PUBLIC

WESM Manual

Price Determination Methodology Issue No.1

Abstract	Provides the mechanism for determining the prices and settlements in the Philippine Wholesale Electricity Spot Market.

Document Identity: WESM-PDM-001

Issue No.: 1

Reason for Issue: Implementation of WESM enhancements in operations and design

Approval Date:
Publication Date:
Effective Date:

Document Change History

Issue No.	Proponent	Date of Effectivity	Reason for Amendment
	PEMC	26 June 2006	Original document, as approved by the ERC on 20 June 2006 under ERC Decision on Case No. 2006-007 RC
1	PEMC		Implementation of enhancements to WESM design and operations; Consolidated the following WESM Manuals in the PDM: 1. Procedure for Determining Ex-Post Nodal Energy Prices (EPNEP), Issue 2 2. Methodology for Determining Pricing Errors and Price Substitution Due to Congestion for Energy Transactions in the WESM (PSM), Issue 4 3. Administered Price Determination Methodology (APDM), Issue 5 4. Segregation of Line Rental Trading Amounts (SLRTA), Issue 1 5. Management Net Settlement Surplus, Issue 2 6. Management of Must-run and Must-stop Units (MRU Manual), Issue 6

Document Approval

Issue No.	RCC Approval	RCC Resolution No.	PEM Board Approval	PEM Board Resolution No.
1				

Reference Documents

Document ID	Document Title
	Electric Power Industry Reform Act (EPIRA)
	WESM Rules
	Market Manuals

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SECTION 1 INTRODUCTION

1.1 Background

1.1.1 The establishment of the Philippine *Wholesale Electricity Spot Market* (the "WESM") is mandated by Republic Act No. 9136, otherwise known as the "Electric Power Industry Reform Act of 2001" (the "EPIRA").

1.1.2 Pursuant to the mandate of the EPIRA, the *Department of Energy* (the "*DOE*") jointly with the electric power industry participants formulated the *WESM Rules*, which, among other things, provides the mechanism for determining the prices of electricity in the market not covered by *bilateral contracts*.

1.1.3 This Price Determination Methodology Manual provides the specific details of such mechanism. It is formulated compliant with the *WESM Rules*, in consultation with the industry participants, and approved by the *Energy Regulatory Commission* (the "*ERC*").[1]

1.2 Purpose

1.2.1 The price determination methodology and *settlement* formula in this *Market Manual* shall ensure that the following characteristics and pricing principles of the *WESM* are achieved**:**

a. Gross pool, where each *scheduled generation company* offer their *maximum available capacity*, *non-scheduled generation company* submit a standing nomination of *loading levels*, and *Trading Participants* with *must dispatch generating units* and *priority dispatch generating units* submit *projected outputs* for central scheduling and *dispatch,* to ensure *system security* and a level-playing field among *generators*;[2]
b. Net settlement, where *bilateral contract* quantities are settled outside the *WESM*;[3]
c. Co-optimized *energy* and *reserves*, where the provision of *energy* and *reserves* are jointly optimized in the *market dispatch optimization model*;[4]
d. Self-commitment, where *Trading Participants* are responsible for the management of their technical operations, unit commitment decisions and other market risks through submission of bids and offers to the *WESM*;[5]
e. Prices are governed, as far as practicable, by commercial and market forces;[6]
f. Full nodal or *locational marginal pricing* regime in *energy* for both *generator market trading nodes* and *customer market trading nodes*, to provide economic signals that properly account the economic impact of losses and *constraints* that resulted from the operation of the electricity market;[7]

[1] *WESM Rules* Clause 3.2
[2] *WESM Rules* Clauses 1.2.5 and 3.5.5
[3] *WESM Rules* Clause 3.13
[4] *WESM Rules* Clause 3.6
[5] *WESM Rules* Clause 3.5
[6] *WESM Rules* Clause 1.2.5
[7] *WESM Rules* Clauses 3.2.2 and 3.6.1

g. Zonal pricing for *reserves*;[8]
h. *Trading Participants* are provided with regularly updated information on projected prices, *dispatch* and other market outcomes to ensure they can make informed commercial and technical decisions;[9] and
i. Other principles that are contained in the issuances of the *DOE* insofar as these principles are consistent with the objectives of applicable laws.

1.3 Scope

1.3.1 This *Market Manual* provides the principles and methodology by which *energy* and *reserves* in the *WESM* shall be priced,[10] including the determination of prices when there is extreme price separation due to *network congestion*,[11] and determination of *administered prices* during *market suspension* and *market intervention.*[12]

1.3.2 This *Market Manual* provides the principles and methodology by which *energy* and *reserves* shall be settled in the *WESM*, including the cost recovery for *reserves,* the determination of additional compensation, as applicable, and the determination and allocation of *net settlement surplus.*[13]

1.3.3 This *Market Manual* provides the principles and methodology by which *energy* and *reserves* shall be priced and settled in accordance with the market design principles as issued by the *DOE.*[14]

1.3.4 This *Market Manual* provides the computational formula that will enable the *WESM participants* to verify the correctness of the charges being imposed.

SECTION 2 DEFINITIONS, REFERENCES AND INTERPRETATION

2.1 Definitions

2.1.1 Unless otherwise defined or the context implies otherwise, the italicized terms used in this *Market Manual* shall bear the same meaning as defined in the *WESM Rules* and other *Market Manuals*.

2.1.2 The following words and phrases as used in this *Market Manual* shall have the following meaning –

a. **Algorithm.** The process/processes applied by the *market dispatch optimization model* in computing the *dispatch schedules* and prices.

[8] *WESM Rules* Clause 3.6.1
[9] *WESM Rules* Clause 1.2.5
[10] *WESM Rules* Clause 3.10
[11] *WESM Rules* Clause 3.12.7
[12] *WESM Rules* Clause 6.2.3
[13] *WESM Rules* Clause 3.13
[14] *DOE* Circular 2015-10-0015, “Providing Policies for further Enhancement of the *Wholesale Electricity Spot Market (WESM)* Design and Operations”, dated 23 October 2015

b. **Constrained Solution.** A solution produced by the *market dispatch optimization model* considering all *constraints* based on the price determination methodology.

c. **Constrained-on Generators.** Generation units that were scheduled to run pursuant to the original market solution but would not have been cleared or cleared at a lower quantity based on the *unconstrained solution*.

d. **Economic gain.** The total benefit that will be received by the producers and consumers of electricity in the *security-constrained dynamic dispatch* optimization.

e. **Energy Administered Price**. The price used in lieu of the *nodal energy dispatch price* during *dispatch intervals* under *market suspension* or *market intervention.*

f. **Locational Marginal Pricing.** The mechanism by which the *nodal energy dispatch price* is determined.

g. **Network Congestion.** Refers to the congestion at a line or transformer that is connected in a meshed *network*.

h. **Network Data.** The electrical parameters used to represent the *transmission system* or *network* in the *market network model*.

i. **Reserve Administered Price.** The price used in lieu of the *reserve prices* during *dispatch intervals* under *market suspension* or *market intervention*

j. **Reserve Requirement.** MW level to be met for the various categories of *reserves*.

k. **Security-constrained dynamic dispatch.** Process of apportioning the total *load* on a system between the various *generating units* over a certain time period to achieve the greatest economy of operation and taking account of the limitations of the *power system*.

l. **Security limits.** Limits imposed by the *System Operator* on *generation* and transmission equipment to maintain *system security* and *reliability*.

m. **Self-scheduled energy.** Refers to *projected outputs* of *must dispatch* and *priority dispatch generating units*, and nomination of *loading levels* of *non-scheduled generating units*.

n. **System marginal price**. The shadow price for which *energy* is priced.

o. **Transmission Loss Factor.** Scaling factors applied on the *nodal energy dispatch prices* to account for the *network* loss associated with the delivery or consumption of *energy* at different locations in the system.

p. **Unconstrained Solution.** A co-optimized solution of the *market dispatch optimization model* that does not take into consideration the thermal limits of lines and transformers.

2.2 References

2.2.1 This *Market Manual* shall be read in association with the following:

a. *WESM Rules*
b. Dispatch Protocol Manual
c. Constraint Violation Coefficients and Pricing Re-Runs Manual
d. Market Operator Information Disclosure and Confidentiality Manual

2.3 Interpretation

2.3.1 Any reference to a clause in any section of this *Market Manual* shall refer to the particular clause of the same section in which the reference is made, unless otherwise specified or the context provides otherwise.

2.3.2 Standards and policies appended to, or referenced in, this *Market Manual* shall provide a supporting framework.

SECTION 3 RESPONSIBILITIES

3.1 Market Operator

3.1.1 The *Market Operator* shall be responsible for the development, validation, maintenance, publication, and revision of this *Market Manual* in coordination with *Trading Participants* and the *System Operator.*

3.1.2 The *Market Operator* shall implement the principles and processes provided in this *Market Manual*.

3.2 System Operator

3.2.1 The *System Operator* shall provide the necessary information and references for the implementation and subsequent revisions and validation of this *Market Manual.*

3.3 Trading Participants

3.3.1 The *Trading Participants* shall provide the necessary information and references for the implementation and subsequent revisions and validation of this *Market Manual.*

SECTION 4 DISPATCH AND PRICING ALGORITHM

4.1 Scope

4.1.1 This section provides an overview of the *dispatch* and pricing *algorithm* for *energy* and *reserves* in the *WESM.* The detailed formulation of the *algorithm* is provided for in Appendix A of this *Market Manual*.

4.2 Market Dispatch Optimization Model

4.2.1 The *WESM* shall employ a gross pool *dispatch* model where all submitted *generation offers*, *reserve offers*, *projected outputs*, nomination of *loading levels*, and *demand bids* are scheduled based on the mathematical optimization *algorithm* of the *market dispatch optimization model.*

4.2.2 The *market dispatch optimization model* shall perform computations in determining the market clearing price based on the information it receives on system conditions and *constraints* from the *System Operator*; *generation* and *reserve offers*, nomination of *loading levels*, *projected output* and *demand bids* from *Trading Participants*; and *load forecasts* from the *Market Operator*.

4.2.3 It shall process these information to come up with an optimum scheduling of *energy* and *reserves* that will maximize *economic gains* for the *Trading Participants* taking into consideration the physical limitations of the *transmission network* and of the *facilities* of the *Trading Participants*.

4.2.4 It shall utilize linear programming techniques to determine *dispatch schedules* and calculate *nodal energy dispatch prices* for all *market trading nodes* in the *market network model* and *reserve prices* for all *reserve regions*.

4.3 Required Inputs to the Market Dispatch Optimization Model

4.3.1 The *market dispatch optimization model* shall receive input data from three sources, namely, the *System Operator*, the *Trading Participants*, and the *Market Operator*. The information provided is as required in the *WESM Rules*[15].

4.3.2 *System Operator* Inputs:

a. *Network data;*
b. *System snapshot;*
c. *Outage* schedules;
d. *Contingency list;* and
e. *Over-riding constraints;*
    - *Security limits*
        - *Generation* limits
        - Branch group limits
    - *Must-run generation*

4.3.3 *Trading Participant* Inputs:

a. Registration data;
b. *Generation offers;*
c. *Demand bids;*
d. *Reserve offers;*
e. Schedule of *loading levels;*
f. *Projected output;* and

[15] *WESM Rules* Clause 3.5

g. Optional *load forecast.*

4.3.4 *Market Operator* Inputs:
a. *Market network model;*
b. *Reserve requirements;*
c. Nodal *load forecast;* and
d. *Constraint violation coefficient.*

4.4 Objective Function

4.4.1 The *market dispatch optimization model* shall maximize the *economic gain* derived from electricity trades in the market. This is defined to be the maximization of the value of dispatched *load* based on *demand bids*, minus the cost of dispatched *generation* based on *generation offers*, minus the cost of dispatched *reserves* based on *reserve offers*, minus the cost of *constraint* violation based on *constraint violation coefficients*.[16] It is represented by the following formulation:

Maximize the *economic gain* from trade, where:

$$\text{Economic Gain} = \sum_{i}^{n}\left\{\sum_{b}^{E_D}\left[\left(DB_{b,\,i}\right)\left(PDB_{b,\,i}\right)\right] - \sum_{k}^{E_G}\left[\left(G_{k,\,i}\right)\left(PG_{k,\,i}\right)\right] - \sum_{r}^{N_R}\sum_{j}^{E_R}\left[\left(R_{j,\,r,\,i}\right)\left(PR_{j,\,r,\,i}\right)\right] - \sum_{c}^{E_C}\left[\left(CQ_{c,\,i}\right)\left(CP_{c,\,i}\right)\right] - \sum CVP\right\}$$

Where:

i	refers to a specific *dispatch interval*
n	refers to the number of *dispatch intervals* involved in the solution
E_D	refers to the number of *demand bid* blocks in a *dispatch interval i*
E_G	refers to the number of *generation offer* blocks in a *dispatch interval i*
E_R	refers to the number of *reserve offer* blocks in a *dispatch interval i*
N_R	refers to the number of *reserve categories*
$DB_{b,\,i}$	refers to the *demand bid* block quantity *b* at *dispatch interval i*
$PDB_{b,\,i}$	refers to the *demand bid* block price *b* at *dispatch interval i*
$G_{k,\,i}$	refers to the *generation offer* block quantity *k* at *dispatch interval i*
$PG_{k,\,i}$	refers to the *generation offer* block price *k* at *dispatch interval i*
$R_{j,\,r,\,i}$	refers to the *reserve offer* block quantity *j* for *reserve category r* at *dispatch interval i*
$PR_{j,\,r,\,i}$	refers to the *reserve offer* block price *j* for *reserve category r* at *dispatch interval i*
$CQ_{c,\,i}$	refers to the curtailment quantity *c* at *dispatch interval i*
$CP_{c,\,i}$	refers to the curtailment price *c* at *dispatch interval i*
CVP	refers to *constraint* violation penalties

[16] *WESM Rules* Clause 3.6.1.3

4.4.2 The objective function may be comprised of a solution for only one *dispatch interval*, or a set of *dispatch intervals*.

4.4.3 *Market projections* shall employ a *security-constrained dynamic dispatch,* wherein the *economic gain* from trade for each execution of a *market projection* is maximized for the entire set of *dispatch intervals* in the covered study period of that *market projection*.

4.4.4 The *real time dispatch* shall employ a *security-constrained dynamic dispatch* and is solved per *dispatch interval.*

4.4.5 If there are no prices and schedules determined during the *real time dispatch,* then the results of the corresponding *hour ahead projection* shall be used for that *dispatch interval*[17].

4.5 Dispatch Constraints

4.5.1 The objective function in Section 4.4 of this *Market Manual* shall be subject to the following *constraints*.

a. System Constraints

   i. System power balance, including power balance during islanding operation
   ii. *Reserve region* requirements, including *ancillary services* cascading
   iii. *Reserve* provider capacity cap
   iv. AC power flow, including the *network* loss model and equipment power flow limits
   v. *HVDC* flow limit
   vi. Nodal *energy* balance *constraint*

b. Resource Constraints

   i. *Generator* resource *energy constraint*
   ii. *Load* resource *energy constraint*
   iii. *Reserve* resource *constraint*
      - *Reserve* capacity limit
      - Combined *reserve* ramping limit
   iv. Combined *energy* and *reserve* capacity limit
   v. Combined *energy* and *reserve* ramping
   vi. *Constraints* that pertain to the operational modes of *generators, loads* or similar facilities

c. Generic Constraints

   i. *Over-riding Constraints*
      - *Security Limit*
      - Transmission Limit
   ii. *Outage schedule*
   iii. *Contingency* list

[17] *WESM Rules* Clause 3.4.1.2

4.6 Tie-Breaking of Equivalent Offers[18]

4.6.1 In cases of two or more optimal solutions resulting from equivalent offers, the *market dispatch optimization model* shall pro-rate the schedule to the affected *Trading Participants* while observing equipment limitations based on the *generation offer*/*demand bid* block quantity.

4.6.2 In case of a tie between a *demand bid* and a *generator offer,* the *generation offer* shall be maximized to meet the *load* requirement.

4.7 Priority-Scheduling

4.7.1 When restricting *dispatch schedules* under *WESM Rules* Clause 3.6.1.7, the *market dispatch optimization model* shall consider the following hierarchy when a combination of the groups are to be restricted:[19]

a. *Market offers* of *scheduled generating units*
b. *Non-scheduled generating units*
c. *Priority dispatch generating units*
d. *Must dispatch generating units*

4.8 Constraint Violation Coefficients

4.8.1 The *constraint violation coefficients* shall correspond to *soft constraints* in the *market dispatch optimization model* and are associated with *constraint* violation prices[20].

4.8.2 Some *constraints* in the *market dispatch optimization model* shall be set up with one or more non negative violation variables and associated *constraint violation coefficients* to ensure that the *market dispatch optimization model* will always find a solution which satisfies all *constraints*, if such a solution exists. It shall also ensure that, if *constraints* are violated, the violation will occur in an appropriate priority order that takes account of the *system security* and *reliability* of the *power system* and the feasibility of the resulting *dispatch schedule*.

4.8.3 The following are the types of *constraint violation coefficients* incorporated in the *market dispatch optimization model*:

a. Deficit *reserve* for each *reserve category;*
b. *Nodal value of lost load;*
c. N-x contingency thermal *constraint*;
d. Under-generation;
e. Over-generation*; and*
f. Base case thermal *constraint*.
g. Self-scheduled generation *constraint*

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[18] See Appendix B for the sample application of the tie-breaking rules.
[19] *WESM Rules* Clauses 3.6.1.8
[20] *WESM Rules* Clauses 3.6.1.3 and 3.6.2

4.8.4 The *constraint violation coefficients* shall be set for:

a. *Market projections* and *dispatch schedules*, and
b. Market pricing reruns when the *market projections* and *dispatch schedules* have resulted in a non-zero violation variable.

4.8.5 The *constraint violation coefficients* shall be set for market pricing re-runs to ensure that the dispatch of all *network* elements, *loads*, and *generating units* produced by the market optimization *algorithm* are approximately the same as the original market *dispatch*. It shall also be set to ensure that the prices produced by the market optimization *algorithm* will be appropriate in all the circumstances for settlement purposes, taking into consideration the processes provided for in Section 5 of this *Market Manual*.

4.9 Outputs from the Market Dispatch Optimization Model

4.9.1 The optimization process shall produce the following outputs for the *market projections* and *real time dispatch:*

a. Cost of the solution or *economic gain*;
b. *Transmission line* flows;
c. Losses by each equipment and in aggregate;
d. *Dispatch schedules;*
e. *Market prices*
   i. *System marginal price;*
   ii. *Nodal energy dispatch prices;*
   iii. *Reserve* prices for each *reserve category* and *reserve region;* and
f. Non-zero *constraint violation variables.*

4.10 Locational Marginal Pricing

4.10.1 *Locational marginal pricing* shall reflect the benefit of supplying electricity or the cost of consuming electricity at that location under the specific system conditions that were considered in the *dispatch* scheduling process. Locational marginal prices shall consider the marginal price of *generation*, transmission losses and congestion, and is represented as follows:

$$LMP_j = \text{System Marginal Price} + \text{Marginal Cost of Losses} + \text{Marginal Cost of Congestion}$$

The *locational marginal pricing* formula is as follows:

$$LMP_j = \lambda + \left[\left(\frac{1}{TLF_j} - 1\right) * \lambda\right] + \sum \mu_o * a_{j,\,o}$$

Where:

LMP_j	refers to the locational marginal price at location *j*
λ	refers to the *system marginal price*
TLF_j	refers to the *transmission loss factor* at location *j*
u_o	refers to the price corresponding to *o^{th}* transmission *constraint*
$a_{j,\,o}$	refers to the sensitivity factor relating the contribution of *generation* at location *j* to the *energy* flow related to *constraint o*

4.10.2 *Transmission loss factors* shall be dynamically computed within the *market dispatch optimization model* to fully account for the dynamic change in the losses due to a change in *load* at the various nodes.

The *transmission loss factor* formula at location *j* is as follows:

$$\mathrm{TLF_j} = \frac{1}{1 - \frac{\partial \mathrm{P_{Loss}}}{\partial \mathrm{P_j}}}$$

Where:

TLF_j	refers to the *transmission loss factor* applied at location *j*
$\frac{\partial P_{Loss}}{\partial P_j}$	refers to the incremental change in loss due to the incremental change of power at location *j*

4.10.3 Congestion cost shall reflect the restriction imposed on *energy dispatches* due to the thermal limitations of affected transmission equipment. When a *market trading node* is affected by one or more congestions in the system, specific congestion costs shall be measured for such *market trading node* based on its sensitivity relative to the constrained equipment multiplied by the price corresponding to the transmission *constraint*. The sensitivity shall be measured based on power flow, wherein a *market trading node's* injection/withdrawal is evaluated if it affects the loading of the constrained equipment.

The congestion cost formula is as follows:

$$\text{Congestion Cost} = \sum \left[\mu_o * a_{j,o}\right]$$

Where:

μ_o	refers to the price corresponding to *o^{th}* transmission *constraint*
$a_{j,o}$	refers to the sensitivity factor relating the contribution of *generation* at location *j* to the *energy* flow related to *constraint o*

4.11 Reserves

4.11.1 *Reserve* and *energy dispatch schedules* shall be determined in a co-optimized manner in the *market dispatch optimization model*.[21]

4.11.2 The *Market Operator*, in consultation with the *System Operator*, shall determine an appropriate set of *reserve categories* to be traded in the *spot market* in conformance to the relevant provisions of the *Grid Code*[22].

4.11.3 The *reserve categories* shall correspond to mutually distinct responses to an increase or decrease in system frequency with different response timeframes. These shall be technology neutral to allow responses from any *facility* certified to be capable of providing the requisite response, and shall define responses for frequency regulation and *contingency reserves*.

4.11.4 The *Market Operator*, in consultation with the *System Operator*, shall determine an appropriate set of *reserve regions* that will be used for the purpose of setting *reserve requirements*, and determining *reserve prices* and *reserve cost recovery charges*[23].

4.11.5 The *reserve regions* shall initially consist of the Luzon, Visayas, and Mindanao grids.

4.11.6 The *reserve price* for each *reserve region* and *reserve category* shall be determined as the shadow price on the relevant *reserve requirement constraint* in the dispatch optimization for that *dispatch interval*[24].

4.12 Application of WESM Prices

4.12.1 In general, the nodal prices resulting from the *real time dispatch market run* as determined in Section 4.4.4, and, as applicable, Section 4.4.5, shall be used in the calculation of *settlement* prices except if there are non-zero constraint violation variable values or pricing error notices:

a) If there are one or more non-zero *constraint violation variable* values, then *automatic pricing re-run* prices in accordance with Section 5.2 shall apply; and
b) If there are pricing errors, prices from market pricing re-runs under Section 5.3 shall apply.

4.12.2 If conditions for extreme price separation due to *network congestion* exist, prices as determined in Section 4.12.1 shall be replaced in accordance with Section 6.

4.12.3 If conditions for price mitigation exist, prices as determined in Sections 4.12.1 and 4.12.2 shall be replaced in accordance with the methodology as approved by the *ERC*.

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[21] *WESM Rules* Clause 3.6
[22] *WESM Rules* Clause 3.3.4.2
[23] *WESM Rules* Clause 3.3.7.1
[24] *WESM Rules* Clauses 3.6.1.4 and 3.10.7

4.12.4 Notwithstanding Sections 4.12.1, 4.12.2 and 4.12.3, if the *dispatch interval* is under *market intervention or market suspension, administered prices* as determined under Section 7 shall apply.

SECTION 5 MARKET PRICING RE-RUNS

5.1 Scope

5.1.1 This section provides the *automatic pricing re-run*, which shall be performed automatically by the market system software of the *Market Operator* should the *market dispatch optimization model* result in one or more non-zero *constraint violation variable* values.[25]

5.1.2 This section also provides the market pricing re-run, which shall be performed by the *Market Operator* upon issuance of a *pricing error notice*, notwithstanding the application of an *automatic pricing re-run*.[26]

5.2 Automatic Pricing Re-Run

5.2.1 *Automatic pricing reruns* for *market projections* and *real time dispatch* shall ensure that the *energy* and *reserve prices* reflect the following:

a. marginal costs of supplying *energy* at each *node*;
b. marginal costs of supplying *reserve*;
c. shortage pricing when there is a shortage of supply at a *node* or regional level, as determined in accordance with Section 5.4; and
d. excess pricing when there is an excess of supply at a *node* or regional level, as determined in accordance with Section 5.4.

5.2.2 The *automatic pricing re-run* of the *market dispatch optimization model* shall determine the prices for *energy* and *reserves* with relaxed *constraints* and approximately the same *dispatch schedules.*

5.2.3 During the *automatic pricing re-run*, the soft *constraint* that was violated shall be relaxed corresponding to the resulting non-zero violation variable, including a very small value (delta) to allow the *market dispatch optimization model* to find a feasible price.

5.2.4 In case of over-generation and under-generation, the soft constraint shall be relaxed by a value (delta) to allow the *market dispatch optimization model* to find a feasible price. When the results of the *market dispatch optimization model* reflect a violation greater than delta, then the *automatic pricing re*-run shall reflect the shortage price for under-generation and excess pricing for over-generation.

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[25] *WESM Rules* Clause 3.6.7
[26] *WESM Rules* Clause 3.10.5

5.2.5 The delta shall be set as little as possible for each *constraint violation coefficient* so that the *automatic pricing re-run* is reflective of the most accurate price considering the original *dispatch schedules*.

5.2.6 The following table shows each type of *constraints* with their corresponding *constraint* relaxation formulas during pricing re-runs:

Soft Constraint	Violation	Constraint Relaxation during Pricing Re-Run	Re-run Price[27]
Thermal Base Case	x	x + delta	EDP AND RP
Transmission Group	x	x + delta	EDP AND RP
Self-Scheduled Generation *Constraint*	x	x + delta	EDP AND RP
System Energy Balance	x	delta	Excess Price if Over-generation Shortage Price if Under-generation
Nodal Value of Lost Load or Nodal Energy Balance	x	x + delta	EDP AND RP
Thermal Contingency	x	x + delta	EDP AND RP
Reserve Requirement	x	x + delta	EDP AND RP

5.2.7 The *market projections* and *real time dispatch runs* shall be reflective of prices determined from *automatic pricing re-runs.*

5.3 Market Pricing Re-Run to address Pricing Errors

5.3.1 In the event where no *real time dispatch* prices can be determined or communicated as specified by the *timetable* or the calculated prices are believed to be in error due to erroneous, inconsistent, or inappropriate input data, notwithstanding the application of *automatic pricing re-run*, the *Market Operator* shall issue a *pricing error notice* and perform a market pricing re-run.[28]

5.3.2 The *Market Operator* shall perform the market pricing re-run using the same set of input data used in the original *real time dispatch market run* and the appropriate solution while taking into consideration the applicable solutions for the various causes of erroneous, inconsistent and inappropriate input data.

[27] EDP refers to *nodal energy dispatch price;* and RP refers to *reserve price*
[28] *WESM Rules* Clause 3.10.5

5.4 Shortage and Excess Prices

5.4.1 In the event of under-generation, the shortage price shall be determined as the offer price cap.

5.4.2 In the event of over-generation, the excess price shall be determined as the offer price floor.

SECTION 6 PRICE SUBSTITUTION METHODOLOGY DUE TO CONGESTION

6.1 Scope

6.1.1 This section provides the price substitution methodology, which shall be implemented by the *Market Operator* to address the undesirable market pricing situations that arise from the effects of *network congestion* in the *power system*, in particular, the occurrence of extreme nodal price separation[29].

6.2 Criteria for Determining Extreme Nodal Price Separation Arising Due To Network Congestion

6.2.1 If a *dispatch interval* is reflective of extreme nodal price separation due to *network congestion*, then prices shall be substituted for the affected *generators* and *customers*.

6.2.2 The following *constraints* shall not be considered as *network congestion*:

a. *Constraint* indicated in the *market run* is caused by erroneous input data.
b. Localized *constraint,* such as but not limited to, *constraint* on a radially-connected line or load-end transformer, which is the source of the *load* connected to it or of the step-up transformer in a generating plant.

6.2.3 A *dispatch interval* shall be identified to be reflective of extreme nodal price separation through the use of a trigger factor, which is formulated as follows:

$$\text{Price Trigger Factor}_i = \frac{\dfrac{\sum_{j \in J}\left[\text{EDS}_{j,i} * \left(\text{EDP}_{j,i} - \text{NWAP}_i\right)^2\right]}{\sum_{j \in J}\left(\text{EDS}_{j,i}\right)}}{\text{NWAP}_i}$$

Where:

J	refers to the set of all resources
$EDS_{j,i}$	refers to the *energy dispatch schedule* of resource *j* at *dispatch interval i*

[29] *WESM Rules* Clause 3.12.7

$EDP_{j,i}$	refers to the *nodal energy dispatch price* of resource *j* at *dispatch interval i*
$NWAP_i$	refers to the weighted average price of all resources and computed as:

$$NWAP_i = \frac{\sum_{j \in J}\left(EDP_{j,\,i} * EDS_{j,\,i}\right)}{\sum_{j \in J}\left(EDS_{j,\,i}\right)}$$

6.2.4 The price substitution methodology set forth in this section shall apply to a *dispatch interval* when the trigger factor reaches the threshold of 1.40.

6.3 Price Substitution Methodology for Generator Energy Prices

6.3.1 An *unconstrained solution* shall be used for determining the generator energy prices.

6.3.2 *Constrained-on generators* shall be paid at their offer price, while all the other *generating units* shall be paid at the *unconstrained solution's* marginal price.

6.4 Price Substitution Methodology for Customer Energy Prices

6.4.1 All *loads* shall have the same price and shall be calculated as follows:

$$SEDP_{b,\,i} = \frac{\sum_{k \in K}\left(SEDP_{k,\,i} * EDS_{k,\,i}\right)}{\sum_{b \in B}\left(EDS_{b,\,i}\right)}$$

Where:

$SEDP_{b,i}$	refers to the substitute *nodal energy dispatch price* of *customer b* at *dispatch interval i*
$SEDP_{k,i}$	refers to the substitute *nodal energy dispatch price* of *generator k* at *dispatch interval i*
$EDS_{k,i}$	refers to the *energy dispatch schedule* of *generator k* in the *constrained solution* at *dispatch interval i*
$EDS_{b,i}$	refers to the *energy dispatch schedule* of *customer b* at *dispatch interval i*

6.4.2 In cases where the *HVDC* is on *outage* or there is no interconnection between the Luzon, Visayas, and Mindanao regions, Section 6.4.1 will apply only to the region/s with congestion.

6.5 Price Substitution Methodology for Reserve Prices

6.5.1 Aside from normalizing the *energy* prices due to the congestion, the price substitution methodology shall also consider the impact of the extreme nodal price separation on the resulting *reserve prices*.

6.5.2 In cases where price substitution methodology is applied, the *reserve price* for a certain *reserve category* in a *reserve region* shall be calculated as the sum of the *constrained solution*'s marginal *reserve offer* price and the opportunity cost calculated based on the *unconstrained solution*. It shall be calculated as follows:

$$SRP_{j,\,r,\,a,\,i} = MROP_{CONS\text{-}r,\,a,\,i} + OppCost_{UNCD\text{-}r,\,a,\,i}$$

Where:

$SRP_{j,\,r,\,a,\,i}$	refers to the substitute *reserve price* of *reserve category r* in *reserve region a* for *dispatch interval i*
$MROP_{CONS\text{-}r,\,a,\,i}$	refers to the marginal *reserve offer* price in *reserve category r* in *reserve region a* for *dispatch interval i* during the *constrained solution*
$OppCost_{UNCD\text{-}r,\,a,\,i}$	refers to the opportunity cost based on the *unconstrained solution* in *reserve category r* in *reserve region a* for *dispatch interval i*

SECTION 7 ADMINISTERED PRICES

7.1 Scope

7.1.1 This section provides the administered price determination methodology, which shall be implemented by the *Market Operator* to impose *administered prices* on *dispatch intervals* under *market suspension* or *market intervention*.[30]

7.1.2 The *administered price* shall be established by the *Market Operator* in accordance with the following *guiding principles*:

a. The *administered price* shall be fair and reasonable to both the suppliers and consumers of electricity.
b. *Administered prices* shall be determined and shall replace *market prices* for *energy, i.e. energy administered prices* shall replace the *nodal energy dispatch prices,* and *reserves, i.e. reserve administered prices* shall replace the *reserve prices*.
c. The process for determining the *administered price* shall be transparent to the *Trading Participants* and administratively simple to implement.
d. The process for determining the *administered price* shall be based on the market information available prior to *market intervention* or *market suspension.*
e. The *administered price* shall be applied in the region where the *market suspension* or *market intervention* is declared. For this purpose, the regions are Luzon, Visayas and Mindanao.
f. Where *market suspension* or *market intervention* is declared in an island grid ("grid islanding"), the *administered prices* shall be applied only to the resources in the island grid where the *market suspension* or *market intervention* was declared.

[30] *WESM Rules* Clause 6.2.3

g. The *administered price* will apply only to transactions above the declared *bilateral contract* quantities.

7.2 Generator Energy Administered Price

7.2.1 For each *generator* resource, the *energy administered price* shall be computed as the *dispatch schedule*-weighted average of the *nodal energy dispatch prices* of the four most recent similar *trading day* and similar *dispatch intervals* that have not been administered.

7.2.2 For each *generator* resource k, the *energy administered price* is computed as follows:

$$EAP_{k,D,i} = \frac{\sum_{d=D-n}^{D-4}\left(NEDP_{k,d,i} * EDS_{k,d,i}\right)}{\sum_{d=D-n}^{D-4} EDS_{k,d,i}}$$

Where:

$EAP_{k,D,i}$	refers to the *energy administered price* for *generator* resource *k* at *dispatch interval i* within *trading day D*
$EDP_{k,d,i}$	refers to the *nodal energy dispatch price* for *generator* resource *k* for *dispatch interval i* within *trading day d*
$EDS_{k,d,i}$	refers to the *energy dispatch schedule* for *generator* resource *k* at *dispatch interval i* within *trading day d*
D	refers to the current *trading day*
$d = D - n$	refers to the n^{th} most recent non-administered similar *trading day* of *D*

7.2.3 Similar *trading days* refer to each day of the week (i.e., Sunday, Monday, Tuesday, Wednesday, Thursday, Friday, Saturday) while similar *dispatch intervals* refer to the same five (5) minute period within the same *settlement interval*.

7.2.4 In case the *energy dispatch schedule* for a *generator* resource at a similar *trading day* and similar *dispatch interval* is negative, the *energy dispatch schedule* for that similar *trading day* and similar *dispatch interval* shall be set to zero during the calculation of the *energy administered price* for that *generator* resource.

7.2.5 If no *energy administered price* can be determined for a *generator* resource because the *generator* resource had no *energy dispatch schedule* for the previous four (4) similar *trading days* and similar *dispatch intervals*, the *energy administered price* for that *generator* resource shall be determined as follows:

a. The *nodal energy dispatch price* of the immediately preceding similar *trading day*, similar *dispatch interval*, non-administered price, with positive *energy dispatch schedule* within one (1) year prior to the *trading day* and *dispatch interval* being considered shall be set as the *energy administered price* of that *generator* resource; and

b. In case a *generator* resource does not have a positive *energy dispatch schedule* during similar *trading days* and similar *dispatch intervals* that were not administered for the past year, the *energy administered price* for that *generator* resource shall be computed by obtaining the simple average of the *nodal energy dispatch prices* of four (4) immediately preceding similar *trading day*, similar *dispatch intervals* that have not been administered. This is set out in the following formula:

$$EAP_{k,\,D,\,i} = \frac{\sum_{d=D-n}^{D-4} EDP_{k,\,d,\,i}}{4}$$

Where:

$EAP_{k, D, i}$	refers to the *energy administered price* for *generator* resource *k* for *dispatch interval i* within *trading day D*
$EDP_{k, d, i}$	refers to the *nodal energy dispatch price* for *generator* resource *k* for *dispatch interval i* within *trading day d*
D	refers to the *trading day* with *dispatch interval* under *market intervention* or *market suspension*
$d = D - n$	refers to the n^{th} most recent non-administered similar *trading day* and similar *dispatch interval*

c. In case a *generator* resource does not have *nodal energy dispatch prices* from four (4) immediately preceding similar *trading day*, similar *dispatch intervals* that have not been administered, the *energy administered price* for that *generator* resource shall be calculated as follows:

$$EAP_{k,\,D,\,i} = \frac{\sum_{k' \in K_i, k' \neq k} \left(EAP_{k',D,i} \; * \; EDS_{k',D,i} \right)}{\sum_{k' \in K_i, k' \neq k} EDS_{k',D,i}}$$

Where:

$EAP_{k, D, i}$	refers to the *energy administered price* for *generator* resource *k* for *dispatch interval i* within *trading day D*
$EAP_{k', D, i}$	refers to the *energy administered price* for *generator* resource *k'* for *dispatch interval i* within *trading day D*
$EDS_{k',D,i}$	refers to the *energy dispatch schedule* for *generator* resource *k'* at *dispatch interval i* within *trading day d*
D	refers to the *trading day* with *dispatch interval* under *market intervention* or *market suspension*
K_i	refers to the set of *generator* resources with positive *energy* dispatch quantities at *dispatch interval i*

7.3 Customer Energy Administered Price

7.3.1 The *energy administered price* for all *customer* resources shall be calculated as follows:

$$EAP_{b,i}=\frac{\sum_{k\in K_i}\left(EAP_{k,i} * EDS_{k,i}\right)}{\sum_{b\in B} EDS_{b,i}}$$

Where:

$EAP_{b,i}$	refers to the *energy administered price* for customer resource *b* for *dispatch interval i*
$EAP_{k,i}$	refers to the *energy administered price* for *generator* resource *k* at *dispatch interval i*
$EDS_{k,i}$	refers to the *energy dispatch schedule* for *generator* resource *k* at *dispatch interval i*
$EDS_{b,i}$	refers to the *energy dispatch schedule* for *customer* resource *b* at *dispatch interval i*
K_i	refers to the set of *generator* resources with positive *energy* dispatch quantities at *dispatch interval i*
B	refers to the set of all *customer* resources

7.3.2 In case only one region is under *market suspension* or *market intervention* and the said region is importing power from the other region, the *energy administered price* for all customer resources within the region under *market suspension* or *market intervention* shall be calculated as follows:

$$EAP_{b,\, i}=\frac{\sum_{k\in K_i}\left(EAP_{k,\, i} * EDS_{k,\, i}\right)+\left(EDS_{HVDC,\, i} * GWAP_{NAR,\, i}\right)}{\sum_{b\in B_i} EDS_{b,\, i}}$$

Where:

$EAP_{b,i}$	refers to the *energy administered price* for customer resource *b* for *dispatch interval i*
$EAP_{k,i}$	refers to the *energy administered price* for *generator* resource *k* for *dispatch interval i*
$EDS_{k,i}$	refers to the *energy dispatch schedule* for *generator* resource *k* for *dispatch interval i*
$EDS_{HVDC,i}$	refers to the *energy dispatch schedule* of the *HVDC* interconnection for *dispatch interval i*
$GWAP_{NAR,i}$	refers to the generator weighted average price in the non-administered region using *energy dispatch schedule* for *dispatch interval i*
$EDS_{b,i}$	refers to the *energy dispatch schedule* for *customer* resource *b* at *dispatch interval i*
K_i	refers to the set of *generator* resources in the region under *market suspension* or *market intervention* with positive *energy dispatch schedule* for *dispatch interval i*
B_i	refers to the set of all *customer* resources in the region under *market suspension* or *market intervention* at *dispatch interval i*

7.3.3 In case only one region is under *market suspension* or *market intervention* and the said region is exporting power to the other region, the *energy administered price* for all *customer* resources within the region under *market suspension* or *market intervention* shall be calculated as follows:

$$EAP_{b,\,i}=\frac{\sum_{k\in K_i}\left(EAP_{k,\,i} * EDS_{k,\,i}\right) - \left(EDS_{HVDC,\,i} * GWAEAP_i\right)}{\sum_{b\in B_i} EDS_{b,\,i}}$$

Where:

$EAP_{b,i}$	refers to the *energy administered price* for *customer* resource *b* for *dispatch interval i*
$EAP_{k,i}$	refers to the *energy administered price* for *generator* resource *k* for *dispatch interval i*
$EDS_{k,i}$	refers to the *energy dispatch schedule* for *generator* resource *k* at *dispatch interval i*
$EDS_{HVDC,i}$	refers to the *energy dispatch schedule* of the *HVDC* interconnection at *dispatch interval i*
$GWAEAP_i$	refers to the generator weighted average *energy administered price* using *energy dispatch schedule* for *dispatch interval i*
$EDS_{b,i}$	refers to the *energy dispatch schedule* (in MW) for *customer* resource *b* for *dispatch interval i*
K_i	refers to the set of *generator* resources in the region under *market suspension* or *market intervention* with positive *energy dispatch schedule* for *dispatch interval i*
B_i	refers to the set of all *customer* resources in the region under *market suspension* or *market intervention* for *dispatch interval i*

7.3.4 In case only one region is under *market suspension* or *market intervention* and the said region is exporting power to the other region and the *nodal energy dispatch prices* in the region that is not under *market suspension* or *market intervention* were determined in accordance with *WESM Rules* Clause 3.6, the *nodal energy dispatch prices* for the *customer* resources within the region that is not under *market suspension* or *market intervention* shall be adjusted by adding the following:

$$NARAPA_{b\text{-}NAR,\,i}=\frac{EDS_{HVDC,\,i} * \left(GWAP_{NAR,\,i} - WAGEAP_i\right)}{\sum_{b\in B\text{-}NAR_i} EDS_{b\text{-}NAR,\,i}}$$

Where:

$NARAPA_{b\text{-}NAR,i}$	refers to the non-administered region administered price adjustment for a *customer* resource within the non-administered region for *dispatch interval i*
$EDS_{HVDC,i}$	refers to the *energy dispatch schedule* of the *HVDC* interconnection for *dispatch interval i*
$GWAP_{NAR,i}$	refers to the generator weighted average price at the non-administered region using *energy dispatch schedule* for *dispatch interval i*

$WAGEAP_i$	refers to the generator weighted average *energy administered price* using *energy dispatch schedule* for *dispatch interval i*
$EDS_{b\text{-}NAR,i}$	refers to the *energy dispatch schedule* of a *customer* resource within the non-administered region for *dispatch interval i*
$B\text{-}NAR_i$	refers to the set of all *customer* resources within the non-administered region for *dispatch interval i*
b-NAR	refers to a *customer* resource within the non-administered region

7.4 Generator Reserve Administered Price

7.4.1 For each *generator* resource, the *reserve administered price* for each *reserve category* shall be computed as the *dispatch schedule*-weighted average of the *reserve prices* for each *reserve category* of the four (4) most recent similar *trading day* and similar *dispatch intervals* that have not been administered, as follows:

$$RAP_{k,r,D,i}=\frac{\sum_{d=D-n}^{D-4}\left(RDP_{k,r,d,i} * RDS_{k,r,d,i}\right)}{\sum_{d=D-n}^{D-4} RDS_{k,r,d,i}}$$

Where:

$RAP_{k,r,D,i}$	refers to the *reserve administered price* for *generator* resource *k* for *reserve category r* at *dispatch interval i* within *trading day D*
$RDP_{k,r,d,I}$	refers to the *reserve dispatch price* for *generator* resource *k* for *reserve category r* at *dispatch interval i* within *trading* day *d*
$RDS_{k,r,d,i}$	refers to the *reserve dispatch schedule* for *generator* resource *k* for *reserve category r* at *dispatch interval i* within *trading day d*
D	refers to the *trading day* with *dispatch interval* under *market intervention* or *market suspension*
D – n	refers to the n^{th} most recent non-administered similar *trading day* and similar *dispatch interval*

7.4.2 For each *generator* resource, the *reserve dispatch schedule* shall be set to the *reserve* schedules determined by the *System Operator* for the *dispatch interval* under *market suspension* or *market intervention*.

7.4.3 Similar *trading days* refer to each day of the week (i.e., Sunday, Monday, Tuesday, Wednesday, Thursday, Friday, Saturday) while similar *dispatch intervals* refer to the same five (5) minute period within the same *settlement interval.*

7.4.4 If no *reserve administered price* can be determined for a *generator* resource because the *generator* resource had no *reserve dispatch schedule* for the previous four (4) similar *trading days* and similar *dispatch intervals*, the *reserve administered price* for that *generator* resource shall be determined as follows:

a. The *reserve price* of the immediately preceding similar *trading day*, similar *dispatch interval*, non-administered price, with *reserve dispatch schedule* within one (1) year prior to the *trading day* and *dispatch interval* being considered shall be set as the *reserve administered price* of that *generator* resource; and

b. In case a *generator* resource does not have a *reserve dispatch schedule* for a *reserve category* during similar *trading days* and similar *dispatch intervals* that were not administered for the past year, the *reserve administered price* for that *generator* resource for that *reserve category* shall be computed by obtaining the simple average of the *reserve prices* for that *reserve category* for the *reserve region* which includes the *generator resource* of four (4) immediately preceding similar *trading day*, similar *dispatch intervals* that have not been administered. This is as set out in the following formula:

$$RAP_{k,\,r,\,D,\,i} = \frac{\sum_{d=D-n}^{D-4} RDP_{k,\,r,\,d,\,i}}{4}$$

Where:

$RAP_{k,r,D,i}$	refers to the *reserve administered price* for *reserve category r* for the *reserve region* which includes *generator* resource *k* for *dispatch interval i* within *trading day D*
$RDP_{k,r,d,i}$	refers to the *reserve price* for *generator* resource *k* for *reserve category r* for *dispatch interval i* within *trading day d*
D	refers to the *trading day* with *dispatch interval* under *market intervention* or *market suspension*
D-n	refers to the n^{th} most recent non-administered similar *trading day* and similar *dispatch interval*

7.4.5 No *reserve administered prices* are calculated for *customers* within the region under *market suspension* or *market intervention*.

SECTION 8 BILLING AND SETTLEMENT

8.1 Scope

8.1.1 This section provides the formula used to determine the *trading* and *settlement amounts* for *energy* and *reserves* for each *Trading Participant*.[31]

8.1.2 This section also provides the formula to determine the costs of *reserves* to be recovered through the settlement amounts calculated.[32]

8.1.3 This section also provides the provision of additional compensation for *Trading Participants* affected by *market suspension or market intervention* or are designated as *must-run units.*

[31] *WESM Rules* Clause 3.13
[32] *WESM Rules* Clause 3.3.5.2

8.2 Settlement Prices

8.2.1 Energy Settlement Price[33]

Energy settlement prices shall be determined for every *settlement interval*[34] and are calculated as follows:

a. For a *generator,* it is the *generator dispatch schedule*-weighted average of the *nodal energy dispatch prices* for the set of *dispatch intervals* corresponding to that *settlement interval* determined for that *generator market trading node*, as provided in the following formula:

$$ESP_{k,h} = \frac{\sum_{i \in n}\left(EDP_{k,h,i} * EDS_{k,h,i}\right)}{\sum_{i \in N} EDS_{k,h,i}}$$

However, if:

$$\sum_{i \in N} EDS_{k,h,i} = 0$$

Then:

$$ESP_{k,h} = \frac{\sum_{i \in N} EDP_{k,h,i}}{n}$$

Where:

n	refers to the number of *dispatch intervals* at settlement interval *h*
$ESP_{k,h}$	refers to the *energy settlement price* of *generator* resource *k* (*generator* or *load*) at *settlement interval h*
$EDP_{k,h,i}$	refers to the *nodal energy dispatch price* for *generator* resource *k* at *dispatch interval i* of *settlement interval h*
$EDS_{k,h,i}$	refers to the *energy dispatch schedule* for *generator* resource *k* at *dispatch interval i* of *settlement interval h*

b. For *customers*, it is the *customer dispatch schedule*-weighted average of the *nodal energy dispatch prices* for the set of *dispatch intervals* corresponding to that *settlement interval* determined for that *customer market trading node*, as provided in the following formula:

$$ESP_{b,h} = \frac{\sum_{i \in n}\left(EDP_{b,h,i} * EDS_{b,h,i}\right)}{\sum_{i \in N} EDS_{b,h,i}}$$

[33] *WESM Rules* Clause 3.10.6
[34] *WESM Rules* Clause 3.4.2

However, if:

$$\sum_{i \in N} EDS_{b,h,i} = 0$$

Then:

$$ESP_{b,h} = \frac{\sum_{i \in N} EDP_{b,h,i}}{n}$$

Where:

n	refers to the number of *dispatch intervals* at *settlement interval h*
$ESP_{b,h}$	refers to the *energy settlement price* of *customer* resource *b* (*generator* or *load*) at *settlement interval h*
$EDP_{b,h,i}$	refers to the *nodal energy dispatch price* for *customer* resource *b* at *dispatch interval i* of *settlement interval h*
$EDS_{b,h,i}$	refers to the *energy dispatch schedule* for *customer* resource *b* at *dispatch interval i* of *settlement interval h*.

c. For *customers* that have been approved by the *ERC* to use zonal pricing, the zonal energy settlement price is the *customer dispatch schedule*-weighted average of the *ex-ante zonal energy prices* for the set of *dispatch intervals* within that *settlement interval* determined for that *customer market trading node*, as provided in the following formula:

i. Zonal Energy Price

$$ZEP_{b,h,i} = \frac{\sum_{b \in B_z} \left(EDP_{b,h,i} * EDS_{b,h,i}\right)}{\sum_{b \in B_z} EDS_{b,h,i}}$$

However, if:

$$\sum_{b \in B_z} EDS_{b,h,i} = 0$$

Then:

$$ZEP_{b,h,i} = \frac{\sum_{b \in B_z} EDP_{b,h,i}}{n_z}$$

Where:

n_z	refers to the number of *customer resources* within *customer pricing zone z*

$ZEP_{b,h,i}$	refers to the *zonal energy price* for *customer* resource *b* at *dispatch interval i* of *settlement interval h*
$EDP_{b,h,i}$	refers to the *nodal energy dispatch price* for *customer* resource *b* at *dispatch interval i* of *settlement interval h*
$EDS_{b,h,i}$	refers to the *energy dispatch schedule* for *customer* resource *b* at *dispatch interval i* of *settlement interval h*.
B_z	set of all *customer resources* within *customer pricing zone z*

ii. Energy Settlement Price

$$ESP_{b,h} = \frac{\sum_{i \in n} \left(ZEP_{b,h,i} * EDS_{b,h,i} \right)}{\sum_{i \in N} EDS_{b,h,i}}$$

However, if:

$$\sum_{i \in N} EDS_{b,h,i} = 0$$

Then:

$$ESP_{b,h} = \frac{\sum_{i \in N} ZEP_{b,h,i}}{n}$$

Where:

n	refers to the number of *dispatch intervals* at *settlement interval h*
$ESP_{b,h}$	refers to the *energy settlement price* of *customer* resource *b* (*generator* or *load*) at *settlement interval h*
$ZEP_{b,h,i}$	refers to the *zonal energy price* for *customer* resource *b* at *dispatch interval i* of *settlement interval h*
$EDS_{b,h,i}$	refers to the *energy dispatch schedule* for *customer* resource *b* at *dispatch interval i* of *settlement interval h*.

8.2.2 Reserve Settlement Price[35]

a. When applicable, the *reserve settlement price* of an *Ancillary Services Provider* for each *reserve region* and *reserve category* in each *settlement interval* shall be determined as the *dispatch schedule*-weighted average of the corresponding *reserve prices* for that *reserve category* for that *Ancillary Services Provider*, as provided in the following formula:

$$RSP_{j,\ r,\ a,\ h} = \frac{\sum_{i \in n} \left(RDP_{j,\ r,\ a,\ i} * RDS_{j,\ r,\ a,\ i} \right)}{\sum_{i \in N} RDS_{j,\ r,\ a,\ i}}$$

[35] *WESM Rules* Clause 3.10.7

However, if:

$$\sum_{i \in N} RDS_{j,\ r,\ a,\ i} = 0$$

Then:

$$RSP_{j,\ r,\ a,\ h} = \frac{\sum_{i \in N} RDP_{j,\ r,\ a,\ i}}{n}$$

Where:

n	refers to the number of *dispatch intervals* at *settlement interval h*
$RSP_{j,\ r,\ a,\ h}$	refers to the *reserve settlement price* of resource *j* for *reserve category r* and *reserve region a* at *settlement interval h*
$RDP_{j,\ r,\ a,\ i}$	refers to the *reserve dispatch price* for resource *j* for *reserve category r* and *reserve region a* at *dispatch interval i*
$RDS_{j,\ r,\ a,\ i}$	refers to the *reserve dispatch schedule* for resource *j* for *reserve category r* and *reserve region a* at *dispatch interval i*

8.3 Reserve Cost Recovery

8.3.1 Cost Recovery for Regulation Service

a. The hourly reserve cost attributed to the regulation service shall be recovered from all resources (*generators* or *loads*) by pro-rating the regulation *reserve* cost based on their respective *metered quantities*.

$$RRCost_{j,\ REG\text{-}r,\ a,\ h} = \frac{RTA_{REG\text{-}r,\ a,\ h}}{\sum_{j \in J} MQ_{j,\ a,\ h}} * MQ_{j,\ a,\ h}$$

Where:

$RRCost_{j,\ REG\text{-}r,\ a,\ h}$	refers to the regulation *reserve cost* to be paid by resource j for regulation reserve category REG-r in *reserve region a* at settlement interval *h*
$RTA_{REG\text{-}r,\ a,\ h}$	refers to the *reserve trading amount* for the regulation service in *reserve region a* for regulation reserve category REG-r at settlement interval *h*
$MQ_{j,\ a,\ h}$	refers to the actual quantity of *energy* delivered or consumed by resource *j* based on a valid *metering point(s)* in *reserve region a* at *settlement interval h*

8.3.2 Cost Recovery for Contingency Service

a. The *reserve* costs for contingency service shall be allocated among *generators* using a "runway model".[36]

b. The *reserve* cost attributable to a *generator* is calculated using the following formula:

$$CRCost_{k,\,r,\,a,\,h} = RTA_{r,\,a,\,h} * \sum_{p \in P} \left[\frac{GA_{p,\,r,\,a,\,h} * SQTY_{k,\,p,\,r,\,a,\,h}}{\sum_{j \in J} RDS_{j,\,r,\,a,\,h}} \right]$$

Where:

$CRCost_{k,\,r,\,a,\,h}$	refers to the *reserve* cost to be paid by *generator k* in *reserve region a* for reserve category r at *settlement interval h*
$RTA_{r,\,a,\,h}$	refers to contingency *reserve trading amount* in *reserve region a* for reserve category r at *settlement interval h*
$SQTY_{k,\,p,\,r,\,a,\,h}$	refers to the MW quantity shared by *generator k* in the common block *p* for reserve category r in *reserve region a* at *settlement interval h*
$RDS_{j,\,r,\,a,\,h}$	refers to the total *reserve dispatch schedule* of resource *j* in *reserve region a* for *reserve category* r at *settlement interval h*
$GA_{p,\,r,\,a,\,h}$	refers to the generator allocation per common block *p* in *reserve region a* at *settlement interval h.* It is the inverse of the number of generating units in a common block *p* as represented by the following formula:

$$GA_{p,\,r,\,a,\,h} = \frac{1}{\text{No. of Generators sharing in block p in reserve area a for } \textit{reserve category} \text{ r at settlement interval h}}$$

8.4 Trading Amounts

8.4.1 Energy Trading Amount

a. The *energy settlement quantity* for any *market trading node* in any *settlement interval* shall be determined by the *Market Operator* as the *metered quantity* as determined under *WESM Rules* clause 3.13.6 and adjusted for *bilateral contracts* under *WESM Rules* clause 3.13.7.

b. The *energy trading amount* for a *market trading node* and *settlement interval* shall be determined as the *energy settlement price* for that *node* in that *settlement interval*

[36] See Appendix C for explanatory examples on the runway model.

multiplied by the *energy settlement quantity*, in MWh, for that *node* in the same *settlement interval,*[37] and is calculated for generators and customers as follows:

i. Generators

$$ETA_{k,h} = \left(ESP_{k,h} * GESQ_{k,h}\right) - \sum_{b \in B}\left(ESP_{k,b,h} * BCQ_{k,b,h}\right)$$

Where:

B	refers to the total number of counter-party resources
$ETA_{k,h}$	refers to the *energy trading amount* of resource *k* at *settlement interval h*
$ESP_{k,h}$	refers to the *energy settlement price* of *generator* resource *k* at *settlement interval h*
$GESQ_{k,h}$	refers to the gross *energy settlement quantity* for *generator* resource *k* at *settlement interval h*
$ESP_{k,b,h}$	refers to the reference *energy settlement price* for the *bilateral contract quantity* between *generator* resource *k* and *load* resource *b* at *settlement interval h* (default is *generator* ESP)
$BCQ_{k,b,h}$	refers to the *bilateral contract quantity* for *generator* resource *k* to counterparty *load* resource *b* at *settlement interval h*

ii. Customers/Buyers

$$ETA_{b,h} = \left(ESP_{b,h} * GESQ_{b,h}\right) - \sum_{k \in K}\left(ESP_{b,k,h} * BCQ_{b,k,h}\right)$$

Where:

K	refers to the total number of *generator* resources that resource *b* has a contracted with at *settlement interval h*
$ETA_{b,h}$	refers to the *energy trading amount* of *load* resource *b* at *settlement interval h*
$ESP_{b,h}$	refers to the *energy settlement price* of *load* resource *b* at *settlement interval h*
$GESQ_{b,h}$	refers to the gross *energy settlement quantity* for *load* resource *b* at *settlement interval h*
$ESP_{b,k,h}$	refers to the reference *energy settlement price* for the *bilateral contract quantity* between *generator* resource *k* and *load* resource *b* at *settlement interval h* (default is *generator* ESP)
$BCQ_{b,k,h}$	refers to the *bilateral contract quantity* for *load* resource *b* to counter-party *generator* resource *k* at *settlement interval h*

[37] *WESM Rules* Clause 3.13.8

8.4.2 Reserve Trading Amount

a. The gross *reserve settlement quantity* for any *market trading node* in any *settlement interval* shall be determined by the *Market Operator* as the average of the *reserve* schedule for each *facility*.[38]

$$GRSQ_{j,\,r,\,a,\,h} = \frac{\sum_{i \in N} RDS_{j,\,r,\,a,\,i}}{n}$$

Where:

$GRSQ_{j, r, a, h}$	refers to the gross *reserve settlement quantity* of resource *j* for *reserve category r* and *reserve region a* at *settlement interval h*
$RDS_{j, r, a, i}$	refers to the *reserve dispatch schedule* for resource *j* for *reserve category r* and *reserve region a* at *dispatch interval i*
n	refers to the number of *dispatch intervals* at *settlement interval h*

b. The *reserve settlement quantity* for any *market trading node* in any *settlement interval* shall be determined by the *Market Operator* as the gross *reserve settlement quantity* less *reserve* contracted quantities.[39]

$$RSQ_{j,\,r,\,a,\,h} = \left(GRSQ_{j,\,r,\,a,\,h} - RBCQ_{j,\,r,\,a,\,h}\right)$$

Where:

$RSQ_{j, r, a, h}$	refers to the *reserve settlement quantity* of resource *j* for *reserve category r* and *reserve region a* at *settlement interval h*
$GRSQ_{j, r, a, h}$	refers to the gross *reserve settlement quantity* of resource *j* for *reserve category r* and *reserve region a* at *settlement interval h*
$RBCQ_{j, r, a, h}$	refers to the *bilateral contract quantity* for resource *j* for *reserve category r* and *reserve region a* at *settlement interval h*

c. For *settlement* purposes, the *reserve trading amount* for each *Trading Participant* who supplies reserve to a particular *reserve region* in a *settlement interval* shall be determined as the *reserve settlement price* for that *reserve region* in that *settlement interval* multiplied by the *reserve settlement quantity* for that *Trading Participant* in that *reserve region* for that *settlement interval.*[40]

$$RTA_{j,\,r,\,a,\,h} = RSP_{j,\,r,\,a,\,h} * RSQ_{j,\,r,\,a,\,h}$$

Where:

[38] *WESM Rules* Clause 3.13.5
[39] *WESM Rules* Clause 3.13.5
[40] *WESM Rules* Clause 3.13.9

$RTA_{j,r,a,h}$	refers to the *reserve trading amount* of resource *j* for *reserve category r* and *reserve region a* at *settlement interval h*
$RSP_{j,r,a,h}$	refers to the *reserve settlement price* of resource *j* for *reserve category r* and *reserve region a* at *settlement interval h*
$RSQ_{j,r,a,h}$	refers to the *reserve settlement quantity* of resource *j* for *reserve category r* and *reserve region a* at *settlement interval h*

8.4.3 Aggregate Trading Amount

a. The aggregate *trading amount* for a *Trading Participant* for a *settlement interval* is determined as follows:[41]

i. *Energy trading amount,* which may be positive or negative for any *Trading Participant;* plus
ii. *Reserve trading amount* for each *reserve region,* which will always be positive for both *Generation Companies* and *Customers;* plus
iii. Upon approval of the trading of financial *transmission rights*, the *transmission right* trading amounts for each *transmission right* held by the *WESM Participant*; less
iv. The *reserve cost recovery charge* determined for that *Trading Participant* with respect to any *reserve cost recovery zone*, which will be positive for any *Trading Participant.*

b. This is provided in the following formula:

$$\mathrm{TA}_{\mathrm{p,h}} = \sum_{\mathrm{j} \in \mathrm{J_p}} \mathrm{ETA}_{\mathrm{j,h}} + \sum_{\mathrm{j} \in \mathrm{J_p}} \sum_{\mathrm{r} \in \mathrm{R_j}} \mathrm{RTA}_{\mathrm{j,r,a,h}} + \sum_{\mathrm{t} \in \mathrm{T_p}} \mathrm{TRTA}_{\mathrm{t,h}} - \sum_{\mathrm{j} \in \mathrm{J_p}} \mathrm{RCRA}_{\mathrm{j,h}}$$

Where:

$TA_{p,h}$	refers to the aggregate *trading amount* of *trading participant p* for *settlement interval h*
$ETA_{j,h}$	refers to the *energy trading amount* of resource *j* at *settlement interval h*
$RTA_{j,r,a,h}$	refers to the *reserve trading amount* of resource *j* for *reserve category r* and *reserve region a* at *settlement interval h*
$TRTA_{j,h}$	refers to the *transmission rights trading amount* of *transmission right t* at *settlement interval h*
$RCRA_{j,h}$	refers to the reserve cost recovery amount of *resource j* for *settlement interval h* computed as the sum of resource $RRCost_{j,REG\text{-}r,a,h}$ and $CRCost_{k,r,a,h}$
J_p	refers to the set of all *resources* associated with *trading participant p*
R_j	refers to the set of all *reserve categories* which *resource j* participate in
T_p	refers to the set of all *transmission rights* associated with *trading participant p*

[41] *WESM Rules* Clause 3.13.13.2

8.5 Additional Compensation

8.5.1 A *Trading Participant* may be entitled to additional compensation when the costs incurred in complying with *dispatch* instructions are not sufficiently covered by the *trading amounts* related to *settlement intervals* with *dispatch intervals*:

a. Under *market suspension* or *market intervention;* or
b. In which the same *Trading Participant* was designated as *must-run unit.*

8.5.2 A *Trading Participant* may also be entitled to additional compensation when the costs incurred in providing *reserves* based on capacity fees are not sufficiently covered by the *trading amounts* related to *settlement intervals* with *dispatch intervals* under *market suspension* or *market intervention*.

8.5.3 *Trading Participants* shall submit sufficient proof regarding the following costs incurred:

a. fuel costs; and
b. variable operating and maintenance costs, which may include start-up cost and shut-down costs.

8.5.4 The additional compensation for *dispatch intervals* under *market suspension* or *market intervention* shall not be more than the difference of the total costs in Section 7.5.3 and the amount of the *energy administered price* or *reserve administered price, as applicable,* already paid or payable, subject to the determination and approval of the *Market Operator*.

8.5.1 Should a *generating unit* be designated as *must-run unit*, the *Market Operator* shall determine the *must-run unit* quantity/volume that shall be considered for additional compensation. This *must-run units* volume is the total *metered quantity* of that *generating unit* minus the *bilateral contract quantity* declared for that unit, as provided in the following formula:

$$\text{MRU Quantity}_{k,\,h} = MQ_{k,\,h} - BCQ_{k,h}$$

Where:

$MQ_{k,\,h}$	refers to the *metered quantity* for *generator* resource *k* at *settlement interval h*
$BCQ_{k,\,h}$	refers to the *bilateral contract quantity* declared for *generator* resource *k* at *settlement interval h*

a. If a *generating unit* was scheduled beyond the minimum limit declared by the *System Operator* in the *security limit*, then the MRU Volume is zero (0).

b. In cases where the calculated *MRU* Volume is less than zero, then the *MRU* Volume is equal to zero.

c. The additional compensation shall be pro-rated to the *customers* in the same region based on *metered quantities*.

8.6 Settlement Amounts

8.6.1 For each *billing period,* the *Market Operator* shall determine the *settlement amount* for each *Trading Participant* as follows:[42]

a. The sum of the aggregate *trading amounts* for the *settlement intervals* in that *billing period*; plus
b. Any amount payable by the *Market Operator* to that *Trading Participant* in respect of that *billing period* and not accounted for in the aggregate *trading amounts;* less
c. The sum of any *market fees* which that *Trading Participant* is required to pay in respect of that *billing period*.

8.6.2 This is provided in the following formula:

$$\mathrm{SA}_{\mathrm{p,m}} = \sum_{\mathrm{h} \in \mathrm{H_m}} \mathrm{TA}_{\mathrm{p,h}} + \mathrm{OTA}_{\mathrm{p,m}} + \mathrm{MF}_{\mathrm{p,m}}$$

Where:

$SA_{p,m}$	refers to the *settlement amount* of *trading participant p* for *billing period m*
$TA_{p,h}$	refers to the aggregate *trading amount* of *trading participant p* for *settlement interval h*
$OTA_{p,m}$	refers to other *trading amounts* of *trading participant p* for *billing period m*
$MF_{p,m}$	refers to the *market fee* payments of *trading participant p* for *billing period m*

SECTION 9 ALLOCATION OF NET SETTLEMENT SURPLUS

9.1 Scope

9.1.1 This section provides the formula used to determine and allocate the *net settlement surplus,* which refers to the difference between the collections from and payments to *Trading Participants.*[43]

9.1.2 This section shall only apply to *energy* transactions since the *reserve* market implements a cost recovery that does not result to any *net settlement surplus.*

[42] *WESM Rules* Clause 3.13.13
[43] *WESM Rules* Clause 3.13.14

9.2 Calculation of Net Settlement Surplus

9.2.1 The *net settlement surplus* amount shall be calculated on an hourly basis as follows:

$$NSS_h = Collectibles_h - Payables_h$$

Where:

NSS_h	refers to the *net settlement surplus* at *settlement interval h*
$Collectibles_h$	refers to the total amount to be collected by the *Market Operator* from the *Trading Participants* for *energy* transactions in the *WESM* at *settlement interval h.*
$Payables_h$	refers to the total amount to be paid by the *Market Operator* to the *Trading Participants* for *energy* transactions in the *WESM* at *settlement interval h*

9.2.2 In case the collectibles are less than the payables resulting to a net settlement deficit, the deficit shall be recovered from the *Trading Participants*. In this case, the *net settlement surplus* referred to would be a negative amount and the rebate referred to shall also be a negative amount.

9.3 Recipient of Net Settlement Surplus

9.3.1 *WESM Trading Participants* that paid for the loss and congestion charge shall receive a share in the *net settlement surplus*.

9.3.2 The allocation mechanism shall only be up to the level of the registered *Trading Participants.*

9.4 Flow Back of Net Settlement Surplus

9.4.1 The *net settlement surplus* shall be allocated to each *WESM Participant* based on each recipient's share in the total amount of loss and congestion charges.

9.4.2 The amount to be returned shall be equal to the ratio of the recipient's loss and congestion charges to the total loss and congestion charges of all recipients multiplied by the total *net settlement surplus* amount, as represented by the following formula:

$$R_{p,h} = NSS_h * \frac{LLCC_{p,h}}{\sum_{p \in P} LLCC_{p,h}}$$

Where:

$R_{p,h}$	refers to the rebate amount or *net settlement surplus* allocation for *Trading Participant p* at *settlement interval h*
NSS_h	refers to the *net settlement surplus* at *settlement interval h*

$LLCC_{p,h}$	refers to the line loss and congestion charges payments of *Trading Participant p* at *settlement interval h*
P	refers to the set of all *Trading Participants*
p	refers to any *Trading Participant* paying line loss congestion charges to which a pro-rated amount of the *net settlement surplus* will be returned

a. The line loss and congestion charge payment is determined as follows:

$$LLCC_{p,h} = \sum_{n \in N_p} \left(LLCP_{n,h} * \sum_{j \in J_{n,p}} GESQ_{j,n,h} \right) - \sum_{c \in C_p} \left(LLCP_{p,c,h} * BCQ_{p,c,h} \right)$$

Where:

$LLCC_{p, h}$	refers to the line loss and congestion charges payments of *Trading Participant p* at *settlement interval h*
$LLCP_{n,h}$	refers to the line loss and congestion price at *market trading node n* at *settlement interval h*
N_p	refers to the set of *market trading nodes* assigned to *WESM Participant p*
$J_{n,p}$	refers to the set of resources of *Trading Participant p* at *market trading node n*
$GESQ_{j,n,h}$	refers to the gross *energy settlement quantity* of *resource j* in *market trading node n* at *settlement interval h*
$LLCP_{p,c,h}$	refers to the line loss and congestion price at the reference bilateral *nodal energy dispatch price* between *Trading Participant p* and counterparty *c* at *settlement interval h*
$BCQ_{p,c,h}$	refers to the declared *bilateral contract quantity* between *WESM Participant p* and counterparty c at *settlement interval h*
C_p	refers to the set of counterparties of *Trading Participant p*

b. In case the line loss and congestion charge payment for a *settlement interval* of a *trading participant* is a positive value, the line loss and congestion charge payment for the *Trading participant* for that *settlement interval* shall be set to zero (0).

c. The line loss and congestion price for a *settlement interval* for each resource is calculated as follows.

$$LLCP_{n,\,h} = \frac{\sum_{i \in I_h} \left\{ \left[\left(MLC_{n,\,h,\,i} + MCC_{n,\,h,\,i} \right) - (\mathrm{MLC} + \mathrm{MCC})_{h,i}^{lowest} \right] * EDS_{j,\,h,\,i} \right\}}{\sum_{i \in I_h} EDS_{j,\,h,\,i}}$$

Where:

$LLCP_{n,h}$	refers to the line loss and congestion price *at market trading node n* at *settlement interval h*

$MLC_{n,h,i}$	refers to the marginal loss cost *at market trading node n* at *dispatch interval i* within *settlement interval h*
$MCC_{n,h,i}$	refers to the marginal congestion cost at *market trading node n* at *dispatch interval i* within *settlement interval h*
$(MCC+MLC)_{h,i}^{lowest}$	refers to the lowest aggregated marginal loss cost and marginal congestion cost for *dispatch interval i* within *settlement interval h*
$EDS_{j,h,i}$	refers to the *energy dispatch schedule* of resource *j* at *dispatch interval i* within *settlement interval h*
I_h	refers to the set of *dispatch intervals* within *settlement interval h*

d. In case the *nodal energy dispatch prices* were not determined using the *market dispatch optimization model* in accordance with *WESM Rules* Clause 3.6, the line loss and congestion cost price of each resource shall be set to zero (0).

9.4.3 In case the *nodal energy dispatch prices* of all resources in all *dispatch intervals* of a *settlement interval* were not determined using the *market dispatch optimization model* in accordance with *WESM Rules* Clause 3.6, the *net settlement surplus* for that *settlement interval* shall be allocated to *customer* resources on a pro-rata basis depending on each *customer* resource's share in the total *metered quantities* of all customer resources. The allocation shall be performed on a per *customer* resource basis associated to the *WESM Participants*. *Generator* resources will not have an allocation of the *net settlement surplus* during this case.

The amount to be returned will be equal to the ratio of the *customer* resource's *metered quantity* to the total *metered quantity* of all customer resources multiplied by the total *net settlement surplus* amount, as represented by the following formula:

$$R_{b,\,h} = NSS_h * \frac{MQ_{b,\,h}}{\sum_{b\in B} MQ_{b,\,h}}$$

Where:

$R_{b,h}$	refers to the rebate amount or *net settlement surplus* allocation for *customer* resource *b* at *settlement interval h*
NSS_h	refers to the *net settlement surplus* at *settlement interval h*
$MQ_{b,h}$	refers to the *metered quantity* of *customer* resource *b* at *settlement interval h*
B	refers to the set of all *customer* resources

SECTION 10 AMENDMENT, PUBLICATION AND EFFECTIVITY

10.1 Review and Update

10.1.1 The *Market Operator* shall review and update this *Market Manual*, as necessary.

10.1.2 Any amendment or revision to this *Market Manual* shall be approved in accordance with Chapter 8 of the *WESM Rules* and corresponding *Market Manual* and by the *ERC.*

10.2 Publication and Effectivity

10.2.1 The publication and effectivity of this *Market Manual* shall be in accordance with the resolution of the *ERC*.

SECTION 11 APPENDICES

Appendix A – Detailed Formulation

Appendix B – Tie Breaking (Illustrative Example)

Generator A and B have a maximum capacity of 70 MW and 90 MW, respectively, and both are located at the same location with the same offer price.

The price curve of Gen A is shown below.

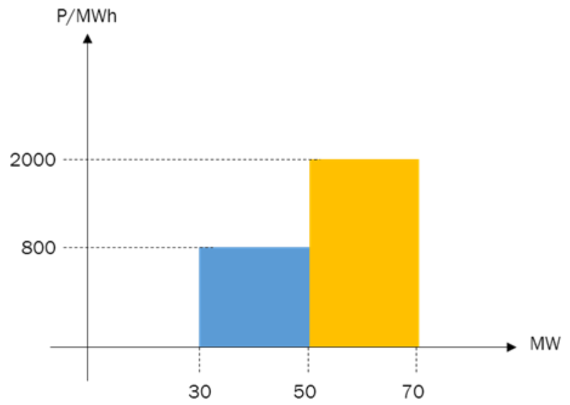

Figure 1. Generator A Price Curve

The price curve of Gen B is shown below.

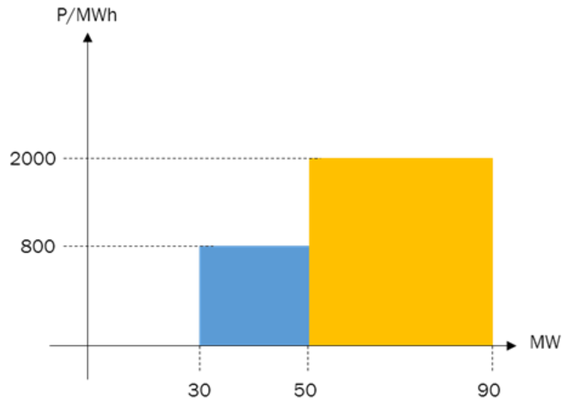

Figure 2. Generator B Price Curve

If the total load is 140 MW, both the first blocks of the price curves of generators A and B shall be scheduled at 50 MW each, hence, fulfilling 100 MW of the 140 MW load requirement.

The remaining 40 MW load requirement shall then be pro-rated as follows.

- Next block in price curve of Gen A is 20 MW at P2,000/MWh
- Next block in price curve of Gen B is 40 MW at P2,000/MWh also

$$\text{Additional Schedule for Gen A} = 40 * \left[\frac{20}{40+20}\right] = 13.33 \text{ MW}$$

$$\text{Additional Schedule for Gen B} = 40 * \left[\frac{40}{40+20}\right] = 26.67 \text{ MW}$$

Provided as such, Generator A shall have a total schedule of 63.33 MW (50+13.33), while Generator B shall have a total schedule of 76.67 MW (50 + 26.67).

Appendix C – Runway Model

As provided in Section 8.3.2, the *reserve* costs for contingency service shall be allocated among *generators* using a “runway model”. Under the runway model, the cost allocated to a *generator* is based on its energy scheduled, representing the amount contributed to the reserve requirement. *Generators* are held responsible for the incremental contribution to the reserve requirement by sharing the costs for the incremental increase with the larger units, and the underlying reserve requirements with the smaller units.

This is illustrated in the following figure:

GEN A SCHED	GEN C SCHED	GEN B SCHED	GEN D SCHED		COUNT OF GENERATORS SHARING IN A BLOCK	GENERATOR ALLOCATION PER BLOCK
250 MW						
GEN A - GEN C	160 MW			COMMON BLOCK 1 = 90 MW	1	1
	GEN C - GEN B	70 MW		COMMON BLOCK 2 = 90 MW	2	0.5
		GEN C - GEN D	40 MW	COMMON BLOCK 3 = 30 MW	3	0.33
			GEN D	COMMON BLOCK 4 = 40 MW	4	0.25

Figure 3. Sample Representation for Run-way Model

In the above figure, the *generators* are ordered by manner of decreasing *energy* schedule. Doing so will show the “common blocks”, which are capacities common to *generators* that necessitate a certain amount of *reserve requirement* and whose cost will be shared equally amongst them.

For instance, Common Block 4 (40 MW) is shared by Gen A, B, C and D, and hence, its cost will be split equally amongst them. In the same manner, Common Block 3 (30 MW) is shared only by Generators A, B and C, in which Gen D has no amount due, as its worst possible *outage* that would utilize *reserve* is limited to 40 MW only.

The Runway Model provides a mean to determine and allocate capacities attributable to generators.

As previously stated, the following formula represents the attributable reserve cost to a certain generator k.

$$CRCost_{k,\,r,\,a,\,h} = RTA_{r,\,a,\,h} * \sum_{p \in P} \left[\frac{GA_{p,\,r,\,a,\,h} * SQTY_{k,\,p,\,r,\,a,\,h}}{\sum_{j \in J} RDS_{j,\,r,\,a,\,h}} \right]$$

Whereas $GA_{p,r,a,h}$ is calculated as follows.

$$GA_{p,\,r,\,a,\,h} = \frac{1}{\text{No. of Generators sharing in block p in reserve area a for } \textit{reserve category} \text{ r at settlement interval h}}$$

Based on Figure *3*, the generator allocation for Common Block 4 is:

$$GA_{4,r,a,h} = \frac{1}{\text{No. of Generators sharing in block 4}} = \frac{1}{4} = 0.25$$

Suppose that the total reserve amount to be paid for certain settlement interval “h” is P30,000, then the reserve cost attributable to GEN D is:

$$CRCost_{D,r,a,\,h} = 30{,}000 * \left[\frac{0.25 * 40}{250} \right] = P1{,}200$$

As for GEN C, it shares in common block 3 and 4. With GA_3 being computed as 0.33 and GA_4 being 0.25 (as shown in Figure *3*), then the reserve cost attributable to GEN C is:

$$CRCost_{C,r,a,\,h} = 30{,}000 * \left[\left(\frac{0.25 * 40}{250} \right) + \left(\frac{0.33 * 30}{250} \right) \right] = P2{,}400$$

Upon completing the example, GEN B will pay P7,800 while GEN A will pay P18,600.