of regulation that is required explicitly from measurements on the sources that drive the need for the regulation service. These are:

- load forecast error (a random variable DL);
- load variability within the dispatch interval about the forecast trajectory (a random variable L);
- variability of non scheduled generator outputs such as wind (a random variable DN);
- deviations of scheduled generators from their dispatch targets (a random variable DG); and
- deviations of frequency from 60 Hz (a random variable FA).

At time t, the amount of regulation that would need to be used to return the system to 60 Hz (the real time requirement for regulation) is:

$$RR(t) = DL(t) + L(t) + DN(t) + DG(t) + FA(t)$$

The frequency standards require that when the system is operating in a normal state, for frequency to be between 59.7 Hz – 60.3 Hz. As noted earlier, the frequency standards in the Grid Code are specified on a deterministic basis, but for practical purposes if we assume that the frequency must remain within this band for say 95% (corresponding to

⁴⁶ Assuming 1 standard deviation as the basis for regulation requirement

⁴⁷ Assuming 2 standard deviations as the basis for the regulation requirement



two standard deviations) of time that has not been affected by a generation, load, network or multiple contingency event.

The size of the regulation requirement (the minimum amount of regulation that should be enabled) at any one time t can therefore be computed as the smallest $r(t)$ that satisfies:

$$P\{ -[r(t) + \text{LRF} \times D(t)] < \text{RR}(t) < [r(t) + \text{LRF} \times D(t)] \} > 0.95$$

The load relief factor, LRF, is used to adjust the actual system demand, $D(t)$, to adjust the regulation requirement to avoid unnecessarily recruiting too much. The probability distribution of $\text{RR}(t)$ can be readily computed based on statistical analysis of equation given above, using an approach not all that different to the one we set out in section 6.2.

6.7 Conclusions from Analysis of Regulation Requirement

The main conclusions to draw from the analysis that we have presented in this section is that under a shorter dispatch interval, the regulation requirement will be reduced, in particular:

- A 5-minute dispatch interval would on average result in an 204 MW reduction in the regulation requirement (compared to present);
- A 10-minute dispatch interval would on average result in a 157 MW reduction in the regulation requirement (compared to present);

The methodology that we have presented in this section could be enhanced and/or adopted by the SO as a more direct statistical and quantifiably justifiable approach in determining regulation requirements in Luzon, Visayas and the WESM generally.



7 Market Participant Operations

7.1 Introduction

We earlier made the observation that for a decentralised electricity market, generators⁴⁸ make more decisions on their own as compared to a centralised electricity market. The means that the “feedback loop” between the generators and the electricity market’s central dispatch and pricing process needs to provide timely updates on market and system conditions. So long as the generators are able to respond to changing market conditions, by making adjustments to their offers, the market will be enhanced and will benefit from increased flexibility.

However, apart from enhancing market and system operations, a key component in the feedback loop is ensuring that generators will be able to operate effectively in an electricity market that has energy, ancillary services, effectively no gate closure and a concept of dispatch interval operations and trading interval settlements. Apart from IT system changes (which we discuss later in section 9), this section briefly reviews the following areas of generator operations:

- spot trading in energy and ancillary service markets;
- management of dispatch targets and ancillary service enablement⁴⁹ levels; and
- managing bilateral contracts.

7.2 Spot Trading Operations

Under a shorter dispatch interval with co-optimised energy and ancillary service markets, generator traders will need to:

- manage their energy market operations, as they presently do, but observe that they will need to monitor market outcomes more frequently than hourly; and
- manage their offers for not only energy but numerous ancillary services, where there will be interactions between all services offered and there will be an increased need to ensure that the technical capability of their equipment is adequately reflected in their offers.

Having a shorter dispatch interval and introducing an ancillary service market will add complexity to energy trading. During Phase 1, we developed a simple survey which posed a range of generation scenarios for which the traders had to construct offers. Our survey was focused solely on spot trading for energy. Based on this survey, we noticed that a number of the traders were bidding in suboptimal ways. As a result we felt that there was a general lack of training and knowledge in this area, which ultimately affects market efficiency.

⁴⁸ Note that by “generators” we generally refer to all market participants.

⁴⁹ We use the term “enablement” to correspond to the MW capacity that has been reserved for delivering ancillary service responses, if they are required, during a dispatch interval. We use this term to distinguish ancillary service activation from the concept of energy dispatch, which is energy that is planned to be delivered over a dispatch interval.



Having a shorter dispatch interval and introducing co-optimised ancillary services could exacerbate the problem as it will add additional complexity to spot market trading. In Phase 1, we recommended that to improve this situation there may be a role for PEMC to facilitate training for traders on physical market operations and suggested the training cover elementary micro economics and how to construct bids and offers to manage Pmin, start ups, energy limitations, contracts and market risks. In light of a shorter dispatch interval and introduction of an ancillary services market, we also recommend that the training include coverage of ancillary service market operations and electricity spot trading in ancillary services.

7.3 Market Participation and Operational Strategies

Table 12 summarises the average ancillary service nominations for 2012 for the generators that presently provide reserves.

Table 12 Average reserve nominations by generating unit and type of ancillary service for 2012

Generating Unit	REG		CON		DIS		TOTAL	
	Average over year (MW)	Average when scheduled (MW)	Average over year (MW)	Average when scheduled (MW)	Average over year (MW)	Average when scheduled (MW)	Average over year (MW)	Average when scheduled (MW)
1BINGA_G01	0	0	44	49	4	32	48	53
1MAGAT_G01	124	127	133	153	34	93	291	296
1PNTBNG_G01	0	0	16	40	41	86	57	82
3KAL_G01	19	85	1	85	2	180	21	90
3KAL_G02	20	85	2	85	3	180	24	91
3KAL_G03	15	85	3	85	2	180	20	91
3KAL_G04	22	85	3	84	2	180	28	88
Total	200		201		88		490	

We observe from this table that a small number of generators are largely dedicated to providing ancillary services. In particular, the Kalayaan pumped storage facility and Magat. Under a co-optimised energy and ancillary services market, these generators will be utilised for both energy and the ancillary services in a way that minimises the total costs on a dispatch interval by dispatch interval basis. This will likely result in changes to their reserve nominations and generation levels. They will therefore need to rework their operational strategies and bid accordingly into a co-optimised energy and ancillary service markets.

7.4 Operations of Fast-Start Plant

In the WESM there are a number of generators that are able to start at short notice, with start-up times of at most 15-minutes. Such generators are sometimes called as must-run units within the 1-hour period to alleviate network congestion or provide additional



voltage support. Under a shorter dispatch interval, these units can be directly operated in the market as energy services and will need to submit generation offers so they can be centrally dispatched. This can be achieved by the security constrained dispatch using the shorter dispatch interval.

7.5 Operations of Hydro with Small Storages

A shorter dispatch interval in combination with gate closure being removed will mean that hydros that have small storages will be able to manage their energy storages more efficiently. They will be able to refine their bidding strategies over shorter periods of time to manage their reservoir levels and inflows. A shorter dispatch interval should therefore lead to more efficient operations of hydros with small storages.

7.6 Bilateral Contracts

In section 3.3, we discussed the formation of trading interval prices from the dispatch interval prices and in section 3.5, the implications for energy settlements. This should not adversely change the incentives of a generator that is bidding optimally. In order to profit-maximise, they will continue to have an incentive to offer the quantity of energy over a trading interval at the short-run marginal cost.

7.7 Dispatch Instructions

Presently, most of the generators receive their hour-ahead targets via the MPI and are required (by the WESM Rules) to follow a linear trajectory to the next hour-ahead target:

3.8.4 Dispatched Trading Participants

Trading Participants who are dispatched shall use reasonable endeavors to achieve a linear ramp rate over the trading interval reach the target loading level by the end of that trading interval and within the dispatch tolerances specified in clause 3.8.7 and those Trading Participants will not be required to operate in any different fashion unless required to: (a) Respond in accordance with reserve or ancillary service contracts; or

(b) Respond to a direction in accordance with clauses 6.3 and 6.5.

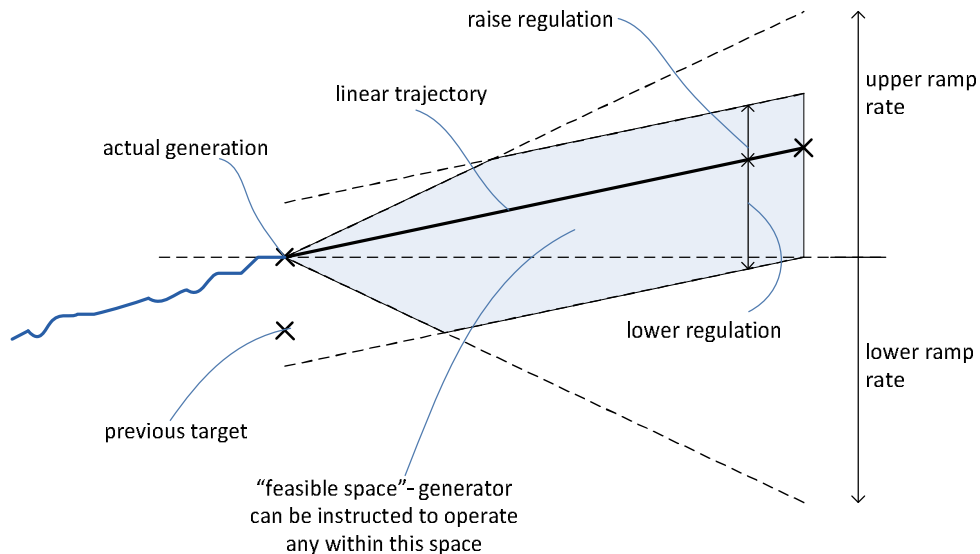
For the purpose of a shorter dispatch interval, the same concept of ramping linearly from one dispatch period can be maintained. The main implementation options for following dispatch instructions are:

- The generator's control system is directly interfaced to the AGC, which in turn is interfaced to the market. The AGC then communicates second-by-second dispatch instructions to the generator directly with targets adjusted to provide frequency regulation if the generator is enabled to provide regulation services; or
- The generator retrieves their dispatch instructions from the MPI and communicates them directly to the generator's control system or control room staff. The generators would need to adjust any systems built around an hourly MPI to work with more frequently published dispatch.



In all cases, it is important to ensure that the market clearing process and associated process within the AGC delivers physically feasible targets to the generators. The concept is illustrated in Figure 28. This relates back to the issue discussed in section 5.4 where the optimisation formulation for reserves needs to be carefully designed to ensure that both capacity and ramping limits are properly modelled for a range of energy and frequency control ancillary services. A generator may also consider incorporating some logic in their generation control systems to check that all dispatch targets are feasible and can be implemented.

Figure 28 Example of generator's feasible dispatch targets



7.8 Incentives for Following Dispatch Instructions

A shorter dispatch interval means that a generator deviating away from its target would only persist for a short period of time. But within a dispatch interval, the following would reduce the likelihood of generators materially deviating away from their targets:

- a phased-in Grid Code requirement to require all generators larger than say 30 MW to operate on AGC or otherwise be exposed to an SO management fee (as discussed in section 4.3);
- introduce automated non-conformance monitoring (as discussed in 4.8);
- incorporate some settlement logic into the settlements of regulation services to allocate a greater share of the costs of regulation onto those generators that materially deviate from their targets. This would replace the 50:50 split that is proposed in the PCRM; and/or
- exempt generators on AGC from making regulation payments.

7.9 Data Management

For a shorter dispatch interval, generators will need to enhance their IT systems to contain a greater amount of data and information. The increase in volume of data would depend on the dispatch interval, increases in the frequency of market processes (for example DAP), addition of new processes (HAD) and also on the number of ancillary service categories.

7.10 Summary of Market Participant Operations

The following summarises the main impacts on market participant operations that a shorter dispatch interval (and the proposed enhancements defined in sections 3, 4 and 5) would be expected to have:

- Spot trading with ancillary service markets, in addition to energy, will be more complex as market participants will need to reflect the technical capability of their plant to provide energy and a number of ancillary service services. This strengthens the arguments for:
 - reducing gate closure to enable participants to refine their strategies on a near real-time basis;
 - appropriately modelling the capability of plant in the market clearing engine to reflect joint capacity constraints and joint ramping limits;
 - providing training for market participants on not only optimal spot trading in energy, but expanded to include training on how to manage their plant when they are trading in multiple ancillary service markets;
- Generators that are mostly dedicated to providing ancillary services will need to eventually participate directly in market-based ancillary services and may need to rework their business strategies to be better able to operate in an environment that co-optimises energy and reserves;
- Fast start plant that are called upon as MRUs within the hour, under a shorter dispatch interval should offer directly into the market. Note that in the Phase 1 report, we outlined an approach for streamlining the MRU procedures and the associated payments.
- Hydros with small storages will be able to more efficiently manage their storages – an hour long dispatch interval in combination with a long gate closure makes it difficult for hydros with small reservoirs to operate efficiently.
- Generators that are not on AGC will need to actively monitor the MPI to update their dispatch instructions on a 5-minute or 10-minute basis;
- The main incentives for generators to follow their dispatch instructions are as follows:
 - a phased-in Grid Code requirement for all large generators to go on AGC;
 - automated non-conformance monitoring regime; and
 - (as a possible refinement to the PCRM) directing a greater portion of regulation costs to generators that have been assessed to deviate from their dispatch targets;



- Participants will have an increase in the data that they need to manage and/or monitor:
 - energy and ancillary service market offers;
 - dispatch interval data (5-minute or 10-minute) in addition to the hourly trading interval data; and
 - outcomes of HAD process and additional executions of the DAP (executed more frequently and for multiple scenarios).



8 Market Interfaces

8.1 Introduction

If a shorter dispatch interval were to be implemented there will need to be some modifications to a number of the existing market interfaces. While in the previous sections we have touched on some of the issues for the market interfaces, in this section we provide a more detailed review of the interfaces that would be impacted. Note that here we are concerned with the logical flow of information between MO, SO, Distribution Utilities (DUs) and Market Participants, with the focus on market operations⁵⁰ and issues that arise for a shorter dispatch interval. We defer discussion of the associated communications infrastructure and IT systems to section 9 and do not discuss interface issues that are not directly impacted by a shorter dispatch interval.

8.2 Impact of Shorter Dispatch Interval on Key WESM Interfaces

In terms of WESM operations, the key interfaces are between the MO, SO, DUs and Market Participants⁵¹. We illustrate this and the main information that needs to flow between these entities in Figure 29. For a shorter dispatch interval there will be a need for more timely delivery of information and a number of refinements to the existing interfaces. Furthermore, as discussed in sections 4 and 5, there will also be a need for the SO to manage more issues via the market rather than through actions taken within the hour. Therefore the interface between the MO and SO is becoming increasingly important the shorter the dispatch interval as it becomes the primary way in which the SO manages power system security and ancillary services.

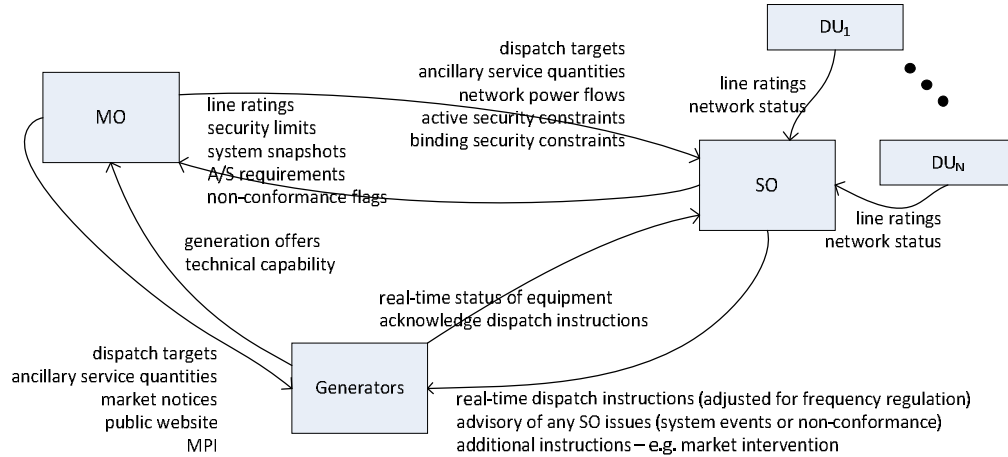
The interfaces between MO and Market Participants, the SO and DUs, and the SO and Market Participants will also need some refinements.

⁵⁰ We consider issues that arise on the short-term and as they related to near real-time market operations. Medium and/or longer term issues for example generator / transmission maintenance planning are not considered.

⁵¹ Note that we use “generators” and “market participants” interchangeably.



Figure 29 Interfaces between MO, SO, DUs and Market Participants for market operations



We outline the main changes that we have identified as being required in the subsequent sections.

8.3 MO to SO Interface

The entire set of inputs and outputs of the MDOM (or a replacement) should be transferred from the MO to the SO before the start of each dispatch interval. This enables the SO to transfer the content to online systems such as the EMS/AGC and/or a conformance monitoring system as well as to any displays the control room staff use for real-time operations. This communication of real-time data would most likely be managed by Inter-control Centre Communication Protocol (ICCP) software and servers. Using ICCP would allow both the SO and MO to be updated with real-time information on a 2 second cycle. It would also enhance the reliability of information transfers.

8.3.1 Dispatch Targets

A shorter dispatch interval means that the dispatch targets will be updated more frequently and the MOT should no longer be required. Ideally all dispatch targets would be communicated to the AGC, which would in turn communicate shorter-term (2-second) energy targets to the generators that are on AGC. However, not all generators are interfaced directly to the AGC. These generators will need to follow their targets via information collected from the MPI instead.

The dispatch targets should also be transferred to an online conformance monitoring system at the SO to systematically check for generator dispatch instruction conformance. Further discussion of these issues was given in section 4.2.

8.3.2 Frequency Regulation

Generators providing frequency regulation will change from one dispatch interval to the next. The SO will need to ensure that the adjustments made to energy dispatch targets for managing small frequency deviations will be consistent with the frequency regulation reserve quantities determined for each generator each dispatch interval. An approach

taken in other markets is to adjust the “participation factors” for each dispatch interval and constrain the dispatch targets of each generator to lie within their “feasible space” (a concept discussed in section 7.7).

In Figure 30 we outline the main elements of the approach that could be taken. The main aspects of the approach are as follows:

- Measurements of system frequency and time error are processed and filtered to determine the regulation requirement, $RR(t) = RR(t-\Delta) + FA(t)$, where $FA(t)$ is the additional MWs based on frequency and time error that need to be generated to return the system frequency back to nominal;
- The MO-provided market clearing engine solution is processed and the energy target for each generator is converted into a linear ramp trajectory for energy;
- Assuming that regulation raise and regulation lower are separate services, the participation factors are determined for generator i as follows:

$$RRPF = \frac{RE_i}{\sum_i RE_i} \qquad RLPF = \frac{LE_i}{\sum_i LE_i}$$

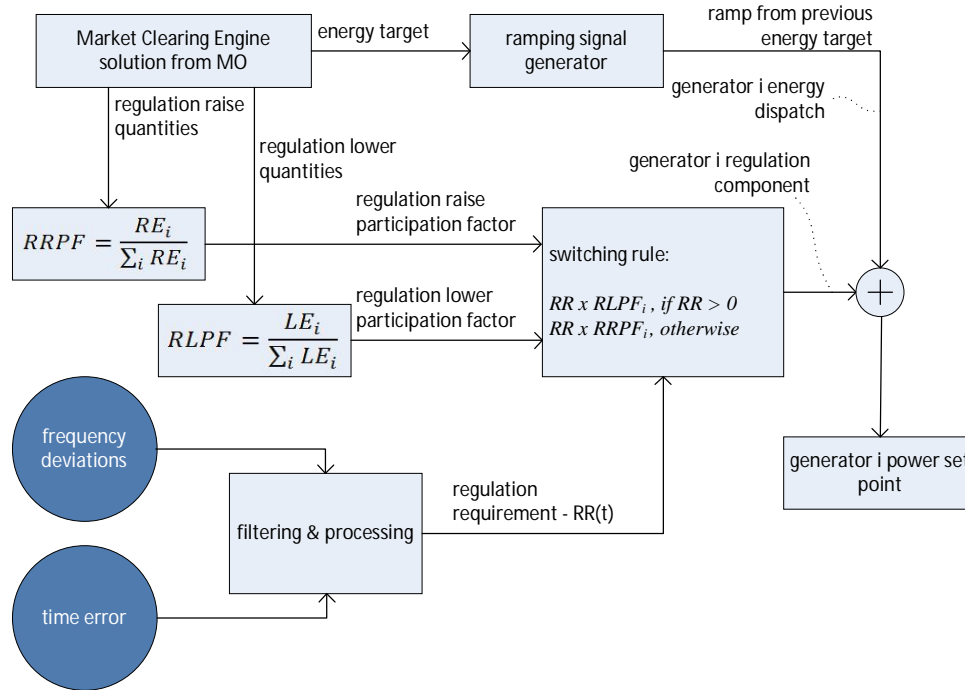
Where $RRPF$ = regulation raise participation factor, $LRPF$ = regulation lower participation factor, RE_i = regulation raise quantity for generator i , and LE_i = regulation lower quantity for generator i .

- Depending on whether raise regulation is needed or lower regulation, the regulation requirement, $RR(t)$ is multiplied by the respective participation factors and added to generator i 's dispatch target. Clearly a generator that is not providing regulation will be zero.
- The combined energy and regulation target is then communicated to the generator.

The approach outlined here could generally be implemented in the SCADA / EMS of the SO.



Figure 30 Determination of energy and frequency regulation dispatch targets during real-time operations



8.3.3 Contingency Reserves

The SO will need to monitor who is enabled to provide what contingency reserves, in order to:

- monitor the levels and check that they are reasonable for managing frequency; and
- in the event there is a contingency monitor the responses of generators enabled to provide the different categories of services.

This information would need to be managed via an online conformance monitoring system.

8.3.4 Power System Security

The market clearing process will determine a security constrained dispatch based largely on information provided by the SO, including the MNM, present state of all network elements (via snapshot files or SCADA), transmission line ratings and any additional security constraints. The SO should monitor as a minimum⁵²:

- Transmission line and transformer power flows and whether any transmission lines or transformers have been operated beyond their continuous ratings. Since transmission lines can only operate above their continuous ratings for a finite period of time, it may be necessary for the SO to advise the MO of any transmission lines

⁵² The issues listed here are just a subset of what the SO monitors; we focus primarily just on those issues relevant to a shorter dispatch interval.

that should no longer use the continuous ratings for dispatched flows or short-term ratings for the purpose of determining N-1 thermal security limits;

- Whether the power system is truly in a secure state – monitoring this is important as it could lead to identification of inaccurate or missing information that the MO could use to better dispatch plant;
- Security constraints that are active and/or that are binding (had an impact on dispatch and pricing in the market) as this will alert the system operator to the security limits that are critical; and
- Whether the market solution has unmet load as load rationing actions may be required by the SO.

8.4 SO to MO Interface

Presently, with a 1-hour dispatch interval, the SO manages a number of power system security related issues within the hour, using MRUs, the MOT or calling upon ancillary service providers. For a shorter dispatch interval, all of these intra-hour issues will need to be managed via the market⁵³.

8.4.1 System Snapshots

The SO already provides 5-minute power system snapshots to the MO. They include the real-time state of network elements, SCADA-measured generation levels and nodal demands. For a shorter dispatch interval the timely and reliable delivery of this data is critical. The use of a state estimator would reduce the occurrence of some errors and failures.

If not already, it would make sense to enhance the snapshot files to include short-term and continuous transmission line ratings, for the purpose of efficiently managing N-1 thermal security limits. They could be continuously monitored via the SO's SCADA system enabling some efficiency gains via dynamic ratings for the transmission lines.

8.4.2 Transmission Line Ratings

In section 4.5 we recommended that for a sufficiently short dispatch interval, the short term thermal ratings could be used as the basis of N-1 thermal security constraints. The SO will need to advise the MO of both the continuous and short-term ratings. If the SO monitors the dynamic ratings (adjusted for ambient conditions) then they could potentially be fed through to the MO via the snapshot files. As we saw in section 4.5 and 4.7, following a contingency, the power flow on a transmission line may exceed its continuous rating. In this case, the SO should advise the MO of the need to make adjustments to the thermal line ratings used to generate the thermal security limits.

8.4.3 Other Security Constraints

For a shorter dispatch interval, the SO will have less time to actively assess whether the power system is operating in a secure state and making adjustments to any additional security constraints that are required. We suggested that the SO therefore always be

⁵³ The SO will still be able to intervene and override dispatch instructions, but only in situations when the power system enters an emergency state or there are unusual power system conditions.



provided with the list of “active” security constraints (see section 8.3.4), and be provided with the means to easily deactivate them. Facilities for this are basically already in place, but we flag this as an issue because as it will be more important for a shorter dispatch interval.

8.4.4 Ancillary Service Requirements

The SO will need to advise the MO of the ancillary service requirements. However, if the approach that is taken for requirement setting is along the lines of that proposed in section 5.5 and section 6 then there is not much that the SO will need to do when the power system is in a normal state. In particular:

- For contingency reserve services (i.e. not regulation services), the requirements will either be co-optimised with the dispatch of energy and reserves (i.e. determined by the market clearing process which can trade off reserve requirements with the costs of energy and reserve dispatches) or computed directly from the system snapshot files (reflecting the largest credible net loss of generation and net loss in load in an ancillary services region); and
- For frequency regulation, if the probabilistic approach set out in section 6 were to be adopted, then the SO may only need to review the regulation requirements annually or in the event that there is evidence they are materially different to what is needed.

For situations where the power system is operating in an abnormal condition, the SO should have the right to be able to specify minimum levels of ancillary service requirements to be sourced from different network locations. This is particularly important in the event that islanding could occur.

8.4.5 Non-Conformance

As discussed in section 4.8, the SO will monitor non-conformance of the generators to dispatch instructions and/or whether they have provided the ancillary services they were supposed to. The SO would implement some largely automated logic that would keep track of dispatch target deviations and report back to the MO when there have been instances of generators non-conforming for either sustained periods of time or in cases where very large deviations have been detected. In the case of ancillary services, the SO will need to regulatory check the following (in real-time):

- Generators who are on standby to provide regulation are responding to AGC signals to provide regulation; and
- Generators on standby to respond to a contingency, provide responses when there is an event in the system.

And subsequently advise the MO and/or take intervention measures if needed to manage power system security.

This information should be sent back to the MO to take any corrective actions that may be needed. An example of this, in the event that the generator is not responding to dispatch instructions, would be to constrain the generator's dispatch target to be equal to its most recent measured generation level or current ramp rate. There may also be penalties applied to generators that are non-conforming either in energy or ancillary services.



8.5 Information Transfers between the SO and DUs

In Phase 1 we discussed that in order for the SO to properly manage power system security it is necessary to include in the MNM any elements of the sub-transmission network of any distribution utility that would materially improve the efficiency of WESM dispatching or pricing⁵⁴. For sub-transmission elements that fall into this category, the technical details of the sub-transmission network elements would be required along with the corresponding real-time measurements of the status of the network elements as well as the short-term and continuous equipment ratings. It is recommended that the SO's SCADA system be interfaced to any DUs for which this is the case. This will give the SO greater visibility of the transmission and sub-transmission network and will enable them to provide snapshots to the MO reflective of the present state of the transmission / sub-transmission networks for inclusion in the RTD process.

It may be necessary to amend the Philippines Distribution Code (PDC) to address this issue.

8.6 Market Participant Interface (MPI)

The main areas of the market participant interface that will need to be enhanced for information flows in the direction from market participants to the MO:

- Enable market participants to update their energy and ancillary service offers for inclusion in the next dispatch interval (we assume the gate closure duration is less than the dispatch interval duration; and
- Enhance generation offer structures and demand bids to enable:
 - ancillary service offers; and
 - specification of the technical capability for provision of energy and ancillary services (for example the “trapeziums” discussed in section 5.4 or some other way of specifying reserve capabilities).

Note that the existing formats for energy offers, where prices and quantities are specified for each trading interval, can be maintained. The only difference for a shorter dispatch interval is that a previously submitted energy (or ancillary service) offers can be superseded by updated energy / ancillary service offers for the next dispatch interval.

For information flows in the direction of the MO to the market participants, the following changes would be needed for a shorter dispatch interval:

- Energy and ancillary service quantities provided on a dispatch interval basis;
- Projections associated with HAD and DAP outcomes provided following their determination, as per section 3.8, to enable participants to make informed decisions on a short-term to medium-term period into the future;
- Dispatch interval prices; and
- Energy trading prices - as defined in section 3.3.

⁵⁴ For example, if network elements in the sub-transmission can be accurately reflected in the WESM's market clearing process, then it will lead to more efficient use of the network allowing lower-cost resources to be dispatched.



The MPI should provide facilities to obtain all the data that is otherwise publicly available through the public / web interface – see section 8.7.

8.7 Public / Web Interface

The public interface would need to be enhanced in a similar way to the MPI, with the main changes:

- Dispatch interval pricing and dispatch outcomes published for energy and ancillary services;
- Nodal energy trading prices to be published;
- Ancillary service trading interval prices to be published;
- Results of the HAD to be published;
- Results of all scenarios executed for the DAP to be published;
- All ancillary service market outcomes to be published;
- For generator energy and ancillary service offers:
 - Publish the final dispatch-interval energy and ancillary service offers that were used in dispatch and pricing; and
 - Publish every revision of every bid or offer that was submitted by all loads or generators.

These are likely to have implications for the volume of traffic on PEMC's website – an issue we pick up in section 9.

8.8 Information Transfers between the SO and Market Participants

For information transfers from the SO to market participants, the main enhancement required to support a shorter dispatch interval will be the issuance of dispatch targets that are reflective of the regulation quantities determined by the market, for those generators that are to provide frequency regulation. Being able to directly receive real-time generation targets from the SO's AGC/SCADA system would be a pre-condition for any generator wishing to participate in the regulation market.

For efficient operations when there is a shorter dispatch interval, it would be beneficial for key data from the generators to be sent to the SO such as real-time information on the status of the generator (online / offline), unit's rated capacity and ramp rates. The data could then be passed back to the MO via the snapshot files to facilitate in pre-processing of inputs for the market clearing process. For example, taking the more conservative of offered ramp rates vs. real-time ramp rates.

It would make sense to also monitor the quality of the data transfers between the SO and MO. For example, the MO could review the quality of the snapshot files and the SO could review the quality of the dispatch schedules. It is important to monitor that the data transfers are timely and that the quality of the data is sufficiently high.



8.9 Handling Information Delivery Errors and Failures

For an hourly dispatch interval, there is more time to overcome failures in delivery of information and/or detecting and correcting erroneous data transfers. For example, if the market solution was delayed by 10-minutes, then the SO could exercise some judgment and dispatch generators based on the MOT for the previous trading period. For a shorter dispatch interval, it will be more important to automate the handling of information transfer failures and introduce gracefully management of any erroneous data that may be detected. In respect to input data this might be assisted by the use of state estimation of key aspects of the power system.

While redundancy in communication networks and IT systems can minimise the likelihood of this problem occurring, failures can still occur, and it is not purely an IT issue as the treatment of missing data may have commercial consequences. Accordingly for a shorter dispatch interval, the procedures for handling missing and/or erroneous data need to be enhanced to ensure transparency in the event there are information transfer failures or errors.

Ideally the system state data which is to be transferred by ICCP from the SO to the MO should be calculated SCADA points based on some calculations that would provide sensible estimates whenever there is missing or bad data. If this is done then the MO does not have to do further checking of the data and possibly revise the data. An example of how SCADA data from the Australian NEM is managed (before it is used by the MMS) is as follows⁵⁵. SCADA data is used in the following order:

- manually substituted data may override “good quality” SCADA data (this has precedence because if an issue has been detected with certain SCADA measurements, the SO will be advised or be in the best position to determine appropriate alternative values and they will manually override bad quality data);
- good quality SCADA data;
- last dispatch run energy targets are used for the next dispatch run as a substitute for any SCADA data points that correspond to quantities that are scheduled;
- last good SCADA data value received is used for any quantities that are non-scheduled; and
- static default values for any non-scheduled quantities.

When SCADA data fails or there is a partial SCADA systems failure, it may be useful to flag those dispatch intervals for the purpose of performing some investigations at a later stage to understand the cause. It is important to develop a transparent market procedure that makes clear this aspect of data management and that addresses what happens in terms of market and system operations whenever critical element of the SCADA/EMS and/or MMS fail.

⁵⁵ This example has been taken from the Australian National Electricity Market, System Operation Procedures: SO_OP3706, “Failure of Market or Market Systems”, version 29, 30 November 2011. Available: www.aemo.com.au.



8.10 Market Interface Conclusions

This section has reviewed the interfaces between SO, MO, DUs and market participants with a view to identifying the areas that would be impacted by a shorter dispatch interval. The main conclusions are:

- MO to SO interface – the MO should deliver the following to the SO:
 - dispatch targets determined by the market clearing engine would be delivered to the SO's AGC and converted into linear ramps to be sent to generators – so generators on AGC are automatically sent their dispatch instructions (generators not on AGC will need to use the MPI);
 - frequency regulation quantities of generators should also be transferred to the AGC and used as the basis for regulation participation factors;
- SO to MO interface – the SO should provide the following to the MO:
 - the system snapshot files should be enhanced to include the short-term thermal ratings of the transmission lines and the transmission lines for which the SPS is applicable so that they can be correctly reflected in the market clearing engine;
 - access to all the key SCADA required for the dispatch optimisation, performance monitoring and demand forecasting via an ICCP connection;
 - list of any security constraints additional to be activated and list of security constraints to be deactivated;
 - ancillary service requirements;
 - generators detected under the ACMS to be non-conforming so that the MO can manage them appropriately in the market clearing engine;
- DU to SO interface:
 - the DUs should provide the details of the sub-transmission network for any parts of their networks that would materially enhance the efficiency of dispatch and pricing, these would be integrated into the MNM and handed to the MO;
 - the real-time status of circuit breakers and any sub-transmission network elements that the DU provides (the DU's and SO's SCADA systems could be directly interfaced to automate this);
- Market participant interface will need to be enhanced as follows:
 - interface for submitting offers enhanced to include offers for ancillary services;
 - enable generators to update bids and offers as required;
 - introduce concept of default bids and offers as an extension indefinitely into the future for each market participant;
 - provide results on a dispatch interval basis and on a trading interval basis;
 - extended to include projections of HAD and DAP outcomes;
- Public / Web Interface:
 - enhanced to publish dispatch interval outcomes;
 - enhanced to publish trading interval outcomes;
 - ancillary service market outcomes published;



- publish offers and bids; and
- Develop a market procedure to explain the details of any algorithms that handle errors in the transfer of snapshot files from SO to MO.



9 IT Systems

9.1 Introduction

As discussed in previous sections, introducing a shorter dispatch interval will have implications for a number of aspects of the WESM, including the existing IT systems of the MO, SO, market participants and some DUs. This section provides a high-level review of the systems and the impact that a shorter dispatch interval will have. Note that in this section we assume that a short dispatch interval, say a 5-minute dispatch interval, is adopted and also that the recommendations made in Phase 1 are adopted.

9.2 Required MO IT System Enhancements

9.2.1 Communications Infrastructure

We understand from discussions that the existing communications infrastructure in place in PEMC and between the MO and SO would be sufficient to enable a dispatch interval of 5-minutes but no shorter.

Nevertheless, we make the following comments on the MO's communication systems infrastructure requirements:

- Redundancy in communication networks for MMS-related transfers;
- Sufficient bandwidth to handle the increase in data traffic associated with a shorter-dispatch interval:
 - MO / SO data transfers (see sections 8.3 and 8.4) – we estimate the volume of data would need to increase by a factor⁵⁶ of about 100; and
 - MO / market participant data transfers via the MPI (see section 8.5) – the volume of data again could be expected to increase by a factor of 100, and sufficient to support not having a gate closure (so able to support continuous rebidding of market participants); and
- ICCP connection (with redundancy) to the SO's SCADA system to enable more reliable communication of the SCADA data from SO to the MO – we understand that the existing approach of sending snapshot files can sometimes result in 5-minute delays.

Usually the market's communication networks are set up so that there are dual-redundant SCADA networks and dual redundant dedicated market IT communication networks. These are usually provided by 1 or more communication service providers. All communications on these networks are dedicated to market operations, and not, for example, corporate IT systems, which are not as critical and for which a corporation network is generally established for the market operator.

Clearly testing targeted towards the communications infrastructure should feature as a significant part of the plan in enhancing the MMS to manage a shorter dispatch interval (and the other enhancements discussed in Phase 1).

⁵⁶ If a 5-minute dispatch interval were to be implemented, then it would mean that there would be 12 times the data per hour being required. Ancillary services will also increase the amount of data by a factor of at least 5 to 10, so estimate that the data volume to increase by about $10 \times 10 = 100$.



9.2.2 Market Clearing Engine

The market clearing engine would need to be able to handle the following additional requirements in addition to the functionality of the present MDOM (as a minimum):

- execution on a shorter dispatch interval, namely 5-minutes;
- ability to implement a co-optimised energy and ancillary services markets as discussed in section 5, of note is:
 - ability to represent a range of ancillary service categories (distinguished by their response times and separately for raise and lower services);
 - participants are able to offer for energy and any ancillary service categories they are capable of providing;
 - ability to have co-optimised or fixed reserve requirements;
 - representation of ancillary service regions;
 - joint energy and ancillary service capacity limits;
 - joint energy and ancillary service ramping limits;
- ability to generate N-1 thermal limits based on short-term and continuous ratings as discussed in section 4.5;
- automated handling of CVCs⁵⁷;
- implemented in a higher level optimisation language to enable continuous improvements in the market dispatch optimisation and enable changes to be made relatively quickly and at low cost;
- offline testing and development systems; and
- facilities for running aspects of the market in study mode.

In terms of performance the market clearing engine would need to be able to solve within 10's of seconds. Other requirements on the MMS IT systems, particularly as it pertains to the market clearing engine, were set out in section 10.6 of the Phase 1 report.

We observe that the existing MDOM would need to be either heavily enhanced to enable this to occur or be replaced entirely.

9.2.3 Centralised MMS Database

The MO's MMS database is presently designed based on hourly data. For a shorter dispatch interval, it would need to be revamped to manage 5-minute dispatch interval data as well as hourly data and to handle the following:

- ancillary service markets;
- dispatch and pricing outcomes, including constraint violation amounts, as distinct from settlement outcomes where energy trading prices would be used; and
- storing all revisions submitted by generators to their energy and ancillary service offers.

⁵⁷ Note that we mean here automatic detection of any non-zero violation variables in constraints and having a process of automatically relaxing the constraints to produce an appropriate pricing solution, as discussed in detail in the Phase 1 report.



All the software processes associated with transfers of data from one process to another will need to be enhanced accordingly. As for the communications infrastructure, the amount of data that would need to be managed can be expected to increase by a factor of about 100.

The hardware to support the Market Clearing Engine would need to set up so that there are separate and dedicated processors for each of the key market processes: RTD, HAD, DAP and WAP. There should also be redundancy across all of these to support fail-over and backup.

9.2.4 Settlements

The main enhancements would be as follows:

- compute the energy trading prices (ETPs) for each MTN, based on the 5-minute SCADA snapshot files, Site-Specific Loss Adjustment (SSLA) factors and the 5-minute dispatch and pricing outcomes;
- adjust settlement logic as described in section 3.5; and
- introduce ancillary service market settlements (payments to generators and cost recovery).

As noted previously the broader infrastructure for metering and computation of settlements need not be changed other than the inclusion of settlements for reserves.

9.2.5 MO / SO Interface

The MO / SO interface will need to be enhanced to address the issues identified in sections 8.3 and 8.4.

It is also recommended that the interfaces between different market processes that naming conventions and consistent file formats be introduced. For example, the market clearing engine should have well-defined input / output files that contain all the inputs necessary to execute the model and produce the outputs. This could be achieved through the use of XML files, which have the advantage of being also able to robustly handle changes over time to the interface. We observe that XML files are already in place for a number of the MO's systems – for example, the MPI.

9.2.6 MPI and Public (Web-Based) Interface

The MPI will need to be enhanced to address the issues identified in section 8.5 and the public (web-based) interface will need to be enhanced to address the issues identified in section 8.7.

9.3 Required SO IT System Enhancements

In summary the main SO IT system enhancements are:

- Adjust the AGC to follow outcomes of the market clearing engine, as described in section 8.3.2;
- ICCP connections:
 - connection to the MO to enable transfer of the SCADA information directly, rather than via the SCADA snapshot files;



- connections to market participants to communicate dispatch targets directly and retrieve real-time information about generators;
- SCADA measurements to be enhanced to include dynamic transmission line ratings and feedback to MO as basis of N-1 thermal security limits; and
- ICCP connection to the DUs⁵⁸ that have sub-transmission elements that would materially improve the efficiency of dispatch and pricing in the WESM.

9.4 Required Market Participant IT System Enhancements

The main impacts that a shorter dispatch interval will have on market participant IT systems are:

- Increased volume of data transfers to/from the MPI (by a factor of about 100);
- Increased volume of data for any databases (by a factor of about 100);
- Need to enhance bidding systems to manage ancillary services; and
- Requiring generators to go on AGC (or be subject to SO management fee);
- Requiring any other generators that want to participate in the frequency regulation market to go on to AGC.

The first four of these are largely unavoidable enhancements that all market participants would need to make.

9.5 Required DU IT Systems Enhancements

The main enhancement required for a select number of DUs would be interfacing their existing SCADA systems to the SO's SCADA system. This would probably, mainly involve an investment in communications infrastructure to support establishing an ICCP connection. At this time, there are only really 2 DUs for which this is likely to apply (MERACLO and VECO).

9.6 Approach for Phasing in a New MMS

Introducing a shorter dispatch interval and a reserve market are significant changes to the WESM. Given the commercial implications and the need to maintain the integrity of the market, it is paramount that a systematic and well-defined transition path is established as part of phasing in a new MMS.

The following are some high-level suggestions:

- Refine the MMS specifications to clearly address the new requirements (in particular, ensure that the issues raised in the Phase 1 and Phase 2 reports are reflected as well as to ensure that any shortcomings identified in the existing MMS are avoided);
- Develop and prototype a higher level dispatch and pricing mathematical formulation and requirements, an approach for doing this could be:

⁵⁸ As discussed in the Phase 1 report, including MERALCO's distribution network would make a material difference to efficiently dispatching the WESM.



- develop a mathematical formulation of the market dispatch optimisation similar to what has been implemented in Singapore⁵⁹
- implement the model in a higher level mathematical programming modelling language such as AMPL (www.ampl.com), AIMMS (www.aimms.com/aimms/overview), GAMS (www.gams.com), or GNU mathprog (www.gnu.org/software/glpk)
- Once a prototype has been developed, a range of market scenarios could be used to test the formulation and approach. This will inevitably lead to some fine tuning of the approach and revisions of the prototype. This could continue for several iterations before the model and approach are finalised.
- Having developed and tested a dispatch optimisation prototype should enable PEMC to negotiate effectively with any proposed vendors or possibly develop the system within PEMC and interface it to the vendor's infrastructure.
- Introduce the new (or substantially enhanced) MMS initially as a “shadow system” to the existing system (so there would be two systems operating in parallel for a period of time) so it can be thoroughly tested and transition to the new system carefully managed;
- Adequate redundancy introduced for all hardware, software, communications networks and staff;
- Project should set out a clearly defined set of phases and for each phase a set of pre-requisites that must be satisfied before advancing to the next phase. Some examples include:
 - communications infrastructure properly tested and confirmed to be adequate for the increase in bandwidth;
 - independent audit of the new / enhanced market clearing engine optimisation;
 - market participants confirm that they are able to interoperate with the new system (and have a process of addressing issues that may arise);
 - testing of real-time dispatch instructions being issued to generators;
 - 3 to 6 months of shadow system working in parallel without any major incidents prior to switching over to it;
 - testing of all fail-over, backup and redundant systems; and
- Adequate training of all staff.

9.7 IT Systems Conclusions

Enhancements will be required to the IT Systems of the MO, SO and market participants, in support of a shorter dispatch interval and the broader package of proposed enhancements recommended in the Phase 1 and Phase 2 reports.

The following is a summary of the main enhancements for the MO:

- Communications infrastructure:

⁵⁹ . The Singaporean formulation is in Appendix 6D to the Singapore Electricity Market Rules (<https://www.emcsg.com/marketrules>).



- ICCP connection between SO and MO for transfer;
- upgraded bandwidth to handle increase in data transfers by a factor of 100;
- sufficient redundancy in SCADA networks and WESM backbone networks;
- Market clearing engine model and supporting infrastructure enhanced to manage the Phase 1 and Phase 2 recommendations, which includes:
 - co-optimised energy and ancillary services;
 - ancillary services representation to reflect: reserve regions, optimised requirements, joint capacity limits and joint ramping limits,
 - automated handling of violated constraints;
 - thermal security limits based on short-term ratings;
 - implemented in a higher-level modelling language to enable refinements as market evolves;
 - production and pre-production environments;
 - sufficient offline systems to enable study-mode, concept testing and independent auditing;
- MMS database enhanced to reflect changes to market processes, shorter dispatch interval and to handle the outcomes of ancillary services market
- Settlement systems enhanced as follows:
 - determine energy trading prices and for settlements to be based on ex-ante trading prices and metered quantities;
 - ancillary service settlements introduced (based on the dispatch interval outcomes);
- MPI and public (web-based) interfaces:
 - enhanced to reflect additional data requirements from a shorter dispatch interval, introducing ancillary services, additional market process (HAD) and changes to the DAP;

The following are the main enhancements required for the SO:

- Enhancing AGC to take inputs from market clearing engine, determine linear energy targets for generators and regulation participation factors that reflect the outcomes of market-based ancillary services;
- ICCP connections between MO and SO and key DUs and SO;
- State-estimator to enhance quality of snapshot data or SCADA points transferred by ICCP and used in the dispatch optimisation or demand forecasting;
- Enhance SCADA snapshots to convey short-term thermal ratings of transmission lines and the status of the any critical sub-transmission networks of the DUs;
- Implement (or modify the existing) ACMS (see section 4.8);

Market participants:

- Adjust systems and communication links to MO to handle increased volume of data from MO;



- Qualifying generators or generators wanting to provide frequency regulation will need to go on AGC;

We also suggest that a careful plan be developed to ensure that the new (or substantially upgraded) MMS will be able to deliver the full spectrum of enhancements that are required in the WESM and such that the transition from the existing systems to the new systems is successful.



10 Options to Improve the WESM

10.1 Introduction

When assessing options to improve the efficiency of an electricity market it is easy to focus only on the market design. However, in reality, there are many successful markets which have a wide range of market designs varying from: cost based markets to bid/offer based markets with and without spot price caps, markets which have a single market price to ones which have nodal prices, markets which have an explicit ancillary services spot market to markets where all ancillary services are managed by the system and market operator, and so on.

It is not the market design alone that determines success or failure of an electricity market. It is very often market implementation and industry structure which have greater effects.

10.2 Successful Electricity Markets

For an electricity market to be successful it requires the following features:

- Appropriate market design (there are many reasonable designs): The design may simplify pricing but all designs must enable power system security to be managed and generators to be paid for services that they provide;
- Suitable industry structure;
- Suitable initial contracting arrangements and a suitable framework to facilitate a range of contracts and contracting arrangements;
- Effective implementation of market design, that is, effective implementation of the software, IT hardware and communications, market processes, provision of information, dispatch processes etc. All of these components need to work well and according to the market rules;
- Appropriate regulatory framework, for managing monopoly elements and tariffs for non contestable customers, that aligns with the market design, industry structure and future vision for the market. For instance there can be problems if the regulator is regulating contracts and tariffs in a way that is inconsistent with the competitive market's design;
- Generator, supplier and retail participants operating in the competitive areas of the market operating commercially and at arm's length from government's direct influence in their operations. This is often achieved in markets by privatising the electricity supply industry;
- Stability in the market arrangements, too many fundamental changes in a markets design create regulatory risk for participants;
- Confidence in market implementation and operation, the market and software used by the market operator should be periodically independently audited and the full audit report published;
- Publication of comprehensive and timely market information;



- A transition path to lead to the end goal of a fully competitive market with competition in generation and the supply of retail customers;
- Training for market participants, Market Operators, System Operators and regulators; and
- Ability for the market to evolve in an efficient way: that is the ability to change or adjust market rules, systems, contracts, etc. to end up with more efficient outcomes. All markets have to change over time, no matter how good were the initial design and implementation.

Not all market issues are necessarily related to market design. In our experience more of the issues relate to market implementation than design. In particular, before trying to fix up a market issue via a market rules change it is important to analyse why a problem is occurring. For example, is the problem due to:

- Poor implementation of the market design;
- Poor initial contracting arrangements;
- Poor management of legacy issues such as PPA's and take or pay fuel contracts;
- Inadequate training, knowledge or resourcing of industry participants;
- inconsistencies between system operations and market operations, and regulators; or
- Does the problem arise from an inappropriate industry structure?

In this sense, it can be seen that some market design issues require consideration of issues that may be broader than just the market clearing process or making adjustments to the market rules.

10.3 EPIRA

The Electric Power Industry Reform Act (EPIRA) was passed in 2001. The EPIRA was designed primarily to increase efficiency, enhance investment, broaden ownership, encourage competition in the power sector and to provide for orderly and transparent privatisation of the assets and liabilities of the National Power Corporation whilst ensuring the quality, reliability, security and affordability of the supply of electric power.

EPIRA's explicit objectives were:

- To ensure and accelerate the total electrification of the country;
- To ensure the quality, reliability, security and affordability of the supply of electric power;
- To ensure transparent and reasonable prices of electricity in a regime of free and fair competition and full public accountability to achieve greater operational and economic efficiency and enhance the competitiveness of Philippine products in the global market;
- To enhance the inflow of private capital and broaden the ownership base of the power generation, transmission and distribution sectors;
- To ensure fair and non-discriminatory treatment of public and private sector entities in the process of restructuring the electric power industry;



- f. To protect the public interest as it is affected by the rates and services of electric utilities and other providers of electric power;
- g. To assure socially and environmentally compatible energy sources and infrastructure;
- h. To promote the utilization of indigenous and new and renewable energy resources in power generation in order to reduce dependence on imported energy;
- i. To provide for an orderly and transparent privatization of the assets and liabilities of the National Power Corporation (NPC);
- j. To establish a strong and purely independent regulatory body and system to ensure consumer protection and enhance the competitive operation of the electricity market; and
- k. To encourage the efficient use of energy and other modalities of demand side management.

In any consideration of any changes in the WESM market design or implementation, the objectives c, d and k are particularly relevant. In the case of k, one of the ways of encouraging greater demand side management is to have firm ex-ante prices produced all of the time prior to the dispatch interval.

10.4 WESM Objectives

The WESM's objectives are defined in WESM Rule 1.2.5 which states:

The objectives of the spot market are to establish a competitive, efficient, transparent and reliable market for electricity where:

- a. *A level playing field exists among WESM Participants;*
- a. *Trading of electricity is facilitated among WESM Participants within the spot market;*
- b. *Third parties are granted access to the power system in accordance with the Act,*
- c. *Prices are governed as far as practicable by commercial and market forces; and*
- d. *Efficiency is encouraged.*

When considering any design or implementation changes to the WESM, the WESM objectives should be considered. In the case of looking at potential solutions for the Pmin, CVC and other related issues discussed in this report the last two objectives regarding prices and efficiency are particularly important.

10.5 Economic Efficiency

The aim of most electricity industry restructures and associated implementation of competitive electricity market arrangements is to improve the economic efficiency of the electricity sector. Economic efficiency has several dimensions: allocative efficiency, dynamic efficiency, and productive efficiency.

- **Productive efficiency** is achieved when whatever is being made is produced in the most efficient manner, that is, no change in the mix of inputs would result in increased output, given the current technological constraints. Alternatively, productive efficiency can be defined as using the least amount of resources to



produce a given good or service or output. That is, the good or service is being produced at the lowest possible unit cost.

In terms of the wholesale electricity market this concept translates into meeting demand at least cost given existing generation plant and transmission and distribution systems. For a wholesale electricity market this is equivalent to a least cost dispatch.

- **Allocative efficiency** is achieved when all mutually beneficial trades have been made, and all goods are in the hands of those who value them most. That is, no reorganisation of resources on the day can make anyone better off without making someone else worse off. All resources are allocated in a way that maximises the net benefit attained through their use.

A market is considered to be allocatively efficient if it is producing the right goods for the right people at the right price. Allocative efficiency is also referred to as Pareto Efficient Allocation.

A firm is allocatively efficient when its price is equal to its marginal costs. In the electricity industry, allocative efficiency requires that electricity be priced at a level which reflects its true costs to society, including any environmental costs. The WESM's design of locational marginal pricing is aimed at achieving this economic objective.

To achieve allocative efficiency, the WESM nodal spot prices should reflect the demand and supply situation at each node. If there is a scarcity of supply then the prices should be near the offer cap. If there is an abundance of supply then the prices should be near zero or negative. In general they should reflect the marginal cost of generation required to supply an extra MW of power at each node. The marginal costs should include the opportunity costs of limited energy resources such as water in storage for hydros, take or pay contracts for fuel supply and capacity constraints.

- **Dynamic efficiency** is the efficient allocation of resources over time. Achieving dynamic efficiency implies that new technology is adopted as it becomes economic. It also implies that new investments are made when the returns to society from the investment are greater than the returns from any other investment use. In the case of the WESM this translates to whether the right investments are being made on the demand and supply sides at the right times.

10.6 Suggested Options to Improve the WESM

Sections 3, 4, 5, 6, 7, 8 and 9 have reviewed a wide range of issues in the WESM through the lens of introducing a shorter dispatch interval. We observe that the enhancements span a range of areas that fall into two broader categories:

- WESM Rules and Market Operations; and
- Grid Code and System Operations.



We have therefore organised the options for enhancing the WESM in these categories. We assess the options in section 11, based on the framework we set out earlier in sections 10.2 to 10.5.

10.6.1 Proposals to Enhance the WESM Rules and Market Operations

The following are a summary of proposed options that could be taken to improve the WESM from a market rules and market operations standpoint. These would be necessary in support of a shorter dispatch interval:

- Introduce the concept of a dispatch interval (as distinct from a 1-hour trading interval⁶⁰). The proposal is to introduce the concept of a dispatch interval in the WESM Rules for the purpose of dispatch and pricing, while 1-hour trading intervals would be used for the purpose of energy market settlements.
- Implement a shorter dispatch interval. The proposal is to introduce a shorter dispatch interval of duration no longer than 15-minutes, with a preference for a 5-minute dispatch interval.
- Implement ex-ante pricing only (i.e. remove determination of ex-post prices). There are two mandatory pre-requisites for this: (1) dispatch interval of no more than 15-minutes is implemented and (2) automatic handling of the situation when constraint violations occur. See section 3.4 for more discussion. Define ex-ante energy trading prices to be the generation or load weighted average of the ex-ante dispatch interval prices.
- Revise settlements for energy for all market participants so that they are based on the ex-ante energy trading prices and (ex-post) metered quantities. Note that bilateral contracts continue to be netted out as is the present practice. Refer to section 3.5 for more detail.
- Shorten gate closure to say 30 seconds before the start of the next dispatch interval. The proposal is to effectively remove gate closure.
- Introduce an Hour Ahead Dispatch (HAD) process to be computed every dispatch interval as a 1-hour extension of the RTD. The intent is to guide the short-term decision-making of participants.
- Enhance the DAP process as follows:
 - execute DAP hourly;
 - extend horizon to always be 24-hours ahead;
 - remove expiration of standing bids / offers; and
 - implement DAP sensitivities (see section 9.18 of the Phase 1 report);
- Automate the management of constraint violations in RTD, HAD, DAP and WAP;
- Enhance the approach for short-term demand forecasting. The proposal is to introduce nodal demand forecasting for the RTD process as well as the proposed HAD process. This would involve developing a simple short-term time series demand

⁶⁰ Note that the distinction between a dispatch interval (for dispatching and pricing) and a trading interval (for market settlement) could be introduced without actually adopting a shorter dispatch interval.



forecasting model and using it to project demand for the next dispatch interval on a nodal basis and for the number of dispatch intervals necessary to support HAD.

- Enhance computation of N-1 thermal security limits. The proposal is to adjust the logic that N-1 thermal security constraints so that post-contingent power flows will be bounded by short-term thermal ratings rather than the continuous ratings. Refer to section 4.5, for a more detailed discussion.
- Introduce market-based ancillary services. The proposal is to introduce market-based ancillary service arrangements taking into account the issues set out in section 3.6 and section 5. In summary the proposed enhancements to the PCRM are:
 - Refine ancillary service categories to be a better match for a shorter dispatch interval and so that they correspond to technology-neutral and mutually distinct responses to frequency events;
 - Co-optimisation of energy and reserves;
 - Optimisation of ancillary service requirements for the subset of services where this can be done;
 - Zonal reserves pricing and cost-recovery;
 - Introduce joint capacity constraints and joint ramp rates to ensure that the combination of energy and reserve dispatches will be physically feasible;
 - Remove the requirement to “limit the schedule of a reserve provider to strictly one reserve category per interval”;
 - Remove the use of REFs in the PCRM; and
- Enhance the approaches used for the occurrence of missing or erroneous real-time data.

Note that a number of these proposals are interdependent and so it is not possible to take one without the other. Some are also dependent on the recommendations made in Phase 1. Rather than single out all the interdependencies for each of the options, we suggest that they be considered as a single package of enhancements that would be included in a new or substantially enhanced MMS.

10.6.2 Proposals to Enhance the Grid Code and System Operations

A shorter dispatch interval in the WESM will need a number of aspects of system operations to be enhanced. The following are a summary of proposed options that could be taken to improve the Grid Code and/or system operations. Strictly these are beyond the scope of the project and would need to be addressed via the GMC and process for making Grid Code changes. Nevertheless most are quite important and would be required to support a shorter dispatch interval:

- Directly use the generators shorter dispatch interval schedules instead of the MOT. Rather than the SO “dispatching” generators, the generators will be responsible for following their shorter dispatch interval targets. The SO will instead monitor their dispatch instruction conformance. Note that the issue of managing generators receiving dispatch instructions that are below their Pmins is up to the market participant to manage via their bids. With a shorter dispatch interval and reduced



gate closure period, the market participant will be able to quickly rectify the situation by the next dispatch interval by changing their generation offer.

- Introduce provisions in the Grid Code to make going on AGC mandatory for participants that are centrally dispatched and with capacity greater than a certain size, such as 30 MW. For an interim period the SO could charge a management fee as an incentive for generators to go on AGC sooner. All newly connected generators should be required to go on AGC.
- Set AGC participation factors to reflect outcomes of the frequency regulation services market outcomes. The proposal is for the SO to implement logic used in the AGC system for generators participating in the frequency regulation market. The logic would determine adjustments to those generator's energy targets to correct system frequency deviations and need to be consistent with the market outcomes for the respective dispatch interval. Refer to section 8.3.2.
- Enhance content of the system snapshot files. Proposal is to enhance the content of the snapshot files sent to the MO to include information on:
 - the real-time short-term and continuous thermal ratings of the transmission lines and transformers; and
 - information on the sub-transmission network elements of the DUs.
- Note that this proposal is dependent on the proposal recommended in Phase 1 to include key elements of the sub-transmission network of DUs in the dispatch and pricing (see Phase 1 report, section 9.16). It also requires any DUs with critical sub-transmission elements to supply real-time snapshots of the transmission network to the SO, communicated via ICCP as discussed in sections 8.5 and 9.5.
- This information would be used by the MO in the RTD and HAD processes to determine appropriate flow limits for network elements and determining the N-1 thermal security limits.
- Enhance management of power system security and ancillary services. Essentially a shorter dispatch interval will require the SO to use less intervention as compared to a 1-hour dispatch interval, and generally use market-based approaches for the following issues:
 - Determine appropriate short-term ratings for transmission lines and transformers and advise the MO appropriately so they can be used to manage post-contingent power flows in the N-1 thermal security limits;
 - Other power system security limits. The SO will need to advise the MO of any security limits above and beyond the N-1 thermal limits that are automatically generated by the MO's MMS, rather than intervene directly in dispatch, which should only occur if the power system enters an abnormal condition.
 - Advise the MO of the details of the transmission lines that are managed via the SPS. This is so that they can be properly reflected in the market dispatch and pricing model.
 - Ancillary service requirements. Depending on the approach taken, the SO will need to advise the MO of the requirements that are necessary and implement processes to determine the requirements. For regulation, we provide the outline



of an approach in section 6 for other reserve services, we suggest optimising the requirement, which means the SO will only need to advise the MO of system load relief factors. The SO should however, work with the MO to determine the most appropriate ancillary service regions.

- Enhance the management of MRUs to be more transparent, to reduce SO discretion and to be more market-based. The use of MRUs should generally seek to take a market-based approach for their management, as opposed to intervening on an ad-hoc / “as-needed” basis. This is discussed in detail in section 4.7 and in Phase 1 report sections 7 and 9.14.
- Enhance specification of frequency standards. Rather than base frequency standards on a deterministic criteria that is independent of the power system state, we suggest that the following approach be taken:
 - frequency standards are specified in a probabilistic manner, for example frequency within bounds 99% of the time;
 - use of wider frequency bands for the alert and/or emergency states compared to the normal state, for example, frequency following a contingency allowed to be within the range⁶¹: 59.2 and 60.8 Hz;
 - the need to return frequency back to the normal state following a contingency within a prescribed period of time (for example, 10 minutes following a contingency, system frequency is to return to the system normal state);
- Enhance compliance monitoring regime. The SO will need to monitor the following and advise the MO of any breaches:
 - Dispatch target following;
 - Whether frequency regulation was provided for any generator that is on frequency regulation;
 - Whether responses to power system events are consistent with the responses procured in the market-based ancillary service markets;
 - Whether the MO is recruiting too much or not enough ancillary services to maintain the power system in a secure state (as defined by the frequency standards in the Grid Code).
- The implementation of an Automatic Conformance Monitoring System (ACMS) would greatly enhance the SO’s ability to perform this (see section 4.8).
- Introduce expiration provisions in the ancillary service contracts that are to be renewed in the short-term, so that eventually all ancillary services that are market-based are managed via the market, as opposed to “out-of-market” commercial contracts.
- Harmonise Grid Code and Market Rules. As noted in section 4.9, there is some overlap in the operational aspects of the WESM Rules and the Grid Code, which could lead to confusion. The proposal is to harmonise the following aspects:
 - move the elements concerned with operations and management of power system security out of the Grid Code and into the WESM Rules. This would require a

⁶¹ This is strictly just an example – the SO would need to advise on what is appropriate.



detailed review into the areas of overlap between the two documents and is beyond the scope of this project;

- introduce consistent definitions for ancillary services between the Grid Code, WESM rules and PCRM; and
- ensure consistency between system operation actions and the priorities implied in the CVC penalty values (see Phase 1 report, section 4).

Many of these options need to be implemented in conjunction with those outlined in section 10.6.1.



11 Evaluation of Options

11.1 Introduction

The options for changes in the WESM design and implementation have been evaluated based on whether they are likely to:

- improve the efficiency of the WESM:
 - improve the efficiency of dispatch; and
 - improve price signals (better reflect marginal cost of meeting nodal demands and demand and supply balance);
- facilitate competition;
- enhance the prospects of new generation plant when required;
- result in a more transparent market; and
- ensure full compliance of the trading participants with the WESM Rules.

11.2 WESM Design Features

As discussed earlier, the key design features of the WESM are:

- it is an energy-only gross pool, that is there are no capacity payments and generators are expected to recover their costs through the energy market⁶²;
- the MO can net out standardised bilateral contracts⁶³;
- the dispatch interval is one hour;
- dispatch and prices are determined from an optimisation which is run every hour;
- spot prices are computed at each node (locational marginal pricing market);
- an ex-ante and ex-post pricing methodology is implemented to account for discrepancies between planned (ex-ante) and actual outcomes (ex-post):
 - generators are paid at the ex-ante price for their ex-ante scheduled generation and their deviations of actual generation versus the ex-ante generation are paid at the ex-post price and there is a similar arrangement for loads;
- the market is of a decentralised design in that generators are responsible for self-commitment decisions and need to manage any fuel or energy limitations via their offers and changes to their offers subject to gate closure of 1 hour ahead of the real-time;
- there is not a market price cap or floor but there is a bid cap (or offer price ceiling) of 62,000 P/MWh which is currently imposed on participants;

⁶² Even though the WESM is designed for both energy and reserves to be priced through the spot market, based on generator offers, demand bids and demand forecasts, this would still be classified as an energy only market because there are no capacity payments.

⁶³ The combined financial impact of PEMC netting out bilateral contracts in the WESM from participants' spot market payments combined with bilateral contract payments is that the cash flows correspond to ordinary spot market payments, standard two way contract for difference (CfD) payments plus payments for line rentals based on nodal price differences. Thus it would be quite possible to extend the netting out process to include other contract types such as one way CfDs.



- the market rules provide for the development of a financial transmission rights (FTR) regime but this has not been implemented;
- the rules provide for a reserve spot market to manage the market's regulation and contingency reserve requirements; and
- the WESM currently covers the grids of Luzon and Visayas, but not Mindanao.

Any decisions about changes in market design or implementation need to be compatible with the WESM's general design features, in particular the fact that the WESM is a decentralised market where decision making for unit commitment, management of storages and/or energy limitations is managed by market participants and not the MO or SO. Otherwise the rule change would be a major departure from the present design principles and would require revisiting the fundamental basis of the electricity market.

11.3 Analysis of Dispatch Interval Duration Options

In this report, we have analysed a number of issues related to the implementation of a shorter dispatch interval. Table 13 provides a basic summary of the key considerations for different dispatch interval durations. Based on this, our recommendation is to adopt a 5-minute dispatch interval, as it offers the greatest benefits and is feasible based on the existing, wider infrastructure that is in place in the WESM. This is also largely consistent with the dispatch interval duration used in other electricity markets, such as Australia, New Zealand, and an increasingly larger number of electricity markets in the USA.



Table 13 Analysis of dispatch interval duration options

Dispatch Interval Duration	Feasibility (IT Systems)	Regulation requirements	Transmission system utilisation
Less than 5-minutes	There would be a need for substantial upgrades in IT system infrastructure other than an upgraded MMS.	Significant reduction	Greater utilisation of transmission system due to use of short-term thermal ratings
5-minutes	Upgraded MMS required	Significant reduction (204 MW) compared to 1 hour trading interval	Greater utilisation of transmission system due to use of short-term thermal ratings
10-minutes	Upgraded MMS required	Significant reduction (157 MW) compared to 1 hour trading interval	Greater utilisation of transmission system due to use of short-term thermal ratings
15-minutes to 30-minutes	Upgraded MMS required	Reduction in regulation requirement is less significant	Unlikely to gain benefits of greater utilisation of transmission system
30-minutes to less than 1-hour	Upgraded MMS required	Minimal benefit	No benefit

11.4 Overall Recommendations (for Phase 1 and Phase 2 Combined) for the Market Rules and Market Implementation

The options to enhance the WESM presented in this report, in section 10.6, are dependent on a number of the recommendations made in the Phase 1 report. They also span aspects of system operations. Accordingly, we take the recommendations from the Phase 1 report and augment them with the recommendations in this report to present a single definitive list of the recommendations made across Phase 1 and Phase 2.

Note that the evaluation of the options here does not take into consideration the advantages or disadvantages of a day-ahead market (DAM). This discussed in the Phase 3 report.

Our recommended options for design and implementation changes to the WESM (across Phase 1 and Phase 2) being as follows for the WESM Rules and market operations:

- Set Pmin to zero in the market dispatch optimisation⁶⁴.

⁶⁴ Note that we use the term: "Set Pmin to zero" as a shorthand way of saying that the constraints in the market clearing engine (MDOM) that force generators to generate at or above their Pmin levels would set Pmin to zero. That is, the MDOM could dispatch a unit below its Pmin and to avoid this situation a generator would have to appropriately construct its bids and if it did occur to rebid in such a way as to remove this problem. We argue in Phase 1 that it is useful to maintain the Pmin constraints and maintain the ability to set Pmin to non-zero in order



- Changing the values and priorities of some of the CVCs and, perhaps, using a range of Nodal Value of Lost Load (VoLL) prices to facilitate orderly load shedding and rotation of load shedding.
- Set a market price cap and market price floor for the WESM.
- Set a bid floor price.
- Implement local PENs as an interim measure to automation of market re-runs.
- Automate the management of constraint violations in RTD, HAD, DAP and WAP, to eliminate the need to issue PENs.
- Shorten gate closure to say 30 seconds before the start of the next dispatch interval (essentially limit gate closure to the time at which the market clearing engine commences solving).
-
- Include DU's sub-transmission in dispatch and pricing:
 - include key sub-transmission of DU's in the MNM;
 - interface between SO and DU set up to convey real-time information on state of sub-transmission network; and
 - update the SO's snapshot files provided to the MO to reflect the state (and ratings) of the additional elements of the MNM.
- Improve the MRU arrangements for payment and interaction with the WESM.
- Introduce *dispatch intervals* as distinct from 1-hour *trading intervals*, where there is an integer number of *dispatch intervals* per *trading interval* and *dispatch intervals* are used for dispatching generation and loads and the *trading intervals* are used for energy settlements and DAP and WAP. The shorter dispatch interval essentially replaces the MOT and enhances pricing.
- Adopt a scheme of *dispatch interval nodal prices* and *trading interval nodal prices* for energy. The *trading interval nodal price* for a *market trading node* is the generation weighted or load weighted average of the corresponding *dispatch interval nodal prices* for that *market trading node*.
- Adopt a scheme of *dispatch interval regional prices* and *trading interval regional prices* for reserves. The *trading interval reserve price* for a *region* and *reserve category* is the regional requirement weighted average of the corresponding *dispatch interval regional reserve prices* for that *reserve category*.
- Adopt *ex-ante* pricing for energy and reserves. The *ex-ante* nodal energy price for each market trading node in any dispatch interval reflects the marginal costs of supply or in cases of supply shortage, the market price cap or in cases of excess supply, the market price floor (see Phase 1). The marginal cost of supply is determined from the shadow price of the energy balance equation or equivalent from the market dispatch optimisation model.
- The *ex-ante* regional reserve dispatch price for each market reserve region in each dispatch interval reflects the marginal costs of supply and is determined from the

to enable the SO to force generators to be dispatched to specific output levels in situations where it is necessary to direct generators.



shadow price of the relevant reserve requirement constraint or equivalent from the market dispatch optimisation model.

- Implement a dispatch interval of duration 5-minutes.
- Settlements for energy to be based on ex-ante nodal energy trading prices and metered energy quantities for all market participants (scheduled and non-scheduled).
- Ancillary service settlements based on dispatch interval prices and quantities. For consistency with market settlements for energy, they could be aggregated on an hourly basis.
- Enhance the DAP process as follows (refer to Phase 1 report):
 - execute DAP hourly;
 - extend horizon to always be at least 24-hours ahead; and
 - implement DAP sensitivities (see section 9.18 of the Phase 1 report);
- Introduce a HAD process as a 1-hour extension of the RTD with periodicity equal to that used for a shorter dispatch interval.
- Enhance the approach for short term demand forecasting to use nodal-based forecasts using a simple time series model. We make the observation that some research based on historical 5-minute SCADA snapshot data could be undertaken in order to determine the most appropriate time series model, calibrate them and assess their accuracy. Enhance determination of N-1 thermal security limits so that post-contingent power flows will be bounded by short-term thermal ratings rather than the continuous ratings.
- Allow some violation of N-1 thermal security limits when there is an armed load shedding scheme which could be used to prevent any overloading should a contingency occur.
- Introduce market-based ancillary service arrangements for frequency control (note that this has already been approved but requires new systems or system enhancements to manage more reserve and regulation services) but with the following WESM Rules / PCRM enhancements:
 - refine the categories of ancillary service to be more appropriate for a 5-minute dispatch interval;
 - co-optimisation of the provision of energy and reserves;
 - co-optimisation of the requirements of energy and contingency reserves;
 - base settlements of ancillary services on dispatch interval prices and quantities;
 - zonal reserves pricing and cost-recovery;
 - introduce joint capacity constraints and joint ramp rates to ensure that the combination of energy and multiple reserve dispatches will be physically feasible;
 - remove the requirement to “limit the schedule of a reserve provider to strictly one reserve category per interval”; and
 - remove the use of REFs.



- Establish a transparent procedure to address the issue of missing or erroneous real-time data and/or handle the IT system failures.

11.5 Overall Recommendations for Enhancing the Grid Code and System Operations

The following recommended options are applicable to the Grid Code and system operations:

- Dispatching enhancements:
 - use short-term dispatch targets instead of making adjustments based on MOT;
 - set AGC participation factors to reflect outcomes of frequency control ancillary service market outcomes for regulation;
- Power system security and ancillary services management enhancements:
 - Determine appropriate short-term ratings for transmission lines and transformers and advise the MO appropriately so they can be used to manage post-contingent power flows in the N-1 thermal security limits;
 - Advise the MO of the details of the transmission lines that are managed via the SPS. This is so that they can be properly reflected in the market dispatch and pricing model.
 - Other power system security limits. The SO will need to advise the MO of any security limits above and beyond the N-1 thermal limits that are automatically generated by the MO's MMS, rather than intervene directly in dispatch, which should only occur if the power system enters an abnormal condition.
 - Enhance the management of MRUs to be more transparent, to reduce SO discretion and to be more market-based.
 - Ancillary service requirements. SO will need to advise the MO of the requirements that are necessary and implement processes to determine the requirements.
- Enhance the content of system snapshot files, in particular:
 - real-time short-term and continuous thermal ratings of transmission lines; and
 - information on sub-transmission network elements of the DUs that would materially improve dispatch and pricing outcomes;
- Potential Grid Code enhancements:
 - make going on AGC mandatory for participants that are centrally dispatched and with capacity greater than a certain size, such as 30 MW. For an interim period the SO could charge a management fee as an incentive for generators to go on AGC sooner. All newly connected generators should be required to go on AGC.
 - require short-term thermal ratings to be determined for all transmission lines and transformers and for the MO to be advised of them for use in the market dispatch and pricing model;



- Enhance specification of frequency standards. Rather than base frequency standards on a deterministic criteria that is independent of the power system state, we suggest that the following approach be taken:
 - frequency standards are specified in a probabilistic manner, for example frequency within bounds 99% of the time;
 - use of wider frequency bands for the alert and/or emergency states compared to the normal state;
 - tighten the frequency band for the normal state;
 - the need to return frequency back to the normal state following a contingency within a prescribed period of time (for example, 10 minutes following a contingency, system frequency is to return to the system normal state);
- Harmonise the Grid Code and Market Rules with the areas requiring the most attention being:
 - move the elements concerned with operations and management of power system security out of the Grid Code and into the WESM Rules. This would require a detailed review into the areas of overlap between the two documents and is beyond the scope of this project;
 - introduce consistent definitions for ancillary services between the Grid Code, WESM rules and PCRM;
 - specification / determination of ancillary service requirements consistent between Grid Code, WESM rules and PCRM; and
 - ensure consistency between system operation actions and the priorities implied in the CVC penalty values (see Phase 1 report, section 4).
- Enhance system performance and compliance monitoring:
 - Whether dispatch targets were followed;
 - Whether frequency regulation was provided for any generator that is on frequency regulation;
 - Whether responses to power system events are consistent with the responses procured in the market-based ancillary service markets; and
 - Whether the MO is recruiting too much or not enough ancillary services to maintain the power system in a secure state (as defined by the frequency standards in the Grid Code).
-

11.6 Overall Design and/or Implementation Changes and Timeframes

Table 14 summarises the recommended design and implementation changes and the timeframe in which they can be undertaken for the areas that we have identified in Phase 1 and Phase 2. A number of the key suggested changes which are likely to bring substantial market benefits such as the shorter dispatch interval, automated market reruns, fully co-optimised reserves and better provision of information can't be properly implemented until PEMC has new or substantially upgraded systems.



Note that in the table we have described the type of change, with the following categories:

- Market rules – a market rules change would be necessary (there will also be associated market implementation changes, but this should be obvious);
- Market implementation – a market rules change is not strictly required, it is more of an implementation issue, involving existing and/or enhanced systems;
- Grid Code – a change to the Grid Code would be necessary;
- System operations – the SO would need to change their approach to system operations; and
- Interim measure – meaning that the change can be implemented, but would be superseded by other changes in the longer-term.

In Annex A we have provided a revised version of Chapter 3 of the WESM Rules that is reflective of the recommendations that impact the market rules from Phase 1 and Phase 2.



Table 14 Timeframes for recommended design and implementation changes (Phase 1 and Phase 2)

No.	Design or Implementation Change	Type of Change	Feasibility in the short-term	Longer Term ⁶⁵
1	Set Pmin to zero in market dispatch optimisation	No major market rules changes required (see Phase 1 report - section 10.5.1 Setting Pmin to zero).	Yes but SO would like a shorter dispatch interval	Yes
2	Changing the values and priorities of some of the CVCs	Market implementation	Yes	Yes
3	Set a market price cap and floor for the WESM	Market rules and market implementation	Yes	Yes
4	Set bid floor	Market rules and market implementation	Yes	Yes
5	Implement local PENs as an interim measure to automation of market re-runs	Interim measure	Only as a temporary measure	Not desirable in the long term
6	Automate management of constraint violations in RTD, HAD, DAP and WAP to avoid the need for issuing PENs for CVCs	Market rules (Phase 1 report - section 10.5.4 MRRs and PEN) and Market implementation	No	Yes
7	Shorten or remove gate closure	Market implementation	Yes but limited by 1 hour dispatch interval	Yes

⁶⁵ Requires a new or substantially enhanced MMS



No.	Design or Implementation Change	Type of Change	Feasibility in the short-term	Longer Term ⁶⁵
8	Include key elements of DU's sub-transmission in dispatch and pricing: <ul style="list-style-type: none"> include key sub-transmission of DU's in the MNM interface between SO and DU set up to convey real-time information on state of sub-transmission network update the SO's snapshot files provided to the MO to reflect the state (and ratings) of the additional elements of the MNM 	No market rule changes required ⁶⁶ (see Phase 1 report section 10.5.5 Include Key Elements of DU's) but changes to market implementation are required.	Yes	Yes
9	Improving MRU arrangements for payment and interaction with the WESM	Market implementation	Yes	Yes
10	Introduce dispatch intervals as distinct from 1-hour trading intervals	Market rules. Note that the price determination methodology (PDM) and PCRM would need to be revised.	Yes (the WESM rules could be adjusted to distinguish between dispatch and trading, with dispatch intervals set to 1 hour)	Yes
11	Implement dispatch interval of 5-minutes	Market implementation	No	Yes

⁶⁶ Although it may make sense to make the market rules more explicit in regards to the obligations on DUs that have sub-transmission networks that if included in the MNM would materially improve dispatch and pricing outcomes.



No.	Design or Implementation Change	Type of Change	Feasibility in the short-term	Longer Term ⁶⁵
12	Adopt a scheme of dispatch interval nodal prices and trading interval nodal prices for energy. The trading interval nodal price for a market trading node is the generation weighted or load weighted average of the corresponding dispatch interval nodal prices for that market trading node.	Market rules and implementation. Note that the price determination methodology (PDM) and PCRM would need to be revised.	No	Yes
13	Adopt a scheme of dispatch interval regional prices and trading interval regional prices for reserves. The trading interval reserve price for a region and reserve category is the regional requirement weighted average of the corresponding dispatch interval regional reserve prices for that reserve category.	Market rules and implementation. Note that the price determination methodology (PDM) and PCRM would need to be revised.	No	Yes
14	Adopt ex-ante pricing for energy and reserves. The ex-ante nodal energy price for each market trading node in any dispatch interval reflects the marginal costs of supply or in cases of supply shortage, the market price cap or in cases of excess supply, the market price floor (see Phase 1). The marginal cost of supply is determined from the shadow price of the energy balance equation or equivalent from the market dispatch optimisation model.	Market rules and implementation. Note that the price determination methodology (PDM) and PCRM would need to be revised.	No	Yes



No.	Design or Implementation Change	Type of Change	Feasibility in the short-term	Longer Term ⁶⁵
15	The ex-ante regional reserve dispatch price for each market reserve region in each dispatch interval reflects the marginal costs of supply and is determined from the shadow price of the relevant reserve requirement constraint or equivalent from the market dispatch optimisation model.	Market rules and implementation. Note that the price determination methodology (PDM) and PCRM would need to be revised.	No	Yes
16	Settlements for energy to be based on ex-ante nodal energy trading prices and metered energy quantities for all market participants (scheduled and non-scheduled)	Market rules and implementation. Note that the price determination methodology (PDM) and PCRM would need to be revised.	No	Yes
17	Ancillary service settlements based on dispatch interval prices and quantities. For consistency with market settlements for energy, they could be aggregated on an hourly basis	Market rules and implementation. Note that the price determination methodology (PDM) and PCRM would need to be revised.	No	Yes
18	Enhance determination of N-1 thermal security limits so that post-contingent power flows will be bounded by short-term thermal ratings rather than the continuous ratings.	Market implementation	No - requires shorter dispatch interval	Yes
19	Enhance the DAP process as follows (refer to Phase 1 report): <ul style="list-style-type: none"> • execute DAP hourly; • extend horizon to always be at least 24-hours ahead; and • implement DAP sensitivities (see section 9.18 of the Phase 1 report); 	Market implementation and system operations.	Some minor improvements could be made within the existing systems	Yes



No.	Design or Implementation Change	Type of Change	Feasibility in the short-term	Longer Term ⁶⁵
20	Introduce an Hour Ahead Dispatch (HAD) process to be computed every dispatch interval as a 1-hour extension of the RTD. The intent is to guide the short-term decision-making of participants.	Market implementation	No	Yes
21	Introduce market-based ancillary services for frequency control, with the following refinements: <ul style="list-style-type: none"> • refine ancillary service categories • co-optimize energy and reserves • co-optimize requirements of energy and contingency reserves • base settlements of ancillary services on dispatch interval outcomes • zonal reserves pricing and cost-recovery • joint capacity constraints & joint ramping constraints • remove requirement to limit schedules of reserve providers to one service only • remove REFs 	Market rules (including the PCRM), market implementation and system operations.	Possible for one or two services, but not recommended in the long term	Yes
22	Enhance approaches to manage occurrence of missing or erroneous snapshot data	Market implementation	Yes	Yes
23	Use nodal demand forecasting in RTD and HAD	Market implementation	No (needs shorter dispatch interval)	Yes



No.	Design or Implementation Change	Type of Change	Feasibility in the short-term	Longer Term ⁶⁵
24	Generator dispatching enhancements: <ul style="list-style-type: none"> • use short-term targets instead of the MOT • AGC participation factors to reflect regulation market outcomes 	Grid Code and System operations	No (since a shorter dispatch interval can only really be implemented with a new / enhanced MMS)	Yes
25	Power system security and ancillary services: <ul style="list-style-type: none"> • advise MO on use of short-term continuous ratings for management of post-contingent power flows • advise MO of transmission lines that are managed via the SPS so they can be better reflected in dispatch and pricing model • enhance approach for MRUs to be more market-based • enhance approach for ancillary service requirements 	Grid Code, system operations and market implementation	No (shorter dispatch interval is needed)	Yes
26	Enhance content of system snapshot files	System operations and market implementation	Yes	Yes



No.	Design or Implementation Change	Type of Change	Feasibility in the short-term	Longer Term ⁶⁵
27	Grid Code enhancements related to power system security management and system operations: <ul style="list-style-type: none"> • make going on AGC mandatory • require short-term thermal ratings to be determined for all transmission lines and transformers and advise the MO • introduce probabilistic frequency standards • generally harmonise Grid Code and WESM Rules, with particular focus on: (1) power system operations and market operations, (2) definitions of ancillary services, (3) determination of ancillary service requirements, and (4) system operation priorities and CVC values consistent. 	Grid Code and system operations	Frequency standard and Grid Code / Market Rules harmonisation could be done immediately. The use of less conservative ratings could be introduced; however, a shorter dispatch interval would be needed for the benefits to be gained.	Yes
28	Enhance system performance and dispatch compliance monitoring	Grid Code and System operations	Could be implemented, but not needed until there is a shorter dispatch interval and ancillary services market.	Yes
29	Improve training of traders	No changes required.	Yes	Yes



11.7 Comparison to Other Markets

To provide a simple comparison we have taken the WESM enhancements that were set out in Table 15 and drawn comparisons to the implementation of other similar markets in the region, that adopt the same decentralised market design philosophy.



Table 15 Comparison to other electricity markets

Market Design Feature	WESM (Current)	WESM (Recommended)	ANEM (Australia)	NEMS (Singapore)	NZEM (New Zealand)	PJM (USA)
Pmin	Constrain generators to at least their Pmin level when they submit generation offers	Remove Pmin constraints from market clearing	No concept of Pmin constraints	No concept of Pmin constraints	No concept of Pmin constraints	Real-time dispatch does not have Pmin, but there is a DAM to facilitate unit commitment
Market price cap / market price floor	Not any - bid cap only	Introduce market price cap and market price floor	Market price cap and market price floor for energy and all ancillary services	Market price cap and market price floor for energy and all ancillary services	No price ceiling or price floor	Not any - bid cap only
Bid cap / bid floor	Bid cap only	Introduce bid floor	Bid cap and bid floor	Bid cap and bid floor	Bid floor ⁶⁷	Bid cap only
Automated management of constraint violations	PENs and MRRs	Automate to produce prices in real-time based on marginal relaxation of constraints with non-zero violation variables	Automated (marginal relaxation approach)	Automated (marginal relaxation approach)	Automated (marginal relaxation approach)	Automated (a heuristic is invoked in real-time to estimate LMPs)
Gate closure	Nearly 2 hours	No gate closure (effective gate closure of say 30 seconds)	No gate closure (effective gate closure about 10 seconds)	65 minutes	2 hours	Day ahead at 18:00

⁶⁷ While there is no formal price cap or bid cap, there is an indirect one based on energy scarcity pricing arrangements.



Market Design Feature	WESM (Current)	WESM (Recommended)	ANEM (Australia)	NEMS (Singapore)	NZEM (New Zealand)	PJM (USA)
Distinction between dispatch periods and trading periods	No	Yes	Yes	No	Yes	Yes
Dispatch interval duration & purpose	SO manages within 1-hour period	MO implements 5-minute pricing and dispatch	5-minutes Pricing and dispatch	SO manages within 30-minute operations	SO dispatches on a 5-minute basis Market dispatch and pricing is on a 30-minute basis	Hourly day ahead pricing and 5-minutes real time pricing and dispatch
Trading interval duration & purpose	1-hour Pricing, dispatch & settlements	1-hour Settlements	30-minutes Settlements	30-minutes Pricing, dispatch & settlements	30-minute pricing and settlements	1-hour Settlements
Ex-ante and ex-post dispatch & pricing	Ex-ante dispatch and pricing & ex-post pricing	Ex-ante only	Ex-ante only	Ex-ante only	Ex-post pricing only	Ex-ante only
Ex-ante and ex-post settlement	Ex-ante prices, ex-ante schedules, ex-post prices and metered energy	Ex-ante prices & (ex-post) metered energy	Ex-ante prices & (ex-post) metered energy	Ex-ante prices & (ex-post) metered energy	Ex-post prices & metered energy	2-part settlements: day-ahead using ex-ante prices and scheduled energy, and real-time using ex-ante prices & (ex-post) metered energy



Market Design Feature	WESM (Current)	WESM (Recommended)	ANEM (Australia)	NEMS (Singapore)	NZEM (New Zealand)	PJM (USA)
Trading interval prices	No distinction between trading intervals and dispatch intervals	Trading interval energy prices based on dispatch interval prices	Trading interval energy prices based on dispatch interval prices	No distinction between trading intervals and dispatch intervals	Trading interval prices apply	Trading interval energy prices based on dispatch interval prices
Co-optimised reserves and energy	No reserves market in place	Yes	Yes but requirements are not co-optimised	Yes	Yes	Yes
Joint capacity & joint ramping limits for reserves and energy	N/A	Yes	Yes	Yes	Yes	Yes
Reserve providers may offer into and may be required to provide > 1 ancillary service?	No. Only allowed to provide 1 ancillary service per dispatch interval	Yes – remove restriction of only being allowed to provide 1 ancillary service at one time (provided ancillary service categories and constraints designed properly.)	Yes	Yes	Yes	Yes
Uses REFs?	Yes	No	No	Yes	No	Yes, in settlements only.



Market Design Feature	WESM (Current)	WESM (Recommended)	ANEM (Australia)	NEMS (Singapore)	NZEM (New Zealand)	PJM (USA)
Hour ahead dispatch process (or equivalent)	No	Yes – 1 hour ahead, executed every 5-minutes with 5-minute granularity	Yes – 1 hour ahead, executed every 5-minutes with 5-minute granularity	Yes – 6 hours ahead, executed every 30-minutes with 30-minute granularity	Yes – 4 hours ahead, updated every 30 minutes	Yes – 1 to 2 hours ahead, executed every 5-minutes with 5-minute granularity
Pre-dispatch or DAP process	Up to 24 hours executed every 4 hours for 1 scenario	24-hours ahead, executed every 1-hour for multiple scenarios (say 5 to 10 scenarios)	Up to 40-hours ahead, executed every 30-minutes for 44 scenarios	Up to 36-hours ahead, executed every 2-hours for 3 scenarios	2 days ahead, updated every 4 hours	24-hours ahead, hourly scheduling up to 60 minutes before real time
Dispatching generators	Use MOT to adjust within hour	For generators not providing regulation, provide 5 minute (dispatch interval targets) and have generators ramp linearly from target to target. Use AGC to track schedule generators providing energy + regulation quantities	Use AGC to manage generator real time targets and to manage joint energy + regulation quantities	Use AGC to manage scheduled energy + regulation quantities	SO issues dispatch instructions to generators determined by the SCADA/EMS	Market participants responsible for actual physical operation of plant to be as close as practical to desired output levels received from PJM



Market Design Feature	WESM (Current)	WESM (Recommended)	ANEM (Australia)	NEMS (Singapore)	NZEM (New Zealand)	PJM (USA)
Short-term demand forecasting approach	Hour-ahead nodal projections based on region-level hour-ahead forecast based on the latest 5-minute data available & adjusted for previous forecast errors	Nodal demand forecasts based on simple time-series model or equivalently effective method ⁶⁸	Artificial neural network for regional demand forecasts	PSO's EMS does system-level forecast, which is apportioned to nodes based on pre-determined "split" factors	SO provides demand projections to the MO. Note that the SO manages 5-minute dispatching using their own short-term projections ⁶⁹ .	EMS implements a forecast based on the similar day load forecast approach
AGC Policy	Optional	Mandatory	Mandatory	Mandatory	AGC is not used	Mandatory
Automated monitoring of conformance to dispatch instructions	Tolerance based on hourly energy	Yes. Automatically monitored by checking for large deviations & consecutive dispatch intervals of small deviations	Yes. Automatically monitored by checking for large deviations & consecutive dispatch intervals of small deviations	Yes. Automatically monitored by the market surveillance committee	Yes	Yes. Automatic checking of generation levels occurs.

⁶⁸ This would be recommended provided some research was carried out to test a range of possible time-series models, assess their accuracy and the accuracy was found to be reasonable. If simple time series based models were found to not produce accurate results, then other approaches could be explored.

⁶⁹ For greater detail on the methodology used in New Zealand, please refer to: http://www.systemoperator.co.nz/f5708,74342677/GL-SD-204_Load_Forecast_Methodology_and_Processes.pdf.



Market Design Feature	WESM (Current)	WESM (Recommended)	ANEM (Australia)	NEMS (Singapore)	NZEM (New Zealand)	PJM (USA)
Monitor ancillary service providers?	Presently no need for MO to do this as there is not an ancillary services market, SO monitors outcomes though	Yes – MO and SO should both monitor	Yes	Yes	Yes	Yes
Penalties for generators failing to provide ancillary services?	No	Yes	Yes	Yes	Yes	Yes
SCADA/EMS functions that are used by entity responsible for system operations	<ul style="list-style-type: none"> • Data acquisition • Supervisory control • AGC • State estimator (disabled) 	<ul style="list-style-type: none"> • Data acquisition • Supervisory control • State estimator • Online contingency analyser • Online optimal power flow • AGC (load frequency control) 	<ul style="list-style-type: none"> • Data acquisition • Supervisory control • State estimator • Online contingency analyser • AGC (load frequency control) 	<ul style="list-style-type: none"> • Data acquisition • Supervisory control • State estimator • Online contingency analyser • AGC (load frequency control) 	<ul style="list-style-type: none"> • Data acquisition • Supervisory control • State estimator • Online contingency analyser • Online optimal power flow • Economic dispatch 	<ul style="list-style-type: none"> • Data acquisition • Supervisory control • State estimator • Online contingency analyser • Online optimal power flow • Economic dispatch./ LMP Calculator • AGC (load frequency control)



Market Design Feature	WESM (Current)	WESM (Recommended)	ANEM (Australia)	NEMS (Singapore)	NZEM (New Zealand)	PJM (USA)
System snapshot files or system state information	Snapshot files sent from SO to MO	ICCP for SO and MO communications	SO and MO are combined, a software process retrieves SCADA measurements form the SCADA/EMS and delivers it to the dispatch engine. AEMO receives information from transmission companies and some generators via ICCP.	PSO provides real-time network snapshot files to EMC	SO manages real-time dispatching with key information provided to the MO	The real-time market and LMP computation process is embedded in the SCADA/EMS system.
Market-based ancillary service categories ⁷⁰	Not yet implemented	We have not specifically provided recommendations other than to consider raise and lower service categories and a variety of response times suitable for managing frequency in the WESM	<ul style="list-style-type: none"> • Raise 6 seconds • Lower 6 seconds • Raise 60 seconds • Lower 60 seconds • Raise 5 minutes • Lower 5 minutes • Regulation raise • Regulation lower 	<ul style="list-style-type: none"> • Regulation • Primary reserve • Secondary reserve • Contingency reserve 	<ul style="list-style-type: none"> • Instantaneous reserves • Instantaneous sustained reserves 	<ul style="list-style-type: none"> • Regulation • Synchronised reserves

⁷⁰ Note that we discuss only market-based ancillary services here. Those that are procured under long term contracts with the SO or that are not market-based are excluded.



Market Design Feature	WESM (Current)	WESM (Recommended)	ANEM (Australia)	NEMS (Singapore)	NZEM (New Zealand)	PJM (USA)
Market-based ancillary service cost recovery approach	Not yet implemented	PCRM approach is reasonable, but some refinements could be considered.	<ul style="list-style-type: none"> • Raise contingency service costs recovered from generators & apportioned by generation • Lower contingency service costs recovered from loads & apportioned by consumption • Causer pays methodology applies to regulation 	<ul style="list-style-type: none"> • Primary, secondary and contingency reserves recovered from generators based on runway cost allocation • Regulation is shared between generators and loads, with generator's portion being capped at first 10 MW generated 	Determined under ancillary service contracts.	Costs are recovered from load serving entities with different logic applying to the two categories of service



12 Costs and Benefits

12.1 Introduction

In Phase 1 we presented a cost and benefit analysis appropriate for a package of WESM enhancements. In this report, we have focused on issues relevant to a shorter dispatch interval, and in doing made the observation that a number of the Phase 1 recommendations need to be implemented in order for a shorter dispatch interval to be implemented (see Table 14). We therefore argue that the entire package of recommendations should be considered together. As such the cost benefit analysis from Phase 1 applies to the cost benefit analysis for the shorter dispatch interval. However, in our analysis we have identified some additional benefits and additional costs, so here we present a refined version of the analysis done in the Phase 1 report.

12.2 Benefits

The following is a summary of the benefits that we have identified (arising from the enhancements identified in both Phase 1 and Phase 2):

- reduction in capacity gap – more capacity offered to the market;
- reduced fuel costs as more expensive units may not be dispatched at all, rather than be dispatched to their Pmins;
- reduction in ancillary service costs due to shorter dispatch interval, co-optimisation of reserves and more accurate demand forecasts;
- greater ability for generators to manage their generation plant efficiently in the WESM;
- greater demand side participation because firm ex-ante prices delivered at the start of each dispatch interval;
- having most generators on AGC will lead to more accurate tracking of dispatch targets and greater competition to provide regulation services;
- greater utilisation of the transmission system;
- greater transparency in market operations; and
- given the above, greater encouragement of new entrants when they are required by the market.

We review each of these in the following subsections (mostly refining what was presented in Phase 1).

12.2.1 Capacity Gap

It was argued in the Phase 1 report that the capacity gap is a proxy for a number of dysfunctionalities and inefficiencies in the market. A reduction in the capacity gap means that more capacity would be offered to the WESM, enhancing competition, reducing dispatch costs, and increasing system reliability.

As discussed in the Phase 1 report, the WESM capacity gap is around 2700 MW (around 19% of the available capacity) with the largest contributors being oil plant: 940 MW and



hydro plant: 900 MW. If the new market arrangements resulted in say only 50% of this capacity being offered into the market then this would be like an investment in 470 MW of cheap diesel generation and 450 MW of hydro.

If we conservatively value this capacity at around US \$600 / kWh⁷¹ (25,000 PhP / kWh) it equates to a capital cost of about PhP 23,000 million (US\$ 552 million). If the lifetime is assumed to be 15 years and a discount of 10% real is used, then this corresponds to an annuity of PhP 3,024 million per annum (US\$ 72.6 million per annum).

12.2.2 Reduced Fuel Costs

As argued in the Phase 1 report (section 11.4) a lot of the potential fuel cost savings are appearing in the capacity gap.

12.2.3 Freeing-up Capacity otherwise dedicated to Frequency Regulation

In section 6.5 we found based on an analysis of 1-minute SCADA data that the regulation and load following requirement, that:

- for a 5-minute dispatch interval could be expected to be reduced from the present level of about 290 MW to 86 MW, which represents an additional saving of 204 MW; and
- for a 10-minute dispatch interval could be expected to be reduced from the present level of about 290 MW to 133 MW, which represents an additional saving of 157 MW.

Recall that at present, the SO takes capacity for ancillary services out of the market on the day-ahead and so it is unavailable for energy dispatch on a near real-time basis. If we apply the same logic to that used to value the capacity gap, then:

- for a 5-minute dispatch interval it equates to an annuity of US \$ 16.1 million per annum (PhP 671 million per annum); and
- for a 10-minute dispatch interval it equates to an annuity of US \$ 10.5 million per annum (PhP 437 million per annum).

The contingency reserve requirements are unlikely to change significantly as they reflect the size of the largest net loss in generation. Although introducing competitive arrangements for ancillary services with co-optimisation of energy and reserves can be expected to reduce the cost of procuring them.

The introduction of a transparent co-optimisation reserve market should substantially reduce the costs of meeting any reserve requirements. In Australia the introduction of a co-optimised reserve market reduced the costs of frequency control ancillary services significantly compared to what they were previously.

⁷¹ The cheapest capital cost for generation plant, listed in US Energy Information Agency "Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants", April 2013 (http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf), was \$US 676 / kWh for advanced combustion turbine. We believe Wärtsilä diesel engines would be a bit cheaper hence the use of the figure \$600/kWh.



12.2.4 Greater Demand Side Participation

Having firm ex-ante prices will encourage greater demand side participation in the market. How much this is worth in terms of economic benefits is uncertain.

12.2.5 Greater Utilisation of the Transmission System

A shorter dispatch interval in combination with representing the key elements of sub-transmission elements of the DUs in the market clearing and dispatch process will lead to more efficient use of the transmission system. A shorter dispatch interval should enable the use of short-term thermal ratings for management of post-contingent network power flows. This will enable greater utilisation of the transmission system with greater use of less expensive generators in areas of the network that are presently subject to constraints as well as reducing the occurrence of pricing outcomes affected by PENs. The precise savings are uncertain and have not been valued but they would be substantial as this would be approximately equivalent to getting another 10% of additional network capability.

12.2.6 Transparency

Having better processes for determining ex-ante spot prices and better “look-ahead” information in the form of HAD and DAP will make the WESM more transparent. It will also encourage generators to respond efficiently. This benefit has not been valued.

12.2.7 Encourage New Entry

The combination of all of the market enhancements should facilitate new entry of generation and suppliers when there is a market need or opportunity.

12.2.8 Reduction in Manual Costs for the SO

With a shorter dispatch interval, the SO should require less manual intervention to run the market. More aspects can be run automatically via the shorter market dispatch.

12.3 Costs

The following is a summary of the costs:

- for the MO:
 - cost of new or enhanced MMS;
 - cost of maintaining the new systems including support and maintenance fees and licenses fees;
 - IT hardware and communication system upgrades;
 - staff to implement and manage the new systems;
- for the SO (and a select number of DUs):
 - SCADA/EMS AGC enhancements;
 - ICCP connections to DUs;
 - conformance monitoring system enhancements;
- for market participants:
 - communications infrastructure to support increase in bandwidth;



- IT system enhancements to handle shorter dispatch interval; and
- cost of going onto AGC.

12.3.1 MO IT System Upgrade Costs

PEMC's costing for a new MMS upgrade in 2011 was found to be PhP 841 million. To allow for inflation and other refinements, we assume this to be PhP 1,000 million.

For maintenance and support and license fees, we allow for 20% of the purchase price. To cover for additional costs – for example, ad-hoc enhancements, additional staff and hardware, we add another 5% to this.

We therefore arrive at an extra PhP 250 million per annum.

Additional enhancements that we have identified as being required for the MO are:

- MO's communications infrastructure will need to support an increase in network traffic by a factor of about 100. We understand the existing infrastructure would be more than capable of supporting such an increase.
- PEMC's internal MMS database and storage capacity. This would be representing only a small investment in hardware and enhancements to the structure of the existing database.
- Enhancements to the MPI and public website. These are also likely to be modest enhancements that can be implemented with existing resources;

The costs of these items are all likely to be small relative to the MMS upgrade budget and they could be considered to be within the contingency allowance of 15% that is built in.

12.3.2 SO IT Systems Upgrade Costs

The SO's IT Systems are largely already in place and the main modifications are primarily concerned with:

- Additional interfacing (establishing ICCP connections to the MO and a small number of DUs); and
- Adjustments to the logic around the SCADA/EMS AGC system.

These changes can be done with existing resources and would be a relatively small cost compared to that of the MMS upgrade.

However, for inclusion in our analysis, we assume that the incremental cost to the SO is PhP 21 million (US\$ 500,000) with an ongoing cost of 25%.

12.3.3 Market Participant Upgrade Costs

As with the SO, we don't envisage the cost to market participants being particularly large as it primarily involves adapting existing infrastructure (databases and interfaces) to the new environment. The area that may require attention is whether the market participant communication links to MO are sufficient to support an increase in the volume of network traffic by a factor of 100.

For our cost benefit analysis we assume a total of 20 market participants, each having to invest PhP 21 million (US\$ 500,000) in upgrading their communications infrastructure. We also assume that there is an ongoing cost of 25% of the investment cost.



12.4 Net Benefit

Assuming that the Phase 1 and Phase 2 enhancements are made, and the dispatch interval is 5-minutes, then assuming the new MMS system has a life of 7 years we get the costs and benefits presented in Table 16. Based on this analysis the suggested WESM design and implementation changes supported by a new MMS for PEMC would have substantial net economic benefits, with a net present value of the order PhP 13.5 billion (US\$ 323 million). If we were to repeat the exercise with a 10-minute dispatch interval were to be implemented then the benefits would be of the order PhP 12.4 billion (US\$ 298 million).

Table 16 Net present value of costs and benefits of a new MMS for 5-minute dispatch interval in PhP 1,000,000

Year	Costs			Benefits		Net Benefit
	MMS	SO	MPs	Reduction in Capacity Gap	Reduction in Regulation Requirement	Total
0	-1,000	-21	-417	0	0	-1,437
1	-250	-5	-104	3,024	671	3,335
2	-250	-5	-104	3,024	671	3,335
3	-250	-5	-104	3,024	671	3,335
4	-250	-5	-104	3,024	671	3,335
5	-250	-5	-104	3,024	671	3,335
6	-250	-5	-104	3,024	671	3,335
7	-250	-5	-104	3,024	671	3,335
Present Value	-2,016	-42	-840	13,383	2,968	13,453



13 Conclusions

There are a number of market design and implementation changes that would appear to significantly enhance the efficiency, reliability, system security and transparency of the WESM. These have been outlined in this report with the focus being on a shorter dispatch interval. Given the interdependency with a number of Phase 1 findings, we presented a cost-benefit analysis that is inclusive of the issues identified in this report and those of the Phase 1 report. In doing so we have found that benefits of the market changes far exceed the costs of a new MMS and deliver a substantial net present value to the Philippines. These changes can only be supported by either a new MMS or a substantially enhanced MMS.

Our suggested way forward, is for PEMC to immediately implement the changes that can be done without procuring a new MMS that were identified in the Phase 1 report, and to begin to implement the necessary rule changes and specifications of a new MMS's capabilities for the longer term changes which were identified in the Phase 1 report and in this report. The specification of a new MMS should include a higher level formulation of the dispatch optimisation model and processes to ensure that effective co-optimisation of reserves and energy can be achieved and to ensure efficient treatment of constraint violations and market re-runs.

In this report, we have also identified a number of enhancements to the Grid Code and approach taken by the SO in undertaking system operations. Our recommendation in this regard is for the enhancements to be considered as part of a revised Grid Code and for system operation procedures to be enhanced accordingly.



14 References

PA Consulting Group "Philippine Electricity Market Corporation Process Review: Independent Operational Audit of the Systems and Procedures on Market Operations", 26 August 2011.

Deloitte and IES "Philippine Electricity Market Corporation Independent Spot Market Audit Report1on the Systems and Procedures of Market Operations", July 2010.

AEMO "Dispatch Constraint Violation Penalty Factors", 1 July 2010 -
<http://www.aemo.com.au/Electricity/Market-Operations/Dispatch/Dispatch-Constraint-Violation-Penalty-Factors>

AEMO "Constraint Relaxation Procedure", 2 September 2011 -
<http://www.aemo.com.au/Electricity/Market-Operations/Dispatch/Constraint-Relaxation-Procedure>

PHB Hagler Bailly Asia Pacific Limited and Freehill Hollingdale & Page "Discussion Paper on the Proposed Market Design & Governance Structure for the Philippines Wholesale Electricity Market" Prepared for Department Of Energy, Energy Regulatory Board, National Power Corporation, 2001.



15 Annex A: Proposed Revised Version of Chapter 3 of WESM Rules

The recommendations that we have made in Phase 1 and Phase 2, which are summarised in Table 14 require modifications to the WESM Rules. Nearly all of the changes occur in Chapter 3. This section sets out our proposed revisions to Chapter 3 of the WESM Rules. Note that this should be considered in the same way as any other rule changes that are submitted to the WESM rules change committee.

CHAPTER 3 THE MARKET

3.1 SCOPE OF CHAPTER 3

This chapter 3 sets out the rules which govern operation of the *spot market*, and related matters, including but not limited to:

- (a) The definition of the *market network model*, *pricing zones*, *reserve categories* and *reserve regions*, *dispatch intervals*, *trading intervals*, and *timetable*;
- (b) The procedures to be followed by *WESM members* in submitting offers, *demand bids* and data into the *spot market*;
- (c) The structure and use of the *market dispatch optimization model*;
- (d) The procedures for provision of *ancillary services* and for determining payment for those services;
- (e) The procedures for preparing *week ahead projections* and *day ahead projections*;
- (f) The procedures for *scheduling* and *dispatch*, *load shedding* and *excess generation*;
- (g) The determination of *market prices*;
- (h) The requirement relating to the publication of information, in accordance with the *timetable*;
- (i) The procedures for determining *settlements amounts* and for paying and receiving *settlements*;



- (j) The determination of *prudential requirements*; and
- (k) The procedures for supporting *transmission rights*.

All load forecasts and dispatch targets shall be specified in units of megawatt (MW) and will apply to the end of the relevant dispatch or trading interval unless otherwise stated.

3.2 MARKET NETWORK MODEL, TRADING NODES, AND PRICING ZONES

The *price determination methodology* contained in this *WESM Rules* shall be subject to the approval of *ERC*.

3.2.1 Market Network Model

- 3.2.1.1 The *Market Operator* shall maintain and *publish* a *market network model including all technical parameters*, which will be used for the purpose of central scheduling and dispatch, pricing and settlement.
- 3.2.1.2 The *market network model* shall represent fairly, and in a manner which will facilitate consistent and reliable operation of the power system:
 - (a) The *transmission network* under the control of the *System Operator*, and
 - (b) Such other aspects of the *power system* which, when *connected*, may be capable of materially affecting *dispatch* of *scheduled generating units* or pricing within the *spot market*.
- 3.2.1.3 The *market network model* may contain such simplifications, approximations, equivalencies or adaptations as may facilitate the *dispatch*, pricing, or *settlement* processes.



- 3.2.1.4 Where appropriate, the *Market Operator* or the *System operator* may recommend alterations to the *market network model*, so as to maintain:
- (a) The relationship between the *market network model* and the *transmission network*; and
 - (b) Consistency with *market* requirements, in accordance with clauses 3.2.1.2 and 3.2.1.3.
- 3.2.1.5 3.2.1.6 The *Market Operator* shall continuously adapt or adjust the representation of the *market network model* to accurately reflect *power system* conditions, within the relevant *market* time frames, as advised by the *System operator* under clause 3.5.3. The *Market Operator* shall *publish* any adaptations or adjustments to the *market network model*, which were used for the purpose of central scheduling and dispatch, pricing and settlement.

3.2.2 Market Trading Nodes

- 3.2.2.1 A *market trading node* is a designated point in the *market network model* where *energy* is bought or sold based on the schedules and prices determined by the *Market Dispatch Optimization Model*. A *market trading node* where *energy* is primarily sold into the *WESM* is referred to as the *generator node* while a *market trading node* where *energy* is primarily bought from the *WESM* is referred to as a *customer node*. [\(As amended by DOE DC No. 2006-01-0001 dated 10 January 2006\).](#)
- 3.2.2.2 Each *market trading node* defined under clause 3.2.2.1 shall:



(As amended by DOE DC No. 2006-01-0001 dated 10 January 2006)

- (a) Be assigned to a *Trading Participant* that intends to buy or sell *energy* and is capable of complying with the *dispatch* and *settlement* requirements in the WESM;
- (b) Be associated with a revenue *metering* and remote telemetering facilities capable of measuring all relevant incoming and outgoing energy deliveries for the purpose of *dispatch* and *settlement* in the WESM; and
- (c) As much as possible, represent the *connection point* between the *Network Service Provider* and the *Trading Participant*.

3.2.2.3 If the connection point of the *Trading Participant* could not be represented in the *market network model* or if a particular *market trading node* must be assigned to more than one *Trading Participant* because the conditions set in clause 3.2.2.2 are not met, the affected *Trading Participants*, the *Metering Services Provider* and the *Network Service Provider* will mutually agree on adjustments that will be implemented by the *Market Operator* and the *System operator*. (As amended by DOE DC No. 2006-01-0001 dated 10 January 2006)

3.2.2.3(A) Nodal Prices at Market Trading Nodes shall be used for the settlement of energy for both generators and customers.



(Added as per DOE DC No.2004-07-008 dated 7 July 2004)

- 3.2.2.4 The *Market Operator* shall maintain, publish, and continuously update a register of *market trading nodes*, defined in accordance with clause 3.2.2.1 so as to accurately reflect changes in the market network model and the *WESM member* responsible for each *market trading node*.

3.2.3 Customer Pricing Zones

- 3.2.3.1 Customer nodes may be grouped into customer pricing zones in accordance with the procedures to be developed by the Market Operator and subject to the approval of the PEM Board. The Market Operator shall maintain and publish the customer pricing zones to be used for the settlement of energy for customers. (As amended by DOE DC No. 2004-07-008 dated 7 July 2004)
- 3.2.3.2 All customers within a customer pricing zone shall face the same price for electricity consumed. (As amended by DOE DC No. 2004-07-008 dated 7 July 2004)
- 3.2.3.3 As long as customer-pricing zones are employed, the *Market Operator* shall conduct a periodic review and evaluation of existing customer pricing zones, and shall:
- (a) Submit revised customer *pricing zones*, to the *PEM Board* for approval; and
 - (b) *Publish* any revised customer *pricing zones* approved by the *PEM Board*.
- 3.2.3.4 The *Market Operator* shall, in consultation with *WESM Participants*, continuously review the procedures for determining the *market network*



model, market trading nodes, and customer pricing zones set out in this chapter 3 and, to the extent the *Market Operator* considers it to be reasonably necessary to promote the *WESM* objectives, the *Market Operator* may recommend changes to these procedures in accordance with the rule change process set out in chapter 8.

3.3 ANCILLARY SERVICES

3.3.1 Introduction

3.3.1.1 *Ancillary services* are services that are essential to the management of *power system* security, that facilitate orderly trading in electricity and ensure that electricity supplies are of an acceptable quality.

3.3.1.2 Without limitation, *ancillary services* may include

- (a) The provision of sufficient regulating *reserve* to meet fluctuations in load occurring within a *dispatch interval*;
- (b) The provision of sufficient contingency *reserve* to maintain *power system frequency*;
- (c) The provision of dispatchable reserve available to respond to a re-dispatch performed during a *dispatch interval*, on either a regular or an ad hoc basis;
- (d) The provision of reactive support to guard against *power system* failure; and
- (e) The provision of black start capability to allow restoration of *power system* operation after a complete failure of the *power system* or part of the *power system*.



3.3.1.3 The requirements for *ancillary services* are to be met in the following ways:

- (a) By the *System Operator*, in consultation with the *Market Operator* and *WESM Participants*, setting minimum standards in relation to technical performance specified in the *Grid Code* and *Distribution Code* which requires some level of *ancillary services* to be provided by *Ancillary Services Providers*;
- (b) By the *System Operator* purchasing *ancillary services* in accordance with clause 3.3.3.

3.3.2 Ancillary Services Contracting by the System operator

3.3.2.1 The *System operator* shall use reasonable endeavors to ensure that sufficient facilities are available and operable to provide for:

- (a) The maintenance or restoration of *power system security* under *emergency* conditions;
- (b) The restoration of all or any part of the *power system* to its satisfactory operating state, following an *emergency*, threat to *system security* or *force majeure* event; and
- (c) The availability, at all times, of the number of independent power sources able to provide black start-up facilities, determined in accordance with the procedures developed by the *Market Operator* to ascertain the quantities of *ancillary services* which the *System operator* shall purchase.



- 3.3.2.2 The *System operator* shall use reasonable endeavors to enter into *ancillary services* agreements to provide sufficient *ancillary services* to meet the requirements of clause 3.3.2.1, subject to clause 3.3.3.

3.3.3 Ancillary Services Agreements

- 3.3.3.1 The *System operator* shall arrange for the provision of adequate *reserves* for each region in accordance with clause 3.3.3.2.
- 3.3.3.2 The *System operator* shall arrange for the provision of adequate *ancillary services* for each region either:
- (a) By competitive tendering process, administered by the *Market Operator*, whereby a number of *Ancillary Services Providers* can provide a particular category of *ancillary services*; or
 - (b) By negotiating contracts directly with an *Ancillary Services Provider* who is a *Direct WESM member*, where only one *Ancillary Services Provider* can provide the required *ancillary services*; or
 - (c) Where applicable, by competitive *spot market* trading in accordance with clause 3.3.4.
- 3.3.3.3 The *System operator* shall negotiate any *ancillary services* agreements with *Ancillary Services Providers* who are *Direct WESM members* on commercial terms acceptable to the parties and at arms length, subject to clause 3.3.3.2.
- 3.3.3.4 Payment for *ancillary services* purchased under an *ancillary services* agreement may include:



- (a) A payment for both contracted capabilities and a measure of the *ancillary services* provided;
- (b) A demonstrable *spot market* opportunity cost, that is lost *spot market* revenue or opportunity costs incurred by the *Ancillary Services Provider* as a result of providing the *ancillary services*;
- (c) A fair return to the *Ancillary Services Provider* in respect of any additional direct costs associated with providing the *ancillary service*;
- (d) When applicable, subject to clause 3.3.4.1, a price for that ancillary service established by a competitive *spot market* mechanism.

3.3.3.5 Payments for *ancillary services* that are provided are to be made by the *Market Operator* via the *settlements* system in accordance with clause 3.13.14.

3.3.3.6 *Ancillary services* agreements shall contain a provision pursuant to which the capability of the relevant *Ancillary Services Provider* to provide *ancillary services* shall be demonstrated from time to time to the satisfaction of the *System operator* according to the standard test procedures established under the *Grid Code* and *Distribution Code*.

3.3.3.7 Any dispute between the *System operator* and the *Ancillary Services Provider* in relation to the determination of a payment for spot market *ancillary services* shall be determined by the *Dispute Resolution Administrator* in accordance



with clause 7.3, unless otherwise provided in the *Ancillary Services Procurement Agreement (ASPA)*. (As amended by DOE DC No. 2012-02-0001 dated 15 February 2012)

3.3.4 Reserve Market Arrangements

3.3.4.1 When reasonably feasible, the *Market Operator*, in coordination with the *System operator*, shall establish and administer a *spot market* for the purchase of certain reserve categories.

3.3.4.2 The *reserve categories* to be traded in the *spot market* shall include:

- (a) *Regulating reserve*, being the ability to respond to small fluctuations in system frequency including but not limited to fluctuations caused by load fluctuations;
- (b) *Contingency reserve*, being the ability to respond to a significant decrease in system frequency including but not limited to a decrease in system frequency in an interconnected AC network as a result of a credible contingency affecting one (or more) *Generation Companies* within that *network*, or *transmission* flows into that *network*; and
- (c) Other *reserve categories* as may from time to time be proposed by the *Market Operator*, in consultation with the *System operator*, and with *WESM members*, and approved by the *PEM Board*. *Reserve categories* should be defined so that they correspond to mutually distinct responses to increase or decrease system frequency with



different response timeframes and chosen to be technology neutral to allow responses from any facility (load or generator) able to provide the requisite response.

- 3.3.4.2B The *Market Operator* and *System operator* will, in consultation, determine an appropriate set of reserve regions that will be used for the purpose of setting reserve requirements, determining reserve prices and recovering reserve costs.

3.3.5 Ancillary Services Cost Recovery

- 3.3.5.1 The *System operator* shall maintain and *publish reserve cost recovery zones* within which *reserve cost recovery charges* may be recovered to meet each locationally specific requirement.

- 3.3.5.2 The costs of ancillary services are to be recovered through the settlement amounts calculated by the *Market Operator* under clause 3.13.10:

- (a) In accordance with the cost recovery formula to be developed by the *System operator* for the categories of reserve which are defined in clause 3.3.4.2; and
- (b) From those *WESM members* or others on whose behalf the *System operator* is deemed to purchase each *ancillary service*, in proportion to the benefits which are considered to be derived by those *WESM members*, in respect of *ancillary services* not included in clause 3.3.5.2 (a).

- 3.3.5.3 The costs of providing each locationally specific reserve requirement shall be allocated by the *Market Operator* to those *Trading Participants* in the relevant *reserve cost recovery zone* in the form



of *reserve cost recovery charges* to be determined in accordance with the principles set out in clause 3.3.5.4.

3.3.5.4 When allocating *reserve cost recovery charges* to *Trading Participants* in a particular *reserve cost recovery zone* as published in clause 3.3.5.1 the *Market Operator* may recover:

(a) The cost of *regulating reserve*, in each *reserve cost recovery zone*, from:

(1) *Customers* with *load facilities* connected in that *reserve cost recovery zone*, under a formula which shall account for both the relative size of the *customer loads*, and the degree to which they contribute to deviations from their schedule within the *trading interval*; and

(2) *Scheduled Generation Companies* with *generating systems* connected in that *reserve cost recovery zone* under a formula which shall account for both the relative size of the *generating systems*, and the degree to which they deviate from dispatch instructions,

(b) The cost of *contingency reserve*, in each *reserve cost recovery zone*, from:

(1) *Generation Companies* with *generating systems* connected in that *reserve cost recovery zone*; and



- (2) *Network Service Providers* serving that *reserve cost recovery zone*, under a formula which accounts for the relative size of the relevant *generating system* and *distribution network*, their *reliability*, and the impact which failure may have on conditions within that *reserve cost recovery zone*.

3.3.6 Provision of Ancillary Services

- 3.3.6.1 An *Ancillary Services Provider* shall not unreasonably refuse to provide *ancillary services*.
- 3.3.6.2 When justifiable in terms of *power system security*, the *System operator* may direct any *Ancillary Services Provider* to provide an *ancillary service* in accordance with the *Grid Code*.

3.3.7 Approval, Periodic Review and Evaluation of Ancillary Service Arrangements

- 3.3.7.1 The *System operator* of TRANSCO shall charge user fees for *ancillary services* to all electric power industry participants or self-generating entities connected to the grid. Such fees shall be fixed by the *ERC* after due notice and public hearing.
- 3.3.7.2 The *System operator*, in consultation with *Market Operator* and *WESM Participants* shall conduct a periodic review and evaluation of the following:
- (a) *Ancillary services* categories, *ancillary services* arrangements and *ancillary services cost recovery formula*;
 - (b) *Reserve categories*, *reserve regions*, and locationally specific *reserve requirements*; and



- (c) Procedures developed under this clause 3.3 with a view to refining these procedures to promote the *WESM* objectives and better meet the requirements of the *power system* operation.

3.3.7.3 Any proposed changes to the *ancillary service* categories, *ancillary services* arrangements, *ancillary services cost recovery formula*, *reserve categories*, *reserve regions* or locationally specific reserve requirements that will affect the fees of *ancillary services* shall be filed by the *System operator* of *TRANSCO* with the *ERC* for approval.

3.3.7.5 Any proposed changes in the procedures reviewed under this clause 3.3.7 shall be approved by the *PEM Board* in accordance with the rule change process set out in chapter 8.

3.4 MARKET TRADING INTERVAL, DISPATCH INTERVAL AND TIMETABLE

3.4.1 Trading Intervals

3.4.1.1 A *trading interval* is defined to be a period of duration one (1) hour, commencing on the hour.

3.4.1.1A *Trading intervals* will be used for the purpose of week ahead projections, day ahead projections, determining *energy settlement prices* in accordance with clause 3.10.9 and determining *energy settlements* in accordance with section 3.13.

3.4.1.2 Only *energy* shall be traded during the interim *WESM*. Trading in *ancillary services* shall be implemented upon commencement of the *spot*



market for ancillary services established under clause 3.3.4.

3.4.1A

Dispatch Intervals

3.4.1A.1 A dispatch interval is defined to be a five (5) minute period.

3.4.1A.2 The *market dispatch optimization model* defined in section 3.6 will be run by the Market Operator for each *dispatch interval*. If the *market dispatch optimization model* is not successfully run for any *dispatch interval*, then the values of the last successful run of the Market Dispatch Optimization Model must be used for that dispatch interval.

3.4.1A.3 *Nodal energy dispatch interval prices* for energy and *dispatch interval prices for each ancillary service and each ancillary service region* will be determined for each *dispatch interval*.

3.4.1A.4 *Energy settlement prices* for generation *market trading nodes* will be based on the *nodal dispatch prices* and nodal generation measurements for each trading interval in accordance with clause 3.10.9.

3.4.1A.5 *Energy settlement prices* for load *market trading nodes* will be determined based on the *nodal dispatch prices* and nodal load measurements for each trading interval in accordance with clause 3.10.9.

3.4.2 Timetable

3.4.2.1 The *Market Operator* shall operate the *spot market* in accordance with the *timetable*.

3.4.2.2 The *timetable* shall include the schedule and procedure for the following:



- (a) Determining and *publishing week ahead projections* for each trading interval including precise specification of the *market horizon* to be used for such projections;
 - (b) Determining and *publishing day ahead projections* for each trading interval including precise specification of the *market horizon* to be used for such projections;
 - (b1) Determining and *publishing hour ahead projections* for each dispatch interval including precise specification of the *market horizon* to be used for such projections;
 - (c) Submitting offers, bids and data; and
 - (d) If necessary, for any other action to be taken by the *Market Operator*, the *System operator*, or any *WESM member* during the operation of the *spot market*.
- 3.4.2.3 The *Market Operator* shall maintain, *publish* and continuously update the *timetable*.
- 3.4.2.4 Any proposed changes in the *timetable* and related procedures shall be approved by the *PEM Board* in accordance with the rule change process set out in chapter 8.

3.5 SUBMISSION OF OFFERS, BIDS, AND DATA

3.5.1 Communications of Offers and Bids

Each *Trading Participant* shall provide to the *Market Operator* the information required under this clause 3.5 in accordance with the electronic communication procedures.

3.5.2 Network Service Provider Data



- 3.5.2.1 Each *Network Service Provider* shall submit to the *System operator* standing *network data* relating to all network elements which are under that *Network Service Provider's* control and included in the *market network model*, in accordance with clause 3.5.2.4 and the *Grid Code and Distribution Code*.
- 3.5.2.1A Each *Network Service Provider* will submit to the *System operator* any planned outages of network elements which are under that *Network Service Provider's* control and that are included in the *market network model*.
- 3.5.2.1B Each *Network Service Provider* will submit to the *System operator* in real-time information on the present state of network including status of switches or circuit breakers and all available measurements for all network elements which are under that *Network Service Provider's* control and that are included in the *market network model*.
- 3.5.2.2 If there is any material long term change in the status or configuration of a *network* under the control of a *Network Services Provider*, the standing *network data* relevant to that *network* shall be revised by the relevant *Network Service Provider*, and submitted to the *System operator*.
- 3.5.2.3 Each *Network Service Provider* shall submit period-specific *network data* variations to the *System operator* as soon as any material change in previously submitted *network data* becomes apparent with respect to the expected state of any of its *networks* in any *trading or dispatch interval* of any *trading day* in the current *week-ahead market horizon*.



3.5.2.4 The standing *network data* and any variations to that data submitted in accordance with clause 3.5.2.3 shall be provided by *Network Service Providers* in a form which allows the *System operator* to readily derive and verify the information specified in Appendix A2, as it may pertain to any *dispatch interval* of any *trading day* in the *week-ahead market horizon*.

3.5.2.5 Each *Network Service Provider* shall immediately advise the *System Operator* of any circumstances which threaten a significant probability of material adverse change in the state of its *network* in any *dispatch interval* of any *trading day* in the current *week-ahead market horizon*

3.5.3 System operator Data

3.5.3.1 The *System operator* shall submit to the *Market Operator* standing *network data* relating to all *network* elements which are under a *Network Service Provider's* control and included in the *market network model*, in accordance with the *timetable*.

3.5.3.2 Where necessary, the *System operator* shall, in accordance with the *timetable for week ahead, day ahead and hour ahead projections and for real time dispatch*, promptly advise the *Market Operator* to:

- (a) Vary the market network model representation employed for any trading or *dispatch interval* in the current week-ahead market horizon to take account of information received from *Network Service Providers* including the elements that have



armed load shedding schemes and consequently do not need to be operated based on an N-1 security constrained dispatch basis; and

- (b) Apply, or vary, any system security constraints, over-riding constraints or reserve requirements constraints to be applied in any trading or *dispatch interval* in the *current week-ahead market horizon* to take account of current, or projected, system conditions.

3.5.3.3 In determining whether it is reasonably necessary to advise the *Market Operator* under clause 3.5.3.2, the *System operator* shall take into consideration its obligations with respect to maintaining *system security* in accordance with the *WESM Rules*, the *Act*, the *Grid Code* and *Distribution Code*, or any other relevant regulatory instruments.

3.5.3.4 In acting on such advice, the *Market Operator* shall take full account of its obligations to *WESM members* with respect to maintaining the integrity of the market, and the *market network model*, as defined by the *WESM Rules*, the *Act*, or any other applicable regulatory instruments.

3.5.3.5 In accordance with the *timetable*, any revision under clause 3.5.3.2 to the system representation or constraints to be employed with respect to any market *trading or dispatch interval* shall take effect the next time a market dispatch optimization model run is initiated.



- 3.5.3.6 The *System operator* shall advise the *Market Operator* of any circumstances which threaten a significant probability of material adverse change in the state of the *network*, or *system*, in any *trading or dispatch interval* of any *trading day* in the current *week-ahead market horizon*.
- 3.5.3.7 The Market Operator shall publish the market network model representation, all network status data any system security constraints, over-riding constraints or reserve requirements constraints used in any market projections, dispatches and prices and settlements.
- 3.5.3.8 The *System operator* will be responsible for taking measures to ensure that the *Market Operator* is provided with data in a timely and reliable manner, and which has undergone a process of quality checking and (if required and feasible) substitution from alternative primary sources.
- 3.5.3.9 The Market operator and System operator in consultation develop a market procedure to describe data checking and rectification actions for data provision to the Market operator for the following situations: bad quality SCADA data is detected, partial or complete SCADA system failures, failure of market management systems, and the failure of any other IT systems or communication networks that could adversely impact market operations and the measures taken by the Market operator and System operator when they occur.

3.5.4 Load Forecasting



3.5.4.1 Each *Customer* may submit a forecast in respect of each trading or *dispatch interval* for each of its registered load facilities for each trading day of week in accordance with the *timetable*. The forecast submitted by the *Customer* shall be used by the *Market Operator* in the preparation of *Net Load Forecast* if it is within the forecast tolerance range published by the Market Operator.

If the *Customer* fails to submit a forecast of his load facilities in accordance with the timetable or if the Customer forecast submitted is not within the published forecast tolerance range, the forecast prepared by the *Market Operator* at the node where the *Customer* is located shall be used.

Prior to the commencement of the spot market, the *Market Operator*, in consultation with *WESM Participants*, shall determine and publish the forecast tolerance range. The forecast tolerance range may be varied from time to time by the *Market Operator*.

[\(As amended by DOE DC No. 2004-07-008 dated 7 July 2004 and further amended by DOE DC No. 2005-11-010 dated 11 November 2005\)](#)

3.5.4.2 Each *net load forecast* shall be prepared in such a way as to represent the *net load* to be met by *scheduled generation*, including losses occurring outside the system represented by the *market network model*, but excluding any *scheduled load*, and less:

- (a) *Non-scheduled generation*, and
- (b) *Generation from NRE generating units with intermittent energy resource*.



- 3.5.4.3 The unrestrained net load forecast for any *trading or dispatch interval* shall be prepared so as to represent the net load as it would be, or would have been, in the absence of load shedding.
- 3.5.4.4 If load shedding is expected to occur in any *dispatch interval*, a restrained *net load forecast* for that *dispatch interval* shall be prepared on the same basis, but accounting for *load shedding* to the extent that it is expected to occur.
- 3.5.4.5 The Market Operator will annually review the performance of the week ahead, day ahead, hour ahead and dispatch interval nodal demand forecasts.
- 3.5.4.6 The Market Operator will periodically review the methodologies used for week ahead, day ahead, hour ahead and dispatch interval nodal demand forecasts and compare the performance of the WESM forecasts to international benchmarks.

3.5.5 Generation Offers and Data

- 3.5.5.1 Each *Scheduled Generation Company* including *Generation Companies* with *bilateral contracts* shall submit a standing *generation offer* for each of its *scheduled generating units* for each *trading interval* in each *trading day* of the week in accordance with the *timetable*.
- 3.5.5.2 Each *generation offer* shall include the information specified in Appendix A1.1.
- 3.5.5.3 Each *Generating Company* shall, in consultation with the System operator, submit check data to be used by the Market Operator, in accordance with clause 3.5.12, to assist in determining the



validity of any generation offer which may be submitted by the Scheduled Generator.

3.5.5.4 Each Non-Scheduled Generation Company shall submit a standing schedule of loading levels for each of its non-scheduled generating units for each dispatch interval in each trading day of the week in accordance with the timetable.

3.5.5.5 Each *NRE Generation Company* with *intermittent energy resource* shall submit its projected output for each of its *generating units* for each *dispatch interval* in each *trading day* of the week in accordance with the *timetable*.

3.5.6 Customer Demand Bids

3.5.6.1 Each *Customer* may submit a standing *demand bid* in respect of each *dispatch interval* for each of its *registered scheduled load facilities* for each *trading day* of the week in accordance with the *timetable*.

3.5.6.2 Each *demand bid* submitted under clause 3.5.6.1 shall:

- (a) Correspond to load which has been certified as dispatchable, in accordance with the *Grid Code* and *Distribution Code*; and
- (b) Include the information specified in Appendix A1.3.

3.5.6.3 Each *Customer* shall, in consultation with the *System operator*, submit check data for each of its *registered scheduled load facilities* to be used by the *Market Operator* in accordance with clause 3.5.12, to assist in determining the validity of any *demand bid* which it may submit.

3.5.7 Generation Company Reserve Offers



- 3.5.7.1 This section shall apply only upon commencement of the *spot market* for *ancillary services* established under clause 3.3.4.
- 3.5.7.2 When applicable, subject to clause 3.3.4.2, each *Scheduled Generator* registered as an *Ancillary Services Provider* in respect of a *reserve facility* in a particular *reserve region* shall submit a standing *reserve offer* for each of its relevant *reserve facilities* in respect of that *reserve region* for each *trading interval* for each day of the week in accordance with the *timetable*.
- 3.5.7.3 Each *reserve offer* submitted by a *Generation Company* under clause 3.5.7.2 shall:
- (a) Correspond to response capability of the relevant *reserve facility* which has been certified as meeting the relevant reserve response standards, for that *reserve facility category*, in accordance with the *Grid Code and Distribution Code*; and
 - (b) Include the information specified in Appendix A1.2.
- 3.5.7.4 Each *Generation Company* registered as an *Ancillary Services Provider* in respect of a *reserve facility* shall, in consultation with the *System operator*, submit check data to be used by the *Market Operator*, in accordance with clause 3.5.12, to assist in determining the validity of any *reserve offer* which it submits.

3.5.8 Customer Reserve Offers

- 3.5.8.1 This section shall apply only upon commencement of the *spot market* for *ancillary services* established under clause 3.3.4.



- 3.5.8.2 When applicable, subject to clause 3.3.4.2, each Customer registered as an Ancillary Services Provider in respect of a reserve facility in a particular reserve region may submit a standing reserve offer for each of its interruptible load facilities in respect of that reserve region for each trading interval for each day of the week in accordance with the timetable.
- 3.5.8.3 Each reserve offer submitted by a *Customer* under clause 3.5.8.2 shall:
- (a) Correspond to a load for that *Customer* which has been certified as *interruptible* in accordance with the *Grid Code* and *Distribution Code*;
 - (b) Correspond to the response capability of the relevant *reserve facility* registered for the provision of *interruptible load* which has been certified as meeting the relevant reserve response standards for that *reserve facility category* in accordance with the *Grid Code and Distribution Code*; and
 - (c) Include the information specified in Appendix A2.
- 3.5.8.4 Each *Customer* registered as an *Ancillary Services Provider* in respect of a *reserve facility* shall, in consultation with the *System operator*, submit to the *Market Operator* a check data for each of its *reserve facility*, to be used in accordance with clause 3.5.12, to assist in determining the validity of its *reserve offer*.

3.5.9 Revision of Standing Offers/Bids



3.5.9.1 A standing *generation offer*, a standing *reserve offer*, a standing schedule of *loading levels* or a standing *demand bid* for any *trading interval* in any day of the week may be revised by the relevant *Generation Company* or *Customer* in accordance with the *timetable*.

3.5.9.2 A standing *generation offer*, a standing *reserve offer*, or a standing *demand bid* which is revised under clause 3.5.9.1:

- (a) Shall take effect the next time a *week ahead projection* is initiated, in accordance with the *timetable*; and
- (b) Shall only affect the offers employed in *market dispatch optimization model* runs used to determine *projections*, *dispatch*, or *pricing* for periods not already covered by *week-ahead projections* which have already been *published*, or whose preparation has already been initiated at the time when the revised offer or bid is accepted.

3.5.10 Initial setting of Market Offers/Bids

When the *Market Operator* updates a market projection under clause 3.7, the *standing offers* and *standing bids* shall be effective in the absence of revised *market offers* and *market bids* for the corresponding *dispatch interval* and day of the week.

3.5.11 Revision of Market Offers/Bids

3.5.11.1 Each scheduled *Trading Participant* which has submitted *standing offers* or *bids* may revise any of its *market offers* or *market bids* for any *trading interval* in any *trading day* of the current *week-ahead market horizon* in accordance with the



- timetable*, and subject to clause 3.5.11.3 and each revised *market offer* or *market bid* submitted shall provide the information set out in Appendix A2.
- 3.5.11.2 Each *Generation Company* which has submitted a schedule of *loading levels* for its *non-scheduled generating units* shall revise its schedule of *loading levels* if it reasonably expects that any of its anticipated *loading levels* will differ materially from those previously submitted.
- 3.5.11.3 In accordance with the *timetable*, a revised *market offer* or *market bid* submitted under clause 3.5.11.1 shall take effect the next time a *dispatch*, *pricing* or *day-ahead projection* run is initiated.
- 3.5.11.4 *Market bids* or *market offers* for any *trading interval* shall be revised by *Trading Participants* if, at any time, they no longer represent a reasonable estimate of:
- (a) The expected availability of the relevant *generating unit* or *scheduled load* for that *trading interval*; or
 - (b) The *demand bids* or *offers* likely to apply for the real time *dispatch optimization* of that *trading interval*.
- 3.5.11.5 The *Market Operator*, in consultation with the *System operator* and *WESM members*, and with the approval of the *PEM Board*, shall determine and *publish* criteria to determine the meaning of "reasonable estimate" under clause 3.5.11.4, taking account of:
- (a) The time remaining until the occurrence of the relevant *trading interval* involved,



- (b) The impact on the *market* of any variations to offers or *demand bids*,
- (c) The different categories of *WESM members*, and
- (d) The different circumstances which may have given rise to the need to make the relevant variation.

3.5.11.6 *Trading Participants* shall immediately advise the *System operator* and *Market Operator* of any circumstances which threaten a significant probability of material adverse change in the state of their facilities in any *dispatch interval* of any trading day in the current *week-ahead market horizon*.

3.5.11.7 Prior to the spot market commencement date, the *System operator*, in consultation with *WESM members*, shall publish a non-exhaustive list of events that will be deemed to be or to cause a material adverse change in circumstances for the purposes of clause 3.5.11.6.

3.5.11.8 Each market offer *or market bid* for a particular *trading interval* is deemed to stand with effect from the time it is initiated under clause 3.5.10 or revised under clause 3.5.11 and will be used in preparing all *market forecasts*, *dispatch targets* or prices for the corresponding *dispatch intervals*, unless and until a valid revision to the *market offer* is accepted by the *Market Operator*.

3.5.12 Confirmation of Receipt of Valid Offers and Bids

3.5.12.1 To be valid, *generation offers*, *reserve offers* or *demand bids* shall be submitted by the relevant *Trading Participant*:



- (a) In accordance with clause 3.5.1,
- (b) In accordance with the *timetable*; and
- (c) Consistent with the check data submitted by the *Trading Participant* under clauses 3.5.5.3, 3.5.6.3, and 3.5.7.4 as appropriate.

3.5.12.2 The Market Operator shall send to each Trading Participant whom it has received a valid generation offer, reserve offer or valid demand bid, an electronic confirmation of receipt and acceptance of that generation offer, reserve offer or demand bid in accordance with the timetable.

3.5.12.3 If a *Trading Participant* does not receive confirmation of receipt under clause 3.5.12.2, from the *Market Operator* in accordance with the *timetable*, the *Trading Participant* shall contact the *Market Operator* to determine whether or not the *generation offer, reserve offer or demand bid* was received.

3.5.12.4 If the offer or bid is invalid, the *Market Operator* shall promptly inform the *Trading Participant* to resubmit a corrected *generation offer, reserve offered demand bid* in accordance with clause 3.5.11.

3.5.13 Over-riding Constraints

3.5.13.1 Subject to clause 3.5.13.3, the *System operator* may require the *Market Operator* to impose constraints on the power flow, demand, energy generation of a specific facility in the Grid to address system security threat, to mitigate the effects of a system emergency, or to address the need to dispatch generating units to comply with



systems, regulatory and commercial tests requirements. The *System operator* may also relax existing constraints or system requirements on power flows, demand, energy generation and reserves if the *Market Operator* is unable to produce a feasible dispatch schedule.

The *System operator*, in consultation with the *Market Operator* and the *Trading Participants*, shall develop the criteria and procedures for dispatch of generating units that are required to run as a result of the imposition or relaxation of constraints stated in the preceding paragraph, and the manner for compensating said units.

- 3.5.13.2 In situations where offers are structured in such a way that provision of any level of reserve services prohibits the simultaneous provision of very low or high levels of generation, the *System operator* may also recommend to the *Market Operator* that constraints should be imposed or relaxed so as to allow *generating systems* to operate in a range which allows increase of either reserve allocation or energy generation, as appropriate, having regard to:

[\(As amended by DOE DC No. 2006-05-0006 dated 5 May 2006\)](#)

- (a) The commercial interests of *Trading Participants*; and
- (b) Market priorities and objectives, as reflected by the relevant market prices for



energy and reserves in the relevant reserve region.

- 3.5.13.3 Prior to the *spot market* commencement date, the *System operator*, in consultation with *Trading Participants* and the *Market Operator*, shall publish a general description of the nature of circumstances which will cause it to recommend imposition or relaxation of *constraints* under clauses 3.5.13.1 or 3.5.13.2 and the type of action which may be taken under those circumstances.
- 3.5.13.4 When acting under clause 3.5.13.1 or 3.5.13.2, the *System operator* shall:
- (a) Notify the relevant *Trading Participant* of the situation as soon as practicable; and
 - (b) Record appropriate details of the incident.
- 3.5.13.5 At the request of the *Market Operator*, the *System operator* or any *WESM member*, the *market surveillance committee* may review any decision by the *Market Operator* to impose or relax *constraints* under clause 3.5.13.1 or 3.5.13.2.
- 3.5.13.6 If a review conducted under clause 3.5.13.5 concludes that a Trading Participant or the Market Operator or the System operator has acted inappropriately, and has thereby imposed significant costs on other parties, the market surveillance committee may refer that matter to the *Enforcement and Compliance Officer* under clause 7.2 or require that Trading Participant or the Market Operator or the System operator (as the case may be) to pay compensation in accordance with clause 7.2. [\(As amended by DOE DC No. 2006-01-0001 dated 10 January 2006\)](#)



3.6 MARKET DISPATCH OPTIMIZATION MODEL

3.6.1 Model Definition

- 3.6.1.1 The *market dispatch optimization model* simultaneously determines *dispatch* targets for the end of a *dispatch interval*, *reserve* allocations for the *dispatch interval*, associated *energy prices* at all *trading nodes* in the *power system* and when applicable *reserve prices* for all *reserve regions*.
- 3.6.1.2 The *Market Operator* shall maintain and *publish*:
- (a) the formulation of the market dispatch optimization model, in sufficient detail such that an independent person could develop and test the market dispatch optimization model, and
 - (b) the performance standards for the market dispatch and pricing optimization model and processes, in accordance with the *WESM* objectives.
- 3.6.1.3 The objective of the *market dispatch optimization model* shall be to maximize the value of *dispatched load* based on *dispatch bids*, minus:
- (a) The cost of *dispatched generation* based on *dispatched offers*;
 - (b) The cost of *dispatched reserves* based on *reserves* contracted for or when applicable *reserve offers*; and
 - (c) The cost of *constraint violations* based on the *constraint violation coefficients*.
- 3.6.1.4 In formulating the *market dispatch optimization model*, the *Market Operator* and *System operator*



shall ensure that the *dispatch* for each *dispatch interval* is made subject to:

- (a) Constraints representing limits on generation offers, demand bids and when applicable reserve quantities as specified by Trading Participants in accordance with clause 3.5, except to the extent that as they may be relaxed in accordance with clause 3.5.13;
- (b) Constraints representing the technical characteristics of reserve facility categories including joint energy and reserves capacity limits and joint energy and reserves ramping limits;
- (c) Energy balance equations for each node in the market network model ensuring that the net load forecast for the end of the *dispatch interval* at each *market trading node* as determined by the *Market Operator* is met;
- (d) Constraints representing limitations on the ramp rates from the plant statuses or standing data deemed to apply prior to the commencement of the trading interval;
- (e) Constraints defining power system reserve requirements as provided by the System operator under clause 3.5.3 including co-optimized dispatch and contingency reserve requirements;
- (f) Network constraints, as implied by the market network model and any system security constraints provided by the *System operator* under clause 3.5.3;



- (g) Loss and impedance characteristics of market network lines, as advised by the System operator under clause 3.5.3, and defined in Appendix A2;
- (h) Constraints on HVDC link operations, as advised by the System operator under clause 3.5.3, and defined in Appendix A2;
- (i) Power flow equations, as defined by a DC approximation to an AC power flow within AC sub-systems, or equivalent mathematical representation; [\(As amended by DOE DC No. 2006-01-0001 dated 10 January 2006\)](#)
- (j) Any overriding constraints imposed on the recommendation of the System operator in accordance with clause 3.5.13; and
- (k) Any additional constraints due to ancillary services or system security requirements.

3.6.1.5 The *market dispatch optimization model* shall be designed so that, subject to the approximations and adjustments provided for by clause 3.6.4:

- (a) It will produce an *optimal dispatch* given the objective defined by clause 3.6.1.3, and the *constraint* structure defined by clause 3.6.1.4, and specifying *dispatch* targets for each *scheduled generating unit, scheduled load and reserve facility*;
- (b) It will produce a schedule of flows on each transmission line corresponding to the optimal dispatch determined in accordance with clause 3.6.1.5 (a);
- (c) It will produce energy prices for each market trading node, and when applicable



reserve prices for each reserve category and reserve region, so that the recommended dispatch targets for each individual Trading Participant would be optimal for that participant at those prices, given their offers and demand bids and after accounting for other constraints which may affect that Trading Participant, and

- (d) It will perform its functions in accordance with the performance standards approved by the *PEM Board*.

3.6.2 Constraint Violation Variables and Coefficients

3.6.2.1A All key constraints in the *market dispatch optimization model* shall be set up with one or more non negative violations variables and associated constraint violation coefficients to ensure that the *market dispatch model* will always find a solution which satisfies all *constraints*, if such a solution exists;

3.6.2.1B The constraint violation coefficients shall be set for

- (a) market dispatches, and
- (b) market pricing reruns when the market dispatch has resulted in a non zero violation variable.

3.6.2.1C The constraint violation coefficients for market dispatches shall:

- (a) Be set so as to ensure that the *market dispatch model* will always find a solution which satisfies all *constraints*, if such a solution exists; and
- (b) Be set so as to ensure that violated constraints are prioritized, such that the dispatch of network elements, loads and



generating units are physically feasible and reflect the priorities or how the System Operator should manage system security and reliability.

3.6.2.1D The constraint violation variables and constraint violation coefficients for market pricing reruns shall be set so as to ensure that:

- (a) the dispatches of all network elements, loads and generating units produced by the market optimization algorithm are approximately the same as the original market dispatches; and
- (b) the prices produced by the market optimization algorithm will be appropriate in all the circumstances, taking into consideration the processes defined in section **3.6.3B** to adjust or override those prices for projection, dispatch and settlement purposes when there are instances of non zero constraint violation variable values.

3.6.2.2 The *constraint violation coefficients* may:

- (a) Vary according to the time of day, or on any other basis as determined by the Market Operator,
- (b) Increase progressively as the constraint violation becomes more severe; and
- (c) Increase or decrease as a function of the length of time for which the *constraint* has been violated.



- 3.6.2.3 The *constraint violation coefficients* for the nodal *energy balance equations* referred to in clause 3.6.1.4 (c):
- (a) Will be known as the nodal value of lost load (nodal VoLL); and
 - (b) May vary from node to node and/or be set so as to reflect load shedding priorities.
- 3.6.2.4 The *Market Operator*, in coordination with the System Operator, and in consultation with the WESM Members shall regularly review the appropriateness and applicability of constraint violation variables and their associated constraint violation coefficients levels in accordance with clause 10.4.11.1; and revise as maybe necessary to ensure that it reflects the actual conditions of the network. Such revisions shall be approved by the PEM Board and shall be published in accordance with the timetable. **(Added as per DOE DC. No. 2010-03-0004 dated 21 March 2010)**
- 3.6.2.5 For constraints which use two or more violation variables, all violation variables must have upper bounds other than the violation variable corresponding to the highest constraint violation coefficient.

3.6.3 Interpretation of Model Outputs

The output of the *market dispatch optimization model* is to be interpreted as providing *energy* and when applicable *reserve dispatch* targets for the end of each *dispatch interval* to which the *market dispatch optimization model* is applied.

3.6.3B Constraint Violations and Automated Market Dispatch Optimization Model Reruns



- 3.6.2B.1 Should the *market dispatch optimization model* result in one or more non zero constraint violation variable values then the energy targets and reserve quantity outputs shall remain the same but the prices for energy and reserves shall be determined from an automatic rerun of the dispatch optimization with relaxed constraints.
- 3.6.3B.2 The purpose of the automatic market pricing reruns is to ensure that the energy and reserve prices reflect:
- (a) the marginal costs of supplying energy at each node;
 - (b) the marginal costs of supplying regional reserves;
 - (c) shortage pricing when there is a shortage of supply at a node or regional level; and
 - (d) excess pricing when there is an excess of supply at a node or regional level.
- 3.6.3B.3 The automatic rerun of the dispatch optimization shall use the following changes to any of the constraints that had non zero constraint violation variable values:
- (a) For each nodal energy balance constraint that was violated,
 - (i) For a violation amount of X, the nodal demand shall be reduced by an amount slightly smaller than the corresponding violation variable's value (X-delta where "delta" is a small value);
 - (ii) The constraint shall use an additional violation variable corresponding to with an upper limit of 2 x delta; and



- (ii) the constraint violation coefficient for the new violation variable shall be set to the minimum of the node's nodal VoLL and the market price cap; and
- (b) For all other constraints that were violated, each constraint's requirement shall be reduced by the minimum amount to a level that prevents a violation of that requirement.

3.6.3B.4 The automated rerun shall solve the *market dispatch optimization model* with the reduced *nodal* energy and other violated constraint's requirements.

3.6.3B.5 The prices determined from the automated rerun shall be the prices used for forecasts, dispatches and settlements.

3.6.3B.6 The automated rerun process of detecting non zero constraint violation variable values, setting up the relaxed dispatch optimization and solving it shall occur as quickly as possible and take no longer than one minute or the time nominated in Market Operator's published performance standards for the market dispatch and pricing optimization model and processes as required in 3.6.1.2 (b).

3.6.4 Modeling Approximations

3.6.4.1 If the *Market Operator* deems it to be appropriate in all the circumstances, the *market dispatch optimization model* may incorporate reasonable approximations so as to render the optimization problem solvable using an established *optimization methodology* such as linear programming.

3.6.4.2 Any approximations introduced in accordance with clause 3.6.4.1:



- (a) May involve producing a piece-wise linear approximation to a non-linear function;
- (b) May involve producing a convex approximation to a non-convex function;
- (c) May include automated procedures to deal with situations in which a choice shall be made to impose or relax certain *constraints*, as provided for in clause 3.5.13; and
- (d) Shall preserve, under all operating conditions, an accuracy which is generally acceptable to all *WESM members* and particularly to any *Trading Participants* directly affected by such approximations.

3.6.5 Model Development

3.6.5A Model Audit

Prior to implementing any material changes in the Market Dispatch Optimization Model and associated processes in the WESM, the model formulation and software shall be independently audited to determine whether the changes are compliant with the WESM Rules.

3.6.5 Model Development

From time to time, the *System operator* and the *Market Operator* shall investigate the scope for further development of the *market dispatch optimization model* beyond the minimum requirements specified in clause 3.6.1 and, submit their recommendations in a report to the *PEM Board* for consultation with *WESM members*.

[\(As amended by DOE DC No.2005-11-010 dated 11 November 2005\)](#)

3.6.6 Market Settlement

The market shall be cleared, prices determined, and dispatch determined according to the model results for each *dispatch*



interval, in the form that is written. The model results shall not be challenged ex-post.

In the event that *Trading Participants* identify solution inconsistencies with the stated definition and objectives of the model, the *Market Operator* will formulate a plan to correct the model.

Notwithstanding such model solution errors, the *spot market* shall continue to be cleared according to the model results until a model revision is put into service in accordance with clause 3.6.5.

3.7 MARKET PROJECTIONS

The *Market Operator* shall prepare and *publish week ahead projections* and *day ahead projections* using the *market dispatch optimization model*, in accordance with the *timetable*.

3.7.1 Week Ahead Projections

3.7.1.1 *Week ahead projections* shall be prepared by the *Market Operator* and *published* daily, in accordance with the *timetable*, to assist *Trading Participants* to anticipate and respond to the range of *spot market* conditions which might reasonably be expected to occur over the forthcoming week.

3.7.1.2 *Week ahead projections* shall be prepared for all *trading intervals* within the relevant *market horizon* as defined in the *timetable*.

3.7.1.3 *Week ahead projections* will be based on the *market dispatch optimization model* defined in section 3.6 based on input data prepared by the *Market operator* over the appropriate time horizon in accordance with clause 3.7.3.

3.7.2 Day Ahead Projections



- 3.7.2.1 *Day ahead projections* shall be prepared using the *market dispatch optimization model* by the *Market Operator* and *published* regularly through the day, in accordance with the *timetable*, to assist *Trading Participants* to anticipate and respond to the range of *spot market* conditions which might reasonably be expected to occur over the forthcoming day.
- 3.7.2.2 *Day ahead projections* shall be prepared for all *trading intervals* within the relevant *market horizon* as defined in the *timetable*.
- 3.7.2.3 *Day ahead projections* will be determined by running the *market dispatch optimization model* defined in section 3.6 with input data prepared by the *Market operator* over the appropriate time horizon in accordance with clause 3.7.3.

3.7.2A Hour Ahead Projections

- 3.7.2A.1 *Hour ahead projections* shall be prepared using the *market dispatch optimization model* by the *Market Operator* and *published* at every dispatch interval, in accordance with the *timetable*, to assist *Trading Participants* to anticipate and respond to *spot market* conditions which might reasonably be expected to occur over the next hour.
- 3.7.2A.2 *Hour ahead projections* shall be prepared for all *dispatch intervals* within the relevant *market horizon* as defined in the *timetable*.
- 3.7.2A.3 *Hour ahead projections* will be determined by running the *market dispatch optimization model* defined in section 3.6 with input data prepared by



the Market operator over the appropriate time horizon in accordance with clause 3.7.3.

3.7.3 Preparation of Market Projections

3.7.3.1 Each *market projection* shall take into consideration:

- (a) The *network service provider data* prepared in accordance with clause 3.5.2;
- (b) *Reserve requirements*, the anticipated *market network model configuration*, *constraints* and *system security* requirements for each *reserve region*, as advised by the *System operator* in accordance with clause 3.5.3;
- (c) The forecast demand information prepared in accordance with clause 3.5.4;
- (d) The *generation offer* information submitted by each relevant *Trading Participant* in accordance with clause 3.5.5;
- (e) The *loading levels* for each non-scheduled and *NRE generating units* with *intermittent energy resource* in accordance with clause 3.5.5; and
- (f) When applicable, the *reserve offer* information submitted by each relevant *Trading Participant* in accordance with clause 3.5.7 and 3.5.8.

3.7.3.2 Prior to the preparation of each set of *market projections*, the *Market Operator* shall, in consultation with the *System operator*, prepare an expected unrestrained net *load forecast* in accordance with the procedures developed under clause 3.5.4, and such number of other load *scenarios* as may be determined in consultation with *WESM Participants* and approved by the *PEM Board*.



- 3.7.3.3 The Market Operator shall prepare a market projection corresponding to each load scenario developed under clause 3.7.3.2.
- 3.7.3.4 When a probability of a significant failure in the power system has been advised to the System operator, the Market Operator may, in consultation with the System Operator, also prepare market projections in which the constraint structure is modified to represent a situation in which such failures occur.
- 3.7.3.5 Market projections shall be prepared by the Market Operator through the application of the market dispatch optimization model to all trading intervals within the relevant market horizon as defined in the timetable.
- 3.7.3.6 When preparing *week ahead market projections* and *day ahead market projections*, the starting conditions for each successive *trading interval* shall be determined:
- (a) In respect of the first *trading interval*, as the actual, or expected, *power system* conditions at the time of the commencement of the *market projection*; and
 - (b) In respect of subsequent *trading intervals*, as the projected *power system* conditions determined by the *market dispatch optimization model* for the end of the previous *trading interval* in that *market projection*.



- 3.7.3.6A When preparing *hour ahead market projections*, the starting conditions for each successive *dispatch interval* shall be determined:
- (a) In respect of the first *dispatch interval*, as the projected power system conditions determined by the *market dispatch optimization model* that was used to determine targets for the end of the current *dispatch interval*;
 - (b) In respect of subsequent *dispatch intervals*, as the projected power system conditions determined by the *market dispatch optimization model* for the end of the previous *dispatch interval* executed as part of the *hour ahead market projection*.
- 3.7.3.7 The Market Operator shall publish additional updated versions of a market projection in the event of changes which, in the opinion of the Market Operator, are material and which should be communicated to Trading Participants.
- 3.7.3.8 The *Market Operator* shall document the exact procedure it uses for preparation of *market projections* and make the procedure available to all *Trading Participants*.

3.7.4 Published Information

- 3.7.4.1 Based on the information referred to in clause 3.7.3, each *market projection published* by the *Market Operator* in accordance with the *timetable* shall contain the following information for each *week ahead trading interval*, *day ahead trading interval* and *hour ahead dispatch interval* in the period covered by the *market projection*:



- (a) The assumed *net load forecast* at each *market network node*, plus required reserves for each *reserve region*;
- (b) The required level of *reserve* for each *reserve region*;
- (c) Any modifications to *plant or network* availability which the *Market Operator* may have made under clause 3.5.13 in forming this projection;
- (d) Projected aggregate *dispatch* of scheduled *generating units* and *scheduled load* at each *market network node*;
- (e) Projected aggregate cleared *reserve quantities* for reserve regions and *reserve facility categories*;
- (f) The projected *market price* for each *market trading node*;
- (g) When applicable *projected reserve prices* for each *reserve region*; and
- (h) Identification and quantification of:
 - (1) Projected *load shedding* requirement;
 - (2) Projected *violations of system security*;
 - (3) Projected failure to meet *reserve* requirements;
 - (4) *Trading intervals* or *dispatch intervals* for which low or inadequate capacity margins are projected to apply; and
 - (5) Projected congestion on *market network lines*; and



- (6) Non zero constraint violation variables and their associated *constraint violation coefficients*.

3.8 SCHEDULING AND DISPATCH IMPLEMENTATION

3.8.1 Responsibilities of the Market Operator

Prior to commencement of each *dispatch interval*, the *Market Operator* shall, in consultation with the *System Operator*, and in accordance with the *timetable*:

(As amended by DOE DC No.2003-11-010 dated 11 November 2005)

- (a) Determine, or estimate, the status of all generation facility for that *dispatch interval*;
- (b) Prepare a forecast of the *unrestrained net load* expected at each *market trading node* for the end of that *dispatch interval*;

(As amended by DOE DC No.2005-11-010 dated 11 November 2005)

- (c) Adjust that *unrestrained net load forecast* to account for *load shedding*, if required, in accordance with clause 3.9.5;
- (d) Determine the most appropriate network configuration and state to be assumed for the end of that *dispatch interval*;
- (e) Use the *market dispatch optimization model* to determine the *target loading level* in MW for each *scheduled generating unit* or *scheduled load* and for each *reserve facility* for the end of that *dispatch interval* using the latest data from the *System operator* and *Trading Participants*; and
- (f) Submit to the *System operator* the *dispatch schedule* containing the target *loading levels* to be achieved at the



end of that *dispatch interval*, determined in accordance with clause 3.8.1 (e).

3.8.2 Responsibilities of the System operator

3.8.2.1 During each *dispatch interval*, the *System operator* shall use its reasonable endeavors to:

- (a) Implement the *dispatch* targets determined by the *Market Operator*,
- (b) Maintain *system security* consistent with the requirements of the *Grid Code*;
- (c) Implement *load shedding*, if necessary, as provided by clause 3.9; and
- (d) Intervene, where necessary, as provided by clauses 6.3 and 6.5.

3.8.2.2 After each *dispatch interval*, in accordance with the *timetable*, the *System operator* shall advise the *Market Operator* of:

- (a) Situations in which it became necessary for dispatch instructions to deviate from the dispatch targets determined by the Market Operator during the *dispatch interval*;
- (b) *Load shedding* or other directions issued by the *System operator* during the *dispatch interval*;

[\(As amended by DOE DC No.2005-11-010 dated 11 November 2005\)](#)

- (c) Significant incidents in which *contingency reserve* was called upon during the *dispatch interval*;
- (d) *Network constraints* which affected *dispatch* during the *dispatch interval*;
- (e) Binding security constraints which affected dispatch during the dispatch interval; and



- (f) Operational irregularities arising during the dispatch interval including but not limited to any circumstances in which there was prima facie evidence of a failure to follow dispatch instructions.

3.8.3 Communication of target loading levels

The *System operator* shall communicate the target *loading levels* to *Trading Participants* for each *dispatch interval* prior to the commencement of that *dispatch interval* in accordance with the *timetable* and consistent with the *Grid Code*.

3.8.4 Dispatched Trading Participants

Trading Participants who are *dispatched* shall use reasonable endeavors to achieve a *linear ramp rate* over the *dispatch interval* reach the target *loading level* by the end of that *dispatch interval* and within the *dispatch conformance standards* specified in clause 3.8.7 and those *Trading Participants* will not be required to operate in any different fashion unless required to:

- (a) Respond in accordance with *reserve or ancillary service* contracts; or
- (b) Respond to a direction in accordance with clauses 6.3 and 6.5.

3.8.5 Ramp Rate of Trading Participant

Where applicable, *Trading Participants* will be assumed to have a *linear ramp rate* over that *dispatch interval* to reach the target *loading levels* by the end of that *dispatch interval*.

3.8.6 Deviations from the Ramp Rate

If *Trading Participants* in some part of the *power system* deviate in aggregate from the assumed *linear ramp rate* for any reason or as a result of any cause including the initiation of *load shedding* under clause 3.9.3, these deviations shall be dealt with



by the *System operator*, utilizing the *reserves*, or other *ancillary services* scheduled to deal with such circumstances, in accordance with clause 3.3.

3.8.7 Dispatch Conformance

- 3.8.7.1 The *Market Operator* shall develop, publish and maintain *dispatch conformance standards* in consultation with the *System operator*;
- 3.8.7.2 The *dispatch conformance standards* shall define the methodology that the *System operator* will use to determine whether any centrally dispatched facility (generator or load) is not conforming to dispatch instructions, ancillary services and detail the procedures the *System operator* and *Market Operator* will follow in the event that a facility has been identified to be non-conforming;
- 3.8.7.3 The *System operator* will implement a system to automatically check for non-conformance;
- 3.8.7.4 Any centrally dispatched facility that fails to respond to dispatch instructions within a prescribed accuracy and duration (as assessed over consecutive dispatch intervals), that are defined in the *dispatch conformance standards* will be declared to be non-conforming to dispatch instructions;
- 3.8.7.5 The *dispatch conformance standards* for assessing whether a facility is non-conforming to dispatch instructions will take into account any ancillary service quantities, ancillary service responses and/or the minimum stable level applicable to a given facility;
- 3.8.7.6 If a facility is declared to be non-conforming to dispatch instructions by the *System operator* then:



- (a) the System operator will immediately notify the Trading Participant responsible for that facility's operations and request the reason for the non-conformance;
- (b) if in the System Operator's reasonable opinion the facility's technical parameters need to be modified to ensure a realistic dispatch, these will be requested from the Trading Participant;
- (c) if the Trading Participant does not respond in a timely manner to 3.8.7.7 (a) and 3.8.7.7 (b), then the System operator will be allowed to exercise its discretion and will adjust the facility's technical parameters or use constraints to ensure the facility will be provided with a realistic dispatch target in the next dispatch interval;
- (d) the System operator will advise the Market operator as soon as possible of any facilities that have been found to be non-conforming and will advise the corrective measures to be taken, including any adjustments to the facility's technical parameters or additional constraints to be included in the next dispatch interval;
- (e) a facility will continue to be assessed as a non-conforming facility until such a time as the Trading Participant of that facility can satisfy the System operator that the cause of the non-conformance has been rectified. After which, the facility will no longer be declared to be non-conforming.

3.8.7.7 The conformance standard will also detail the approach that the System operator will take in order to determine whether any facilities that have



non-zero ancillary service quantities provided responses consistent with those required by the Grid Code following the occurrence of a power system event that required the deployment of those ancillary services.

- 3.8.7.8 If a facility is declared to be non-conforming to ancillary services by the System operator then:
- (a) the System operator will immediately notify the Trading Participant responsible for that facility's operations and request the reason for the non-conformance;
 - (b) if in the System Operator's reasonable opinion the facility's technical parameters for ancillary services need to be adjusted to avoid future non-conformance, these will be requested from the Trading Participant;
 - (c) if the Trading Participant does not respond in a timely or satisfactory manner to 3.8.7.8 (a) and 3.8.7.8 (b), then the System operator will be allowed to exercise its discretion and will adjust the facility's technical parameters for ancillary services to ensure the facility will be provided with realistic ancillary service quantities in the next dispatch interval;
 - (d) In situations where the System operator finds that an ancillary service provider was highly non-conformant then the System operator has the right to suspend that participant from providing those ancillary services;
 - (e) the System operator will advise the Market operator as soon as possible of any facilities that have been found to be non-conforming for ancillary



services and will advise the corrective measures that are to be taken, including any adjustments to the facility's technical parameters for ancillary services;

(f) a facility will continue to be assessed as a non-conforming facility for ancillary services until such a time as the Trading Participant of that facility can demonstrate to the System operator that the cause of the non-conformance has been rectified; and

(g) Trading participants that operate facilities found to be non-conforming for ancillary service can be fined a portion of their revenue earned for ancillary services since they were last confirmed to be a conforming ancillary services provider.

3.8.7.9 The *Market Operator* will in consultation with the System operator periodically review the application of, and the appropriateness of the dispatch conformance standard, with a view to enhancing it over time.

3.8.8 Sanctions of Trading Participants

Any *Trading Participant* who consistently fails to use its reasonable endeavors to act in accordance with *dispatch* instructions issued under clause 3.8.3, or who breaches the *dispatch tolerance* standards *published* under clause 3.8.7.2, may be liable of a sanction imposed under clause 7.2.

3.9 TREATMENT OF LOAD SHEDDING, EXCESS GENERATION AND RESERVE VIOLATION

[\(As amended by DOE DC No. 2006-01-0001 dated 10 January 2006\)](#)



3.9.1 Direction to Conduct Load Shedding

The *System operator* may direct a *Trading Participant* to conduct *load shedding* in response to:

- (a) An overall shortage of *energy* at a *node* or in a region specified in the *market network model*; or
- (b) Other *network conditions*, as determined by the *System operators* accordance with the procedures established under the *Grid Code and Distribution Code*.

3.9.2 Market Operator Advice on Load Shedding

In the event that:

- (a) *Day ahead projections* performed under clause 3.7; or
- (b) *Dispatch optimization* performed under clause 3.8, indicates that nodal loads are expected to be shed by the presence of non zero nodal energy constraint violations variables or *energy prices* which are expected to be equal to, or exceed, nodal VoLL at any *customer nodes* in the *market network model*, then the *Market Operator* shall immediately inform the *System operator* of the likelihood of initiating *load shedding* at those nodes.

3.9.3 System operator Responsibility to Initiate Load Shedding

The *System Operator*.

- (a) Shall, if advised by the *Market Operator* under clause 3.9.2, consider the need to initiate *load shedding*, at those nodes, or at other nodes, after taking account of the *load shedding* targets from the relevant *dispatch optimization*, and any other considerations which the *System operator* considers relevant under the *Grid Code and Distribution Code* and any other applicable regulatory instrument; and
- (b) May initiate *load shedding* in response to any other circumstances which it reasonably considers necessitates



such action under the *Grid Code and Distribution Code* or any other applicable regulatory instrument.

3.9.4 Advising of Load Shedding

If it is anticipated that *load shedding* will occur in a *dispatch interval*, the *System operator* shall, as soon as possible, advise its load shedding plans to:

- (a) The *Market Operator*; and
- (b) *Trading Participants* who are likely to be directly affected by such *load shedding*.

3.9.5 Revising Forecasts

If advised by the *System operator* of the likelihood of *load shedding* in any *dispatch interval* under clause 3.9.4, the *Market Operator* shall, as soon as possible:

- (a) If practical within the time frame remaining before the start of that *dispatch interval*, revise the *load forecasts* to be used to determine the *dispatch schedule* for that *dispatch interval* in accordance with clause 3.5.4.4, to account for those *load shedding plans*; and
- (b) Issue additional *day ahead projections*, if required, under clause 3.7.3.7.

3.9.6 Pricing Error Notice

If, as a result of *load shedding*, no *prices* can be determined or communicated within the timeframe specified in the timetable, or the calculated *prices* are believed to be in error, the *Market Operator* shall, as soon as possible, issue a *pricing error notice* in accordance with clause 3.10.5. [\(As amended by DOE DC No. 2005-11-010 dated 11 November 2005\)](#)

3.9.7 Management of Load Shedding

The *System operator* and the *Market Operator* shall manage all aspects of *dispatch* and *pricing* during periods when *load shedding* is required in accordance with the detailed procedures



to be developed by the *System operator* and the *Market Operator*, in consultation with *WESM Participants*, and subject to approval by the *PEM Board*, consistent with the *Grid Code and Distribution Code*

3.9.8 Management Procedures for Excess Generation

- 3.9.8.1 Should either the *dispatch optimization*, or any *market projection*, indicate *excess generation* at any *node*, the *Market Operator* shall advise the *System operator* that it may be necessary to require some *generating systems* to shut down.
- 3.9.8.2 Where necessary to shut down *generating systems* under clause 3.9.8.1, the *System operator* and the *Market Operator* shall manage all aspects of *dispatch* and pricing in accordance with the procedures to be developed by the *System operator* and the *Market Operator*, in consultation with *WESM Participants*, and subject to approval by the *PEM Board*.

3.9.9 Management Procedures for Reserve Violation

(Added as per DOE DC No. 2006-01-0001 dated 10 January 2006)

- 3.9.9.1 Should either the *dispatch optimization* or any *market projection* indicate a violation of a reserve requirement, the *Market Operator* shall: **(Added as per DOE DC No. 2006-01-0001 dated 10 January 2006)**
- (a) Promptly advise the *System operator* that it may be necessary to reduce the level of the reserve requirement.
 - (b) Reduce the *reserve* requirement by the minimum amount to a level that prevents a violation of that requirement.



3.10 DETERMINATION OF MARKET PRICES

3.10.1 Calculation of Nodal Dispatch Prices

For each *dispatch interval*, the *Market Operator* shall calculate, and publish in accordance with the *timetable*:

- (a) *nodal energy prices* in accordance with clause 3.10.2;
- (b) *zonal energy prices* in accordance with clause 3.10.3; and
- (e) When applicable, *zonal reserve prices* in accordance with clause 3.10.10.

3.10.1A Market Price Cap and Market Price Floor

- (a) The nodal energy market price cap is a price cap that is to be applied to nodal dispatch prices;
- (b) The value of the nodal energy market price cap prior to 1 January 2015 shall be determined by the Market Operator and approved by ERC. Effective on and from 1 January 2015, the value of the nodal energy market price cap for each year shall be determined by the Market Operator and approved by ERC and be published on or before 1 July the year prior to its application;
- (c) The nodal energy market price floor is a price floor which is to be applied to nodal dispatch prices; and
- (d) The value of the nodal energy market price floor prior to 1 January 2015 shall be determined by the Market Operator and approved by ERC. Effective on and from 1 January 2015, the value of the nodal energy market price floor for each year shall be determined by the Market Operator and approved by ERC and be published on or before 1 July the year prior to its application.
- (e) When determining the nodal price cap, the Market Operator shall consider the spot prices required for a marginal peaking generator to break even and cover its



fixed and variable costs and for the WESM to satisfy its reliability targets.

3.10.2 Determination of Nodal Energy Dispatch Price

The *nodal energy price* for each *market trading node* in any *dispatch interval* shall, subject to clause 3.10.5, be determined as the ex-ante *shadow price* on the *energy balance equation* or equivalent mathematical formulation for that *market trading node* formed in accordance with clause 3.6.1.4 (c), in the *market dispatch optimization* performed for that *dispatch interval* in accordance with clause 3.8.1. [\(As amended by DOE DC No. 2006-01-0001 dated 10 January 2006\)](#)

3.10.3 Determination of Zonal Energy Dispatch Prices

Zonal energy prices shall be determined for each *customer pricing zone*.

3.10.4 Publishing Dispatch Prices According to Timetable

The *Market Operator* shall *publish* the *nodal energy dispatch prices* and the *zonal energy prices*, prior to the commencement of the *dispatch interval* to which they apply in accordance with the *timetable*.

3.10.5 Pricing Error Notice

In the event where no *dispatch prices* can be determined or communicated within the timeframe specified by the *timetable*, or the calculated prices are believed to be in error, as a result of *load shedding* or for any other reason: [\(As amended by DOE DC 2005-11-010 dated 11 November 2005\)](#)

- (a) The *Market Operator* may, as soon as possible after the end of a *dispatch interval*, issue a *pricing error notice* and the *Market Operator* shall implement a manual re-run the *Market Dispatch Optimization Model* with *appropriately revised inputs*.



- (b) The *Market Operator* shall develop and publish the procedures for the determination of the manual market re-run prices. Such procedures shall provide the criteria and conditions for the manual market re-runs and the timetable for implementation. The procedures developed for the manual market re-runs shall be designed to produce prices reflecting supply shortages at any nodes where there was load shedding and prices reflecting supply excess where there was excess generation.
- (b)

3.10.9 Determination of Energy Settlement Prices

Subject to clause 3.10.5, the *energy settlement prices* for each *market trading node* in each *trading interval* shall be determined as:

- (a) The load-weighted sum of the *zonal energy dispatch prices* for the set of *dispatch intervals* corresponding to that *trading interval* determined for that *customer pricing zone* in accordance with clauses 3.10.3, if that node is deemed to be a *customer node* and to lie in a defined *customer pricing zone*; and
- (b) The generation-weighted sum of the *nodal energy dispatch prices* for the set of *dispatch intervals* corresponding to that *trading interval* for that node, determined in accordance with clauses 3.10.2, respectively, for all other nodes.

3.10.10 Determination of Regional Reserve Dispatch Prices

- (a) When applicable, the *regional reserve dispatch price* for each *market reserve region* and reserve category in each *dispatch interval* shall be determined as the *shadow price* on the relevant *reserve requirement constraint*, defined in accordance with clause 3.6.1.4 (e), in the *dispatch*



optimization for that dispatch interval and published by the Market Operator before the start of that dispatch interval.

- (b) When applicable, the *regional reserve trading price* for each market reserve region and reserve category in each *trading interval* shall be determined as the weighted average of the corresponding dispatch interval regional reserve prices for that reserve category.

3.11 MARKET INFORMATION

3.11.1 Market Information

- 3.11.1.1 The *Market Operator* shall *publish* the following:
 - (a) *Nodal energy dispatch prices* for all *dispatch intervals* and for each *market trading node*;
 - (a1) *Energy settlement prices* for all *trading intervals* and for each *market trading node*;
 - (b) *Zonal energy dispatch prices* for all *dispatch intervals* and for each *customer energy pricing zone*;
 - (b1) *Zonal energy settlement prices* for all *trading intervals* and for each *customer energy pricing zone*;
 - (c) When applicable, *reserve dispatch prices* and requirements for each *reserve region* and *reserve service*;
 - (d) Binding *network constraints*, for each *dispatch interval* in accordance with the *timetable*;
 - (e) Violated network and other constraints and the corresponding non zero constraint violation variable values;
 - (f) The status of all elements of the market network model such as network element



outages, network switch and circuit breaker statuses; and

- (f) After the trading day:
 - (1) all information necessary to recreate or independently verify the market projections, dispatches and prices, and
 - (2) for a market participant the specific information that would enable the participant to recreate or independently verify its settlements.

3.11.1.2 As part of the information record under clause 5.2.5, the

Market Operator shall retain details of:

- (a) Final *dispatch* offers and when applicable, *reserve* offers;

[\(As amended by DOE DC No.2005-11-010 dated 11 November 2005\)](#)

- (b) Final *dispatch* bids; and
- (c) Actual availabilities of generating units and scheduled load,
- (d) Including, for each *dispatch interval* and dispatch offer and dispatch bid:
- (e) The identification of the *Trading Participant* submitting the *dispatch* bid or *dispatch* offer

[\(As amended by DOE DC No.2005-11-010 dated 11 November 2005\)](#)

- (f) The *dispatch* bid or *dispatch* offer prices and quantities; and
- (g) The time at which any final *dispatch* offer or *dispatch* bid was made.



3.11.1.3 Each *trading day*, in accordance with the *timetable*, the

Market Operator shall *publish*:

- (a) The *scheduled generation* or *scheduled load* and *scheduled reserves* for each *scheduled generating unit* and *scheduled load*, respectively, in each *trading interval* for the previous *trading day*; and
- (b) A summary of the information provided to it with respect to each *dispatch interval* by the *System operator* in accordance with clause 3.8.2.2.

3.11.2 Access to Information

3.11.2.1 All information relating to the operation of the *spot market* that the *Market Operator* is required to *publish* in accordance with the *WESM Rules* shall be made available by the *Market Operator* via the *electronic communications system*.

3.11.2.2 If the *Market Operator* makes information available under clause 3.11.2.1 by additional means other than the *electronic communications system*, the *Market Operator* may, at its discretion, charge a fee for access to that information provided that such fee reflects the *Market Operator's* costs of providing that information.

3.11.2.1 All information available to all market participants shall be deemed to be publicly available information.

3.12 FINANCIAL TRANSMISSION RIGHTS



3.12.1 Market for Transmission Rights

When necessary or reasonably feasible, the *Market Operator* shall establish a market for *transmission rights* as approved by the *PEM Board*.

3.12.2 Publication of Rental Information

The *Market Operator* shall regularly *publish* in summary form the rentals associated with each *market network line* as calculated under clause 3.13.12.

3.12.3 Further Transmission Rights

From time to time, and at least annually, the *Market Operator* shall assess the potential for the issuance of further *transmission rights*, of the form provided for in the *settlements* process defined by clause 3.13.

3.12.4 Matters to Consider in Assessment

The assessment shall take account of the:

- (a) Demand for *transmission rights* between particular locations, as evidenced by *WESM member* submissions;
- (b) Uncommitted physical capacity between those locations, as indicated by the difference between the physical capacity of the lines involved, and the *transmission rights* already issued; and
- (c) Economic feasibility of supporting further *transmission rights*, as indicated by the difference between the line rental trading amounts calculated for particular lines in accordance with clause 3.13.12, and the cost of supporting *transmission rights* already issued, as evidenced by the *transmission rights* trading amounts calculated in accordance with clause 3.13.13.

3.12.5 Issuing Transmission Rights

- 3.12.5.1 *Transmission rights* may be issued by the *Market Operator*, and may be settled via the *settlements*



system, in accordance with clause 3.13.15, provided:

- (a) The issuer of the *transmission right* enters into a commitment to support that *transmission right*, in accordance with clause 3.13.2 (d);
- (b) The issuer of the *transmission right* complies with such *prudential requirements* as may be approved by the *PEM Board* under clause 3.14 taking into account the implied potential exposure of the issuer to *settlement price* differences between the *nodes* involved;
- (c) The *transmission right* is defined between two *markets trading nodes*; and
- (d) The relevant details of the *transmission rights* are notified to the *Market Operator*, in accordance with clause 3.13.2.

3.12.5.2 A *WESM member* may request the *Market Operator* to make available a *transmission right* at an appropriate price.

3.12.5.3 The issuance of a *transmission right* is not to be unreasonably withheld.

3.12.6 Accounting for Net Income

The net income that will be derived by the *Market Operator* from the transactions required under clause 3.13.16 or from the sale of *transmission rights*, shall be clearly accounted for, and taken into account when setting the allowable charges under any regulatory instruments applicable to the *Market Operator*.

3.13 SETTLEMENT QUANTITIES AND AMOUNTS

3.13.1 Submission of Bilateral Contract Data



3.13.1.1 *Trading Participants* who sell electricity pursuant to *bilateral contracts* and wish those *bilateral contracts* to be accounted for in settlements shall, after each *trading day*, in accordance with the billing and settlements timetable: [\(As amended by DOE DC No. 2005-11-010 dated 11 November 2005\)](#)

- (a) Submit a schedule to the *Market Operator* specifying the
MWH *bilateral sell quantities* at each *relevant market trading node*, in each *trading interval* of that *trading day*;
- (b) Identify the counterparty to the bilateral contract and the party that will pay the line rental trading amount associated with the bilateral contract quantity submitted; provided, however, that in case only one of the bilateral counter parties is registered as a *Direct WESM Member*, that *WESM Member* shall be the party that will pay the line rental to the *Market Operator*; and [\(As amended by DOE DC No. 2004-07-008 dated 7 July 2004 and further amended by DOE DC No. 2006-11-0013 dated 09 November 2006\)](#)
- (c) Provide evidence that the counterparty to the *bilateral contract* agrees with the submission made under this clause 3.13.1.1. Such evidence shall be attached to the submission of schedule in 3.13.1.1(a). [\(As amended by DOE DC No. 2010-03-0004 dated 21 March 2010\)](#)



- 3.13.1.2 *Bilateral sell quantities* submitted in accordance with clause 3.13.1.1 (a) are to be deemed to be *bilateral buy quantities* for the party identified in clause 3.13.1.1 (b), at the same *market trading node*.

3.13.2 Submission of Transmission Right Data

- 3.13.2.1 This section shall apply only upon commencement of the *transmission rights* market established under clause 3.12.1.

- 3.13.2.2 *Trading Participants* who hold *transmission rights* and wish to have those *transmission rights* accounted for in *settlements* shall, after each *trading day*, in accordance with the *timetable*, submit to the *Market Operator* a schedule specifying:

- (a) The *sending node* and *receiving node* between which each *transmission right* applies;
- (b) The MWH quantities of each *transmission right* in each *trading interval* of that *trading day*, as they apply at the *sending node*;
- (c) The agreed loss differential associated with each *transmission right*, if any, as a proportion of the quantity specified in clause 3.13.2 (b); and
- (d) That the *System operator* is in agreement with the submission made under clause 3.13.2 (and providing evidence of that agreement), and will cover any deficit in that *System operator's* settlements position with the *spot market* under clause



3.13.15.1(b) arising as a result of honoring this *transmission right*.

3.13.3 Data for Bilateral Contracts and Transmission Rights

The *Market Operator* shall:

- (a) Inform the *Trading Participants* which submitted data under clause 3.13, if any of the data provided is invalid or incomplete; and
- (b) If the data provided under clause 3.13 is valid or complete, employ that data for settlements purposes in accordance with clauses 3.13.7 and 3.13.13.

3.13.4 Zonal Reserve Settlement Quantity

The *zonal reserve settlement quantity* for each *Trading Participant* in each *dispatch interval* shall be calculated as:

- (a) The aggregate, across all of the *Trading Participant's* facilities in the relevant *reserve region*, of the *reserve target* determined by the *dispatch optimization* performed prior to the beginning of that *dispatch interval*, in accordance with clause 3.8.1.

3.13.6 Defining the Gross Energy Settlement Quantity for Market Trading Nodes

For each *trading interval*, the *gross energy settlement quantity* before being adjusted for bilateral contracts for each *market trading node* shall be determined by the *Market Operator* as follows:

- (a) If the *market trading node* is defined under clause 3.2.2.1 as lying on the boundary of the *power system* operated by the *System Operator*, the *gross energy settlement quantity* for the *market trading node* is the net metered flow into the *power system* operated by the *System operator* through the associated meter, provided however, that if the *market trading node* is a *customer*



node, and there is no ERC-registered embedded generation facility associated with that node, or the source of injection cannot be traced, any injection shall not be accounted for in determining the gross *energy settlement quantity* for that node; [\(As amended by DOE DC No. 2005-11-010 dated 11 November 2005 and further amended by DOE Circular No. DC 2013-07-0017 dated 26 July 2013\)](#)

- (b) If the *market trading node* is defined under clause 3.2.2.2 as a *generator node* lying on the interface between networks, apparatus or equipment operated by parties other than the *System Operator* the gross *energy settlement quantity* for the *market trading node* is the net metered flows through the associated meter from the *Generation Company* to the *Customer* side of the meter; and [\(As amended by DOE DC No. 2005-11-010 dated 11 November 2005\)](#)
- (c) If the *market trading node* is defined under clause 3.2.2.2 as a customer node lying on the interface between networks, apparatus or equipment operated by parties other than the *System operator* the gross *energy settlement quantity* for the *market trading node* is the negative of the amount determined for the corresponding *generator node* in clause 3.13.6.1(b).
- (d) If the net metered flows registered through a meter is inconsistent with the expected power flows at the *market trading node* to which that meter is associated, the *Metering Services Provider* shall determine and shall notify the *Market Operator* and the relevant *Trading Participant* the appropriate manner of determining the



gross settlement quantity for that *market trading node*.

(Added per DOE Circular No. DC 2013-07-0017 dated 26 July 2013)

3.13.7 Energy Settlement Quantity Adjustments for Bilateral

For settlement purposes, the energy settlement quantity for any *market trading node* in any *trading interval* shall be determined by the *Market Operator* by adjusting the gross energy settlement quantity for that *market trading node* and any *trading interval*, as measured in accordance with clause 3.13.5 for bilateral contract quantities notified to the *Market Operator* under clause 3.13.1.1, or inferred by the *Market Operator* under clause 3.13.1.1 and accepted as valid under clause 3.13.1.2 by: (As amended by DOE DC No. 2005-11-010 dated 11 November 2005) (As amended by DOE DC No. 2013-03-0005 dated 22 March 2013)

- (a) Subtracting all *bilateral sell quantities* notified for that node in that *trading interval* from the measured or estimated gross energy settlement quantity for that node in that *trading interval*; and
- (b) Adding all *bilateral buy quantities* inferred for that node in that *trading interval* to the measured or estimated gross energy settlement quantity for that node in that *trading interval*.

3.13.9 Determining the Energy Trading Amount

For settlement purposes, the energy trading amount for each *market trading node* and *trading interval* will be determined as:

- (a) The *energy settlement price* determined in accordance with clause 3.10.9 for that node in that *trading interval* multiplied by the gross energy settlement quantity for that node in that *trading interval* (in MWh) determined in accordance with clause 3.13.6 and as adjusted in



accordance with clause 4.5.2.2; (As amended by DOE DC No. 2013-03-0005 dated 22 March 2013) minus

- (b) The *energy settlement price* determined in accordance with clause 3.10.9 for that *node* in that *trading interval* multiplied by the gross *energy settlement quantity* for that node in that *trading interval* (in MWh) determined in accordance with clause 3.13.6. (As amended by DOE DC No. 2013-03-0005 dated 22 March 2013)

3.13.10 Determining the Reserve Trading Amount

- 3.13.10.1 For settlement purposes, the *reserve-trading amount* for each *Trading Participant* who supplies *reserve* to a particular *reserve region* in a *dispatch interval* will be determined as the *zonal reserve dispatch interval price* for that *reserve region* in that *dispatch interval* multiplied by the *zonal reserve settlement quantity* for that *Trading Participant* in that *reserve region* for that *dispatch interval*.
- 3.13.10.1A Settlements reserve trading amounts on a *trading interval* basis will be determined based on the summation of reserve-trading amounts determined under clause 3.13.10.1 for the corresponding *dispatch intervals*.
- 3.13.10.2 During the initial operation of the *interim WESM*, the *reserve trading amount* shall be calculated based on the cost of reserves contracted for by the *System operator*.

3.13.11 Determining the Reserve Cost Recovery Charge

The *reserve cost recovery charge* for settlement purposes will be determined for each *Trading Participant* in each *dispatch interval* in accordance with the procedures developed under clause 3.3.5.



3.13.12 Calculation of Line Rental Trading Amounts

The *Market Operator* shall calculate the line rental trading amounts for each bilateral contract associated with the delivery of the bilateral contract quantities (BCQ) through the *transmission line* in the *market network model* as: (As amended by DOE DC No. 2013-03-0005 dated 22 March 2013)

- (a) The expected flow of energy out of the *receiving node* of the *market net work line* as determined by the *market dispatch optimization model* multiplied by the *nodal energy settlement price* at that node; less (As amended by DOE DC No. 2005-11-010 dated 11 November 2005)
- (b) The expected flow of energy into the sending node multiplied by the *nodal energy settlement price* at that node of the *market network line* as determined by the *market dispatch optimization model*.

3.13.13 Determining the Transmission Rights Trading Amount

For *settlement* purposes, the *transmission right trading amount* for each *transmission right* in each *trading interval* is to be determined as:

- (a) The MWh capacity of that *transmission right* in that *trading interval* as notified under clause 3.13.2, multiplied by the *ex ante energy settlement price* for the *receiving node* in that *trading interval*; minus the sum of
- (b) The MWh capacity of that *transmission right*, in that *trading interval*, as notified under clause 3.13.2, multiplied by the *ex ante energy settlement price* at the *sending node* in that *trading interval*; plus
- (c) The MWh capacity of that *transmission right* in that *trading interval*, as notified under clause 3.13.2, multiplied by the agreed loss differential for that *transmission right*, as notified under clause 3.13.2,



multiplied by the *ex ante energy settlement price* at the *receiving node* in that *trading interval*.

3.13.14 Settlement Amounts for Trading Participants

3.13.14.1 For each *billing period*, the *Market Operator* shall determine the *settlement amount* for each *Trading Participant* as the sum of the aggregate trading amounts for the *trading intervals* in that *billing period*, determined in accordance with clause 3.13.14.2: plus [\(As amended by DOE DC No. 2005-11-010 dated 11 November 2005\)](#)

- (a) Any amount payable by the *Market Operator* to that *Trading Participant* in respect of that *billing period* and not accounted for in clause 3.13.14.2, including payment for any *ancillary services* purchased on behalf of the *System operator*, less the sum of
- (b) Any *market fees* which that *Trading Participant* is required to pay in respect of that *billing period* as determined in accordance with clause 2.10; plus
- (c) Any other amounts payable by that *Trading Participant* to the *Market Operator* in respect of that *billing period*, including any *ancillary services cost recovery charges*.

3.13.14.2 The aggregate trading amount for a *Trading Participant* for a *trading interval* equals the sum of:

- (a) The *energy trading amounts* for each *market trading node* for which that *Trading Participant* is responsible calculated in accordance with clause 3.13.9 (which may



be positive or negative for any *Trading Participant*); plus

- (c) The *reserve trading amounts* for each *reserve region* into which that *Trading Participant* contributes *reserve* calculated in accordance with clause 3.13.10 (which will always be positive for both *Generation Companies* and *Customers*); plus
- (d) The *transmission right trading amounts* for each *transmission right* held by the *WESM Participant* calculated in accordance with clause 3.13.13 (which will typically be positive for any *Trading Participant*); less the sum of
- (e) The *reserve cost recovery charge* determined for that *Trading Participant* with respect to any *reserve cost recovery region* within which it has any facility connected calculated in accordance with the procedures developed under clause 3.3.5 (which will be positive for any *Trading Participant*); and
- (f) Any other *ancillary service cost recovery charges* determined for that *Trading Participant* in accordance with the procedures developed under clause 3.3.5 (which will be positive for any *Trading Participant*).

3.13.15 Deleted [\(As per DOE DC No. 2004-07-008 dated 7 July 2004\)](#)

3.13.16 Treatment of Remaining Settlement Surplus



- 3.13.16.1 If the transactions required by clauses 3.13.14.2 (a), (b) and (d), in aggregate, result in a surplus or deficit remaining, this will be known as the *net settlement surplus*. [\(As amended by DOE DC No. 2005-11-010 dated 11 November 2005\)](#)
- 3.13.16.2 The net settlement surplus:
- (a) May be retained by the Market Operator, to fund deficit as a result of transactions required in clauses 3.13.14, or may be flowed back to the Market Participants in accordance with the procedures to be developed under 3.13.16.3, or may be used by the Market Operator to establish and support the market for Financial Transmission Rights subject to the approval of the PEM Board; and,
[\(As amended by DOE DC No. 2004-07-008 dated 7 July 2004\)](#)
 - (b) Shall be clearly accounted for and taken into account when setting the allowable charges under any regulatory instruments applying to the *Market Operator* and the *System operator*.
- 3.13.16.3 The Market Operator shall: [\(Amended by DOE DC No. 2004-07-008 dated 7 July 2004\)](#)
- (a) Publish regular summary reports on the amount of any net settlement surplus being generated;
 - (b) within one year from spot market commencement date, and every year thereafter, publish a review of the underlying factors giving rise to any net



settlement surplus, and attempt to identify any binding constraints which may have caused or contributed to such net settlement surplus;

- (c) Determine, in consultation with Trading Participants and Network Service Providers, and subject to approval by the PEM Board, whether the net settlement surplus generated by any particular set of constraints is of such magnitude as to justify development of a regime similar to that implemented in the WESM Rules with respect to transmission line rentals and transmission rights.
- (d) Develop procedures on the possible uses of net settlement surplus subject to approval by the PEM Board; and,
- (e) Continuously review the procedures on possible uses of net settlement surplus to the extent the Market Operator considers it to be reasonably necessary to promote WESM objectives. Any changes made on the procedures shall have approval from the PEM Board.

3.13.17 Settlement Amounts for Trading Participants with Bilateral Contracts

(Added as per DOE DC No. 2004-07-008 dated 7 July 2004)

- 3.13.17.1 For each billing period, the Market Operator shall determine the settlement amount for each trading participant with bilateral contract as the sum of the aggregate trading amounts for the trading intervals in that billing period, determined in



accordance with clause 3.13.17.2 plus: **(As amended by DOE DC No. 2013-03-0005 dated 22 March 2013)**

- (a) Any amount payable by the Market Operator to that Trading Participant in respect of that billing period and not accounted for in clause 3.13.17.2, including payment for any ancillary services purchased on behalf of the System operator, less the sum of
- (b) Any market fees which that Trading Participant is required to pay in respect of that billing period as determined in accordance with clause 2.10; plus
- (c) Any other amounts payable by that Trading Participant to the Market Operator in respect of that billing period, including any ancillary services recovery charges.

3.13.17.2 The aggregate trading amount for a Trading Participant for a trading interval equals the sum of:

- (a) The energy trading amounts for each market trading node for which the Trading Participant is responsible calculated in accordance with clauses 3.13.7 and 3.13.9 (which will typically be positive or negative for any Trading Participant); plus
- (c) The line rental trading amount corresponding to the quantity of bilateral contract of that Trading Participant calculated in accordance with clause 3.13.12; plus
- (d) The reserve trading amounts for each reserve region into which that Trading



Participant contributes reserve calculated in accordance with clause 3.13.10 (which will always be positive for both Generation Companies and Customers); plus

- (e) The transmission right trading amounts for each transmission right held by the WESM Participant calculated in accordance with clause 3.13.13 (which will always be positive for both Generation Companies and Customers); plus
- (f) The reserve cost recovery charge determined for that Trading Participant with respect to any reserve cost recovery region within which it has any facility connected calculated in accordance with the procedures developed under clause 3.3.4 (which will be positive for any Trading Participant); and
- (g) Any other ancillary service cost recovery charges determined for that Trading Participant in accordance with the procedures developed under clause 3.3.4.

3.14 SETTLEMENT PROCESS

3.14.1 Settlements Management by Market Operator

The *Market Operator* shall determine the *settlement* amount payable by

WESM members and facilitate the billing and *settlement* of transactions between itself and the *WESM members* under the *WESM Rules* in accordance with this clause 3.14.

3.14.2 Electronic Funds Transfer



3.14.2.1 The *Market Operator* shall ensure that an EFT facility is provided and made available for all *WESM members* for the purposes of facilitating *settlements* and the collection and payment of all *market fees*.

3.14.2.2 Unless otherwise authorized by the *Market Operator*, all *WESM Members* shall use the EFT facility provided by the *Market Operator* under clause 3.14.2.1 for the *settlement* of transactions and the payment of *market fees*.

3.14.3 Payment of Settlement Amount

3.14.3.1 Where the *settlement* amount for a *WESM member* is a negative amount, the *WESM member* shall pay that amount to *Market Operators* accordance with clause 3.14.6.3.14.3.2 Where the *settlement* amount for a *WESM member* is a positive amount, *Market Operator* shall pay that amount to the *WESM Member* in accordance with clause 3.14.7.

3.14.4 Preliminary Statements

3.14.4.1 Within 7 *days* after the end of each billing period, the *Market Operator* shall give each *WESM member* who has engaged in *market transactions* in that billing period a preliminary statement which sets out the *market transactions* of that *WESM member* in that billing period and the settlement amount payable by or to that *WESM member*. (As amended by DOE DC No. 2013-03-0005 dated 22 March 2013)

If the seventh day falls on a *Non-Working Day*, the issuance of the preliminary statements shall be made during the next immediate *Working Day*.



(Added per DOE DC No. 2013-03-0005 dated 22 March 2013)

- 3.14.4.2 The statements issued under this clause 3.14.4 shall include supporting data for all amounts payable sufficient to enable each *WESM member* to audit the calculation of the amount payable by or to that *WESM member*.
- 3.14.4.3 If the *WESM member* reasonably believes there was an error or discrepancy in the preliminary statement given to the *WESM Member* by the *Market Operator* under this clause 3.14.4, the *WESM member* shall notify the *Market Operator* as soon as practicable of that error or discrepancy and the *Market Operators* shall review the preliminary statement.
- 3.14.4.4 If the *Market Operator* considers that a preliminary statement contains an error or discrepancy after reviewing the preliminary statement as notified by a *WESM member* pursuant to clause 3.14.4.3 or as independently identified by the *Market Operator*, the *Market Operator* shall ensure that correction of any error or discrepancy is reflected in the relevant final statements, provided that corrections requiring the input of an external party are received by the *Market Operator* at least two *Working Days* before the deadline of the issuance of the final statements. If the *Market Operator* receives notice of an error, discrepancy or correction of an earlier identified error after their relevant deadlines, clause 3.14.9.2 shall apply. (As amended by DOE DC No. 2013-03-0005 dated 22 March 2013)



3.14.5 Final Statements

3.14.5.1 No later than eighteen *days* after the end of each billing period, the *Market Operator* shall give to each *WESM member* who has engaged in *market transactions* in that billing period a final statement stating the amounts payable by the *WESM member* to the *Market Operator* or payable by the *Market Operator* to the *WESM member* in respect of the relevant billing period. (As amended by DOE DC No. 2013-03-0005 dated 22 March 2013)

If the eighteenth day falls on a *Non-Working Day*, the issuance of the final statements shall be made during the next immediate *Working Day*. (Added per DOE DC No. 2013-03-0005 dated 22 March 2013)

3.14.5.2 The statements issued under this clause 3.14.5 shall include supporting data for all amounts payable which shall be sufficient to enable each *WESM member* to audit the calculation of the amount payable by or to that *WESM member*.

3.14.6 Payment by Trading Participants

No later than 3.00 pm on the twenty-fifth day of the calendar month following the billing period, each *WESM member* shall pay to the *Market Operator* in cleared funds the *settlement amount* (if any) stated to be payable to the *Market Operator* by that *WESM member* in that *WESM member's* final statement, whether or not the *WESM member* disputes, or continues to dispute, the



amount payable. (As amended by DOE DC No. 2013-03-0005 dated 22 March 2013)

If the twenty-fifth day of the calendar month following the billing period falls on a *Non-Working Day*, the payment due date shall be moved to the next immediate *Working Day*. (Added per DOE DC No. 2013-03-0005 dated 22 March 2013)

3.14.7 Payment to Trading Participants

On the following *Working Day* after the *Market Operator* is to be paid under clause 3.14.6, and in accordance with the schedule set in the billing and settlements timetable, the *Market Operator* shall pay to each *WESM member* in cleared funds the settlement amount (if any) stated to be payable in that *WESM member's* final statement. (As amended by DOE DC No. 2013-03-0005 dated 22 March 2013)

The maximum total payment which the *Market Operator* is required to pay in respect of any billing period is equal to the aggregate of-

- a) the total payments actually received from *WESM Members* in accordance with clause 3.14.6; *plus*
- b) the total amount that the *Market Operator* is able to actually draw from the prudential security of the defaulting *WESM Members* in accordance with clause 3.15, if one or more *WESM Member* is in default; *plus*
- c) other sources of funds which the PEM Board may approve to be the paid to the *WESM Members* if the total amount drawn from the prudential security deposit of the defaulting *WESM Members* is insufficient to cover the defaulted amounts.



If it becomes necessary for the *Market Operator* to draw upon the prudential security of a defaulting *WESM Member* in accordance with clause 3.15, the corresponding payments to the *WESM Members* entitled to be paid shall be made only after the *Market Operator* is actually able to draw on the prudential security but not later than the date specified in the billing and settlement time table.

If the total payments actually received or drawn from the prudential security by the *Market Operator* for a particular billing period is insufficient to pay for the total amounts payable to the *WESM Members*, the total payments received and drawn shall be distributed and paid to the relevant *WESM Members* in proportion to the amount payable to them for that billing period.

The shortfall shall be paid upon collection from the defaulting *WESM Member* but not later than the date specified in the billing and settlement time table.

[\(As amended by DOE DC No. 2005-11-010 dated 11 November 2005 and further amended by DOE DC No. 2006-11-0013 dated 09 November 2006\)](#)

3.14.8 Disputes

3.14.8.1 If a dispute arises between a *WESM member* and the *Market Operator* concerning either:

- (a) The *settlement* amount stated in any preliminary statement provided under clause 3.14.4 to be payable by or to it; or
- (b) The supporting data, they shall each use reasonable endeavors to resolve the dispute within fifteen *business days* after the end of the relevant billing period.



3.14.8.2 Disputes in respect of *final statements* or the supporting data provided with them in accordance with clause 3.14.5 shall be raised within twelve months of the relevant billing period.

3.14.8.3 Disputes raised under this clause 3.14.8 shall be resolved by agreement or pursuant to the dispute resolution procedures set out in clause 7.3.

3.14.9 Settlement Revisions

3.14.9.1 If an amount in a *final statement* issued under clause 3.14.5:

- (a) Has been the subject of a dispute and the dispute has been resolved; or
- (b) Was subject of a pending case before a Court of competent jurisdiction and that said Court has already rendered a final and executory Decision;

If any of the abovementioned cases has caused a different amount payable as set out in the *final statement*, the *Market Operator* shall issue to each *WESM Member* affected, an adjustment to the *final statement* for the relevant billing period setting out:

- (a) The amount payable by the *WESM Member* to the *Market Operator* or the amount payable by the *Market Operator* to the *WESM Member*, and
- (b) Interest calculated on a daily basis at the interest rate for the *final statement* to which the adjustment relates to the payment date applicable to the revised statement issued under this clause 3.14.9.1.



The *Market Operator* shall issue the adjustment to the *final statement* not later than twelve (12) calendar months after the resolution of the dispute or receipt of the relevant final and executory Order unless parties to be billed agrees that the issuance of the particular WESM bill adjustment shall be at a later time.

[\(As amended by DOE DC No. 2011-12-0011 dated December 2011\)](#)

- 3.14.9.2 If the *Market Operator* becomes aware of an error in an amount stated in a *final statement* issued under clause 3.14.5 and, in the *Market Operator's* reasonable opinion, a *WESM Member* would be materially affected if a revision to the *final statement* was not made to correct the error, then the *Market Operator* shall issue the Revised Statement not later than six (6) calendar months from receipt of the *Market Operator* of written notice of error from the participant, or from the *Market Operator's* discovery of the same.

[\(As amended by DOE DC No. 2011-12-0011 dated December 2011\)](#)

3.14.10 Payment of Adjustments

- 3.14.10.1 The *Market Operator* shall specify the time and date on which a payment of an adjustment under a revised statement issued under clause 3.14.9 is due, which date shall be not less than ten *business days* and not more than fifteen *business days* after the issue of that revised statement.
- 3.14.10.2 By no later than the time and date specified by the *Market Operator* pursuant to clause 3.14.10.1, each *WESM member* shall pay to the *Market*



Operator in cleared funds the net amount (if any) stated to be payable by that *WESM member* in the revised statement issued to it under clause 3.14.9.

- 3.14.10.3 On the following *Working Day* on which the *Market Operator* is to be paid under clause 3.14.10.2, the *Market Operator* shall pay to each *WESM Member* in cleared funds the net amount (if any) stated to be payable to that *WESM member* in the revised statement issued to it under clause 3.14.9. **(As amended by DOE DC No. 2013-03-0005 dated 22 March 2013)**

3.14.11 Payment Default Procedure

- 3.14.11.1 Each of the following events is a default event in relation to a *WESM member*.
- (a) The *WESM member* does not pay any money due for payment by it under the *WESM Rules* by the appointed time on the due date;
 - (b) The *Market Operator* does not receive payment in full of any amount claimed by the *Market Operator* under any credit support in respect of a *WESM member*, within ninety minutes after the due time for payment of that claim;
 - (c) The *WESM member* fails to provide credit support required to be supplied under the *WESM Rules* by the appointed time on the due date;
 - (d) It is or becomes unlawful for the *WESM member* to comply with any of its obligations under the *WESM Rules* or any other obligation owed to the *Market*



Operator or it is claimed to be so by the *WESM member*,

- (e) It is or becomes unlawful for any *Credit Support Provider* in relation to the *WESM member* to comply with any of its obligations under the *WESM Rules* or any other obligation owed to the *Market Operator* or it is claimed to be so by that *Credit Support Provider*,
- (f) An authorization from a government authority necessary to enable the *WESM member* or a *Credit Support Provider* which has provided credit support for that *WESM member* to carry on their respective principal businesses or activities ceases to have full force and effect;
- (g) The *WESM member* or a *Credit Support Provider* which has provided credit support for that *WESM member* ceases or is likely to cease to carry on its business or a substantial part of its business;
- (h) The *WESM member* or a *Credit Support Provider* which has provided arrangement (including a scheme of arrangement), composition or compromise with, or assignment for the benefit of, all or any class of their respective creditors or members, or a moratorium involving any of them;
- (i) The *WESM member* or a *Credit Support Provider* which has provided credit support for that *WESM member* states that it is



unable to pay from its own money its debts as and when they fall due for payment;

- (j) A receiver or receiver and manager is appointed in respect of any property of the WESM member or a *Credit Support Provider* which has provided credit support for that WESM member,
- (k) An administrator, provisional liquidator, liquidator, trustee in bankruptcy or person having a similar or analogous function is appointed in respect of the WESM member or a Credit Support Provider which has provided credit support for that WESM member, or any action is taken to appoint any such person;
- (l) An application or order is made for the winding up or dissolution or a resolution is passed or any steps are taken to pass a resolution for the winding up or dissolution of the WESM member or a Credit Support Provider which has provided credit support for that WESM member,
- (m) The WESM member or a Credit Support Provider which has provided credit support for that WESM member dies or is dissolved unless such notice of dissolution is discharged; and
- (n) The WESM member or a Credit Support Provider which has provided credit support for that WESM member is taken to be insolvent or unable to pay its debts under any applicable legislation.



3.14.11.2 Where a default event has occurred in relation to a *WESM member*, the *Market Operator* may:

- (a) Issue a default notice which specifies:
 - (1) The nature of the alleged default; and
 - (2) If the *Market Operator* considers that the default is capable of remedy, that the *WESM member* shall remedy the default within 24 hours of the issue of the default notice; and/or
- (b) Immediately issue a suspension notice in accordance with clause 3.15.7 if the *Market Operator* considers that the default is not capable of remedy and that failure to issue a suspension notice would be likely to expose other *WESM members* to greater risk; and/or
- (c) If it has not already done so, make a claim upon any credit support held in respect of the *WESM member* for such amount as the *Market Operator* determines represents the amount of any money actually or contingently owing by the *WESM member* to the *Market Operator* pursuant to the *WESM Rules*.

3.14.11.3 If:

- (a) The *Market Operator* considers that a default event is not capable of remedy; or
- (b) A default event is not remedied within 24 hours of the issue of the default notice or any later deadline agreed to in writing by the *Market Operator*, or



- (c) The *Market Operator* receives notice from the defaulting *WESM member* that it is not likely to remedy the default specified in the default notice, then the *Market Operator* may issue a suspension notice in accordance with clause 3.15.7 under which the *Market Operator* notifies the defaulting *WESM member* that it is prohibited from participating in the *spot market*.

3.14.12 Interest on Overdue Amounts

If a *Trading Participant* fails to pay any amount due and payable by it under the *WESM Rules*, such overdue amount shall bear the default interest rate reckoned from the first day such amount is due and payable, up to and including the date on which payment is made, with interest computed based on a 360-day year.

3.15 PRUDENTIAL REQUIREMENTS

3.15.1 Purpose

The purpose of the *prudential requirements* is to ensure the effective operation of the *spot market* by providing a level of comfort that *WESM members* will meet their obligations to make payments as required under the *WESM Rules*.

3.15.2 Provision of Security

- 3.15.2.1 Subject to clause 3.15.2.2, a *Trading Participant* wishing to participate in *market transactions* shall provide and maintain a security complying with the requirements of this clause 3.15.2.
- 3.15.2.2 The *Market Operator* may exempt *WESM members* from the requirement to provide a security under clause 3.15.2.1, if:
 - (a) the *Market Operator* believes it is likely that the amount payable by the *Market Operator*



to that *WESM Member* under the *WESM Rules* will consistently exceed the amount payable to the *Market Operator* by that *WESM member* under the *WESM Rules* in respect of that period; or

- (b) the *Market Operator* believes it is unlikely that the *WESM member* will be required to pay any amounts to the *Market Operator*; or
- (c) Deleted [\(As per DOE DC No. 2004-07-008 dated 7 July 2004\)](#)

3.15.2.3 If, under clause 3.15.2.2, the *Market Operator* has exempted a *WESM member* from the requirement to provide a security under clause 3.15.2.1, then the *Market Operator* may vary or cancel the exemption at any time by giving written notice of the variation or cancellation of the exemption to the *WESM member*.

3.15.3 Form of Security

The security provided by a *WESM member* under this clause 3.15 shall be either:

- (a) A bank guarantee in a form and from a bank acceptable to the *Market Operator*; or
- (b) Another immediate, irrevocable and unconditional commitment in a form and from a bank or other institution acceptable to the *Market Operator*, or
- (c) Surety Bond issued by a surety or insurance company duly accredited by the Office of the Insurance Commissioner of the Philippines.
- (d) Such other forms of security or guarantee acceptable to the *Market Operator*.

(Added as per DOE DC No.2006-07-0010 dated 20 July

2006)



3.15.4 Amount of Security

- 3.15.4.1 Subject to clause 3.15.2.2, prior to the end of each *financial year* the *Market Operator* shall determine and provide written confirmation to each *WESM member* of its maximum exposure to the *Market Operator* in respect of a billing period in the following *financial year*.
- 3.15.4.2 The *Market Operator* may review its determination of a *WESM member's* maximum exposure at any time, provided that any change to a *WESM member's* maximum exposure will apply no earlier than thirty days following notification by the *Market Operator* to that *WESM member* of that change or such earlier period agreed by the *PEM Board*.
- 3.15.4.3 Each *WESM member* shall ensure that at all times the aggregate undrawn and unclaimed amounts of current and valid security held by the *Market Operator* in respect of that *WESM member* is not less than that *WESM member's* maximum exposure.
- 3.15.4.4 To diminish the possibility of incurring a *margin call* under clause 3.15.10, a *WESM member* may in its absolute discretion provide to the *Market Operator* a security or securities in accordance with clause 3.15.3 for an aggregate amount, which exceeds its maximum exposure.

3.15.5 Replacement Security

- 3.15.5.1 If:
 - (a) An existing security provided by a *WESM member* under this clause 3.15 is due to expire or terminate; and



- (b) After that security expires or terminates, the maximum amount which the *Market Operator* will be entitled to be paid in aggregate under any remaining security or securities provided by the *WESM member* under this clause 3.15 will be less than *WESM member's* maximum exposure,
- (c) Then the *WESM member* shall deliver to the *Market Operator*, at least ten *business days* prior to the time at which that existing security is due to expire or terminate, a replacement security which:
 - (1) Is of sufficient value to enable the *WESM member* to comply with clause 3.15.4.3;
 - (2) Complies with the requirements of this clause 3.15; and
 - (3) Will take effect no later than the date on which the existing security is due to expire or terminate.

3.15.5.2 If:

- (a) A *WESM member* fails to comply with clause 3.15.5.1; and
- (b) That *WESM member* does not remedy that failure within 24 hours after being notified by the *Market Operator* of the failure, then the *Market Operator* shall give the *WESM member* a suspension notice in accordance with clause 3.15.7.

3.15.6 Drawdown of Security



- 3.15.6.1 If the *Market Operator* exercises its rights in accordance with this clause 3.15 under a security provided by a *WESM member* under this clause 3.15, then the *Market Operator* shall notify the *WESM member*.
- 3.15.6.2 If, as a result of the *Market Operator* exercising its rights under a security provided by a *WESM member* under this clause 3.15, the maximum amount which the *Market Operator* is entitled to be paid under the security or securities provided by the *WESM member* under this clause 3.15 is less than the *WESM member's* maximum exposure, then, within 24 hours of receiving a notice under clause 3.15.6.1, the *WESM member* shall provide an additional security to ensure that at all times, it complies with the requirements of this clause 3.15.
- 3.15.6.3 If a *WESM member* fails to comply with clause 3.15.6.2 within the time period referred to in that clause, then the *Market Operator* shall give the *WESM member* a suspension notice in accordance with clause 3.15.7.

3.15.7 Suspension of a WESM member

- 3.15.7.1 As soon as practicable after a suspension notice is issued by the *Market Operator* under the *WESM Rules*, the *Market Operator* shall:
- (a) *Publish the suspension notice; and*
[\(As amended by DOE DC No.2005-11-010 dated 11 November 2005\)](#)
 - (b) Place a notice in a newspaper of general circulation that the *WESM member* has been suspended.



- 3.15.7.2 The *Market Operator* shall revoke a suspension notice if:
- (a) In the case of a default event, the default event is remedied; or
 - (b) In the case of a failure to maintain compliance with prudential requirements under this clause 3.15, that failure has been remedied; and
 - (c) There are no other circumstances in existence, which would entitle the *Market Operator* to issue a suspension notice, except that the *Market Operator* shall not revoke a suspension notice more than one month after it was issued.
- 3.15.7.3 If a suspension notice is revoked, the Market Operator shall publicize that fact in the same manner in which the suspension notice was publicized in accordance with clause 3.15.7.1.
- 3.15.7.4 From the time that the Market Operator issues a suspension notice to a WESM member under the WESM Rules, the WESM member is ineligible to participate in the *spot market*, until such time as the *Market Operator* notifies the *WESM member* and all other relevant *Trading Participants* that the suspension notice has been revoked.
- 3.15.7.5 A *WESM member* shall comply with a suspension notice issued to it under the *WESM Rules*.
- 3.15.7.6 If:
- (a) The Market Operator has issued a suspension notice to a WESM member due to a default event and in the Market Operator's reasonable opinion the WESM member is



incapable of rectifying the default event for any reason; or

- (b) The Market Operator has issued a suspension notice to a WESM member due to a failure by the WESM member to continue to satisfy the prudential requirements and in the Market Operator's reasonable opinion the WESM member is incapable of rectifying that failure for any reason, the *Market Operator's* shall deregister that *WESM member* as soon as practicable and promptly *publish* a notice of that fact.

[\(As amended by DOE DC No.2005-11-010 dated 11 November 2005\)](#)

3.15.8 Trading Limits

3.15.8.1 Subject to clause 3.15.8.2, the Market Operator shall set a trading limit for each WESM member who participates in market transactions.

3.15.8.2 If, under clause 3.15.2.2, the Market Operator has exempted a Trading Participant from the requirement to provide a security under clause 3.15.2.1 for a period, then the Market Operator shall not set a trading limit for that WESM Member for the period during which that exemption applies.

3.15.8.3 The trading limit for a WESM Member at any time shall not be greater than 95% of the total value of the security provided by the WESM Member to the Market Operator under clauses 3.15.3 (a), (b) and (c).

[\(As amended by DOE DC No.2006-07-0010 dated 20 July 2006\)](#)



3.15.9 Monitoring

- 3.15.9.1 Each day, the Market Operator shall review its actual exposure to each WESM Member in respect of previous billing periods under the WESM Rules.
- 3.15.9.2 In calculating the Market Operator's actual exposure to a WESM Member under clause 3.15.9.1, the period between the start of the billing period in which the review occurs and the start of the trading day immediately following the day on which the review occurs is to be treated as a previous billing period.
- 3.15.9.3 In calculating the Market Operator's actual exposure to a WESM Member under clause 3.15.9.1, the Market Operator shall take into account:
 - (a) Outstanding settlement amounts for the WESM Member in respect of previous billing periods; and
 - (b) Settlement amounts for the WESM Member for trading intervals from the start of the billing period in which the review occurs to the end of the trading day on which the review occurs based on:
 - (1) Actual market prices or, if actual market prices are not available for all or part of a trading day, the market prices forecast for the relevant trading day as specified in the relevant day ahead projection; and
 - (2) Actual metered quantities for the WESM Member or, if actual metered quantities are not available for a trading interval, then a trading



imbalance for that trading interval determined by the Market Operator as the average of the trading imbalances of that WESM Member for the corresponding trading interval on the corresponding trading days of the four previous weeks.

- 3.15.9.4 If the Market Operator calculates that its actual exposure to a WESM Member exceeds the WESM Member's trading limit, then the Market Operator shall notify the WESM Member accordingly.

3.15.10 Margin Calls

- 3.15.10.1 If the *Market Operator* calculates that its exposure to a *WESM member* exceeds the *WESM member's trading limit*, then the *Market Operator* shall make a margin call on that *WESM member* by notice to the *WESM member*.
- 3.15.10.2 If the *Market Operator* makes a *margin call* on a *WESM member* under clause 3.15.10.1, then the *WESM member* must satisfy the *margin call* within the period determined in accordance with clause 3.15.10.3 by either:
- (a) Providing to the Market Operator an additional security or securities complying with the requirements of this clause 3.15 which enables the Market Operator to increase the WESM member's trading limit to a level which exceeds the Market Operator's actual exposure to the WESM member, or



- (b) Prepaying a portion of the amount payable or which will become payable in respect of previous billing periods sufficient to reduce the *Market Operator's* actual exposure to the *WESM member* to below the *WESM member's trading limit*.
- 3.15.10.3 The period within which a margin call must be satisfied under clause 3.15.10.2 is:
 - (a) If the margin call is made on a business day before 10:00 am, then the period commences at the time the margin call is made and finishes at 3:00 pm on that business day; and
 - (b) If clause 3.15.10.3 (a) does not apply, then the period commences when the margin call is made and ends at 10:00 am on the first business *day* to occur after the *margin call* is made.
- 3.15.10.4 For the purposes of the *WESM Rules*, a prepayment under clause 3.15.10.2(b) is taken to relate to the earliest billing period in respect of which the relevant *WESM member* owes the *Market Operator* an amount of money under the *WESM Rules* and, if the amount the *WESM member* owes under the *WESM Rules* in respect of that billing period is less than the amount of the prepayment, then the excess is taken to relate to the billing periods occurring immediately after the earliest billing period in respect of which the relevant *WESM member* owes the *Market Operator* an amount of money under the *WESM Rules* in chronological order until there is no excess.



3.15.10.5 If a *WESM member* fails to satisfy a margin call by providing an additional security or making a prepayment under clause 3.15.10.2 within the time referred to in that clause, then the *Market Operator* shall give the *WESM member* a suspension notice.

3.15.11 Confidentiality

All information provided by a *WESM member* in relation to its financial circumstances shall be treated by the *Market Operator* as confidential information in accordance with clause 5.2.

