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WESM Manual

Price Determination Methodology Issue No. 2.0

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

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Document Change History

Issue No.	Proponent	Date of Effectivity	Reason for Amendment
	PEMC		The revised Price Determination Methodology, as approved by the ERC on 20 June 2006 under ERC Decision on Case No. 2006-007 RC
1	PEMC		The Price Determination Methodology Market Manual for the 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
2	PEMC		The proposed amendments aim to: (i) revise the proposed calculation of price adjustment for customers in the non-administered region to ensure there is no cross-subsidy when the administered region under market intervention or suspension is exporting power to the non-administered region; (ii) clarify that both Must-Run Units and constrained-on generating units may apply for additional compensation; (iii) specify that Must-Run Units or constrain-on generators are price takers; and (iv) delete the provision stating that administered price will only be

			applied to an isolated portion of the grid under market suspension or intervention since (a) there have been no declaration by the System Operator of local market intervention and suspension that only affects a certain portion of the grid, and (b) the new Market Management System is capable of determining prices for an isolated system in the grid, thereby having no need to declare local market intervention;
			Amendments regarding Pre-Integration of Mindanao in the WESM

Document Approval

Issue No.	RCC Approval	RCC Resolution No.	PEM Board Approval	PEM Board Resolution No.	DOE Approval	DOE Department Circular No.
1	09 November 2016	2016-13	29 November 2016	2016-41	20 March 2017	DC2017-03-0001
2	09 June 2017	2017-07	18 September 2017	2017-17	28 March 2018	DC2018-04-0012
	25 April 2018	2018-01	03 May 2018	2018-19	26 June 2018	2018-06-0017

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* (WESM) is mandated by Republic Act No. 9136, otherwise known as the Electric Power Industry Reform Act of 2001 (EPIRA).

1.1.2 Pursuant to the mandate of the EPIRA, the *Department of Energy* (*DOE*) jointly with the electric power industry participants formulated the *WESM Rules*, which, among others, provide 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. The price determination methodology contained in the WESM Rules is required by the EPIRA to be approved by the *Energy Regulatory Commission* (*ERC*).[1]

1.2 Purpose

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

a. Gross pool, where each *Scheduled Generation Company* offers its *maximum available capacity*, *Non-Scheduled Generation Company* submits a standing nomination of *loading levels*, and *Generation Company,* with *must dispatch generating units* and *priority dispatch generating units,* submits 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* manage 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]
g. Zonal pricing for *reserves*;[8]

[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
[8] *WESM Rules* Clause 3.6.1

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

This *Market Manual* provides the following:

a. Methodology by which *energy* and *reserves* shall be priced and settled in accordance with the market design principles as issued by the *DOE;*[10]
b. Methodology by which *energy* and *reserves* in the *WESM* shall be priced,[11] including the determination of prices when there is extreme price separation due to *network congestion*,[12] and determination of *administered prices* during *market suspension* and *market intervention;*[13]
c. 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;*[14] and
d. 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.

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

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

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 economic 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. **Final Nodal Energy Dispatch Price.** The final nodal price for *energy* after the application of price substitution due to *network congestion* or when conditions for price mitigation exists, or *administered prices*, as applicable.

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

h. **Network Congestion.** The congestion at a line or transformer that is connected in a meshed *network*.

i. **Network Data.** The electrical parameters used to represent the *transmission* and *sub-transmission systems* in the *market network model*.

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

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

l. **Security-constrained economic dispatch.** The process of apportioning the total load on a system between the various generating plants to achieve the greatest economy of operation and taking account of the limitations of the power system.

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

n. **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*.

o. **Snapshot Quantity.** The actual instantaneous injection, withdrawal, or line flow of power, in MW, at the end of a *dispatch interval.*

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

q. **Transmission Loss Factor.** The 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.

r. **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

This *Market Manual* shall be read in association with the *WESM Rules* and other relevant *Market Manuals.*

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

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

3.2 System Operator

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

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

3.4 Network Service Providers

The *Network Service Providers* shall provide the necessary information for the implementation of this *Market Manual.*

SECTION 4 DISPATCH AND PRICING ALGORITHM

4.1 Scope

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* and *Trading Participants*.

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 (3) sources, namely, the *System Operator*, the *Trading Participants*, and the *Market Operator*. The information provided are as required in the *WESM Rules*[15].

4.3.2 *System Operator* and *Network Service Provider* 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*
    - Non-security limits
        - Testing and commissioning

4.3.3 Where applicable, *Trading Participant* Inputs:

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

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[15] *WESM Rules* Clause 3.5

f. *Projected output;* and
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*, less the costs of the following:

a. Dispatched *generation* based on *generation offers*;
b. Dispatched *reserves* based on *reserve offers*;
c. *Load* curtailment; and
d. *Constraint* violation based on *constraint violation coefficients*.[16]

It is represented by the following formulation:

Maximize the *economic gain* from trade, where:

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

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*

[16] *WESM Rules* Clause 3.6.1.3

$PR_{j, r, i}$	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

4.4.2 The objective function can 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 economic 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 economic dispatch* and shall be 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

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 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

[17] *WESM Rules* Clause 3.4.1.2

c. Generic Constraints

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

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 among 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

When restricting *dispatch* targets 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;* and
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* shall always find a solution which satisfies all *constraints*, if such a solution exists. It shall also ensure that, if *constraints* are violated, the violation shall 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*:

[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

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;
f. Base case thermal *constraint*; and
g. Self-scheduled generation *constraint.*

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

a. *Market projections* and *dispatch* scheduling, 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* shall 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

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*
   i. *Energy;* and
   ii. *Reserve;*
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:

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

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:

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

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 as *final nodal energy prices* or *reserve dispatch prices* in the calculation of *settlements* 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

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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

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*[25].

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.

4.13 Final Nodal Energy Dispatch Prices for Customer Zones

4.13.1 If applicable, the *final nodal energy dispatch price* of *customers* that have been approved by the *ERC* to use zonal pricing is further determined as the *customer dispatch schedule*-weighted average of the *final nodal energy dispatch price,* as determined in accordance with Section 4.12, within a *customer pricing zone*, as provided in the following formula:

$$FEDP_{z,b,i} = \frac{\sum_{b \in B_z} \left(FEDP_{b,i} * EDS_{b,i} \right)}{\sum_{b \in B_z} EDS_{b,i}}$$

However, if:

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

Then:

$$FEDP_{z,b,i} = \frac{\sum_{b \in B_z} FEDP_{b,i}}{n_z}$$

Where:

$FEDP_{z,b,i}$	refers to the zonal *final nodal energy price* of *customer* resource *b* at *dispatch interval i* within *customer pricing zone z*
$FEDP_{b,i}$	refers to the *final nodal energy dispatch price* as determined under Section 4.12 for *customer* resource *b* at *dispatch interval i*

[25] ERC Resolution No.20, Series of 2014, dated 15 December 2014, entitled “A Resolution adopting and Establishing a Pre-emptive Mitigation Measure in the Wholesale Electricity Spot Market (WESM)”, which may be amended from time to time.

$EDS_{b,i}$	refers to the *energy dispatch schedule* for *customer* resource *b* at *dispatch interval i*
B_z	set of all *customer resources* within *customer pricing zone z*
n_z	refers to the number of *customer resources* within *customer pricing zone z*

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.[26]

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*.[27]

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 shall have 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.

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

5.2.5 The delta shall be set as small as possible for each *constraint violation coefficient* so that the *automatic pricing re-run* reflects 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[28]
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 market 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 Notwithstanding the application of *automatic pricing re-run*, the *Market Operator* shall issue a *pricing error notice* and perform a market pricing re-run, in the event where the calculated prices are believed to be in error due to erroneous, inconsistent, or inappropriate input data.[29]

5.3.2 The *Market Operator* shall perform the market pricing re-run using appropriately revised inputs for the relevant *dispatch* market run, taking into consideration the applicable solutions for the various causes of erroneous, inconsistent and inappropriate input data.

5.4 Shortage and Excess Prices

[28] EDP refers to *nodal energy dispatch price;* and RP refers to *reserve price*

[29] *WESM Rules* Clause 3.10.5

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

This section provides the price substitution methodology, which shall be implemented by the *Market Operator* in addressing the undesirable market pricing situations that arise from the effects of *network congestion* in the *power system*, particularly during the occurrence of extreme nodal price separation[30].

6.2 Criteria for Determining Extreme Nodal Price Separation 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 load-end transformer, which is the source of the *load* connected to it or of the step-up transformer in a generating plant; and
c. *Constraint* on a radially-connected line.

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:

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

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*
$EDP_{j,i}$	refers to the *nodal energy dispatch price* of resource *j* at *dispatch interval i*

[30] *WESM Rules* Clause 3.12.7

$NWAP_i$ 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, which shall be set at 0.2, subject to annual review. For this purpose, PEMC shall conduct an assessment of the application of the price trigger and the results of the assessment shall be submitted to the WESM Technical Committee for evaluation and for determination as to whether a change in the value of the price trigger is warranted.

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 corresponding to their last MW offer block that was scheduled.

6.3.3 All other generators 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 in the affected pricing region* 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 shall 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*.[31]

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.*

[31] *WESM Rules* Clause 6.2.3

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. 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 using the *snapshot quantity* and either the *nodal energy dispatch prices* or *energy administered prices* of the four (4) most recent similar *trading days* and similar *dispatch intervals* depending on whether or not these have been administered.

7.2.2 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 period within the same *settlement interval*.

7.2.3 In case the *snapshot quantity* for a *generator* resource at a similar *trading day* and similar *dispatch interval* is negative, the *snapshot quantity* 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.

7.2.4 In case one (1) or more of the four (4) most recent similar *trading days* and similar *dispatch intervals* have not been administered, the *energy administered price* for each *generator* resource k shall be computed as follows:

a. *Snapshot quantity*-weighted average of the *nodal energy dispatch prices* of the similar *trading days* and similar *dispatch intervals* that have not been administered as set out in the following formula:

$$EAP_{k,D,i} = \frac{\sum_{d=D-1}^{D-n}\left(FEDP_{k,d,i} * SQ_{k,d,i}\right)}{\sum_{d=D-1}^{D-n} SQ_{k,d,i}}$$

Where:

$EAP_{k,D,i}$	refers to the *energy administered price* for *generator* resource *k* at *dispatch interval i* within *trading day D*
$FEDP_{k,d,i}$	refers to the *final nodal energy dispatch price* for *generator* resource *k* for *dispatch interval i* within *trading day d*
$SQ_{k,d,i}$	refers to the *snapshot quantity* for *generator* resource *k* at *dispatch interval i* within *trading day d*
D	refers to the current *trading day*
D – n	refers to the n^{th} most recent similar *trading day* of *D*
n	refers to the number of similar *trading days* and similar *dispatch intervals* that have not been administered from the four (4) most recent similar *trading days* and similar *dispatch intervals*

b. However, if the *generator* resource had no *snapshot quantity* for the previous similar *trading days* and similar *dispatch intervals*, the *energy administered price* for that *generator* resource shall be determined by obtaining the simple average of the *final nodal energy dispatch prices* of the preceding similar *trading days* and similar *dispatch intervals* that have not been administered as set out in the following formula:

$$EAP_{k,\,D,\,i} = \frac{\sum_{d=D-1}^{D-n} FEDP_{k,\,d,\,i}}{n}$$

Where:

$EAP_{k,\,D,\,i}$	refers to the *energy administered price* for *generator* resource *k* for *dispatch interval i* within *trading day D*
$FEDP_{k,\,d,\,i}$	refers to the *final 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 - n	refers to the n^{th} most recent non-administered similar *trading day* and similar *dispatch interval*
n	refers to the number of similar *trading days* and *dispatch intervals* that have not been administered from the four (4) most recent similar *trading days* and *dispatch intervals*

7.2.5 In case all of the four (4) most recent similar *trading days* and similar *dispatch intervals* have been administered, the *energy administered price* for each *generator* resource k is computed as follows:

a. *Snapshot quantity*-weighted average of the *energy administered prices* of the similar *trading days* and similar *dispatch intervals* as set out in the following formula:

$$EAP_{k,D,i} = \frac{\sum_{d=D-1}^{D-n}\left(EAP_{k,d,i} * SQ_{k,d,i}\right)}{\sum_{d=D-1}^{D-n} SQ_{k,d,i}}$$

Where:

$EAP_{k,D,i}$	refers to the *energy administered price* for *generator* resource *k* at *dispatch interval i* within *trading day D*
$EAP_{k,d,i}$	refers to the *energy administered price* for *generator* resource *k* for *dispatch interval i* within *trading day d*
$SQ_{k,d,i}$	refers to the *snapshot quantity* 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 similar *trading day* of *D*

b. However, if the *generator* resource had no *snapshot quantity* for the previous similar *trading days* and similar *dispatch intervals*, the *energy administered price* for that *generator* resource shall be determined by obtaining the simple average of the *energy administered prices* of the preceding similar *trading days* and similar *dispatch intervals* as set out in the following formula:

$$EAP_{k,\,D,\,i} = \frac{\sum_{d=D-1}^{D-n} EAP_{k,\,d,\,i}}{4}$$

Where:

$EAP_{k,\,D,\,i}$	refers to the *energy administered price* for *generator* resource *k* for *dispatch interval i* within *trading day D*
$EAP_{k,\,d,\,i}$	refers to the *energy administered 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 similar *trading day* and similar *dispatch interval*

7.2.6 In case a *generator* resource does not have *final nodal energy dispatch prices* in the preceding four (4) most recent similar *trading days* and similar *dispatch intervals*, the *energy administered price* for that *generator* resource shall be calculated as follows:

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

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*
$SQ_{k',D,i}$	refers to the *snapshot quantity* 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 *snapshot quantities* at *dispatch interval i*
k'	*refers to a generator resource* with positive *snapshot quantity* at *dispatch interval i* except for *generator resource k*

7.3 Customer Energy Administered Price

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

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

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*
$SQ_{k,i}$	refers to the *snapshot quantity* for *generator* resource *k* at *dispatch interval i*
$SQ_{b,i}$	refers to the *snapshot quantity* for *customer* resource *b* at *dispatch interval i*
K_i	refers to the set of *generator* resources with positive *snapshot quantities* at *dispatch interval i*
B	refers to the set of all *customer* resources at dispatch interval i

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:

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

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*
$SQ_{k,i}$	refers to the *snapshot quantity* for *generator* resource *k* for *dispatch interval i*
$SQ_{ITC,i}$	refers to the *snapshot quantity* of the 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*
$SQ_{b,i}$	refers to the *snapshot quantity* 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:

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

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*
$SQ_{k,i}$	refers to the *snapshot quantity* for *generator* resource *k* at *dispatch interval i*
$SQ_{ITC,i}$	refers to the *snapshot quantity* of the interconnection at *dispatch interval i*
$GWAEAP_i$	refers to the generator weighted average *energy administered price* using *snapshot quantity* for *dispatch interval i*
$SQ_{b,i}$	refers to the *snapshot quantity* (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:

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

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*

$SQ_{ITC,i}$	refers to the *snapshot quantity* of the 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*
$GWAEAP_i$	refers to the generator weighted average *energy administered price* using *snapshot quantity* for *dispatch interval i*
$EDS_{b\text{-}NAR,i}$	refers to the *energy dispatch schedule* of *customer* resource *b* 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 In case one (1) or more of the four (4) most recent similar *trading days* and similar *dispatch intervals* have not been administered, the *reserve administered price* for each *generator* resource k shall be computed as follows:

a. The *reserve dispatch schedule*-weighted average of the *reserve prices* for each *reserve category* of the four (4) most recent similar *trading days* and similar *dispatch intervals* that have not been administered, as set out in the following formula:

$$RAP_{k,r,D,i}=\frac{\sum_{d=D-1}^{D-n}\left(RDP_{k,r,d,i} * RDS_{k,r,d,i}\right)}{\sum_{d=D-1}^{D-n} RDS_{k,r,d,i}}$$

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*
$d = D – n$	refers to the n^{th} most recent non-administered similar *trading day* and similar *dispatch interval*
n	refers to the number of similar *trading days* and *dispatch intervals* that have not been administered from the four (4) most recent similar *trading days* and *dispatch intervals*

b. 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* 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 days* and similar *dispatch intervals* that have not been administered. This is as set out in the following formula:

$$RAP_{k,\ r,\ D,\ i} = \frac{\sum_{d=D-1}^{D-n} RDP_{k,\ r,\ d,\ i}}{n}$$

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 = D-n	refers to the n^{th} most recent non-administered similar *trading day* and similar *dispatch interval*
n	refers to the number of similar *trading days* and *dispatch intervals* that have not been administered from the four (4) most recent similar *trading days* and *dispatch intervals*

7.4.2 In case all of the four (4) most recent similar *trading days* and similar *dispatch intervals* have been administered, the *reserve administered price* for each *generator* resource k shall be computed as follows:

a. *Reserve dispatch schedule*-weighted average of the *reserve administered prices* of the similar *trading days* and similar *dispatch intervals* as set out in the following formula:

$$RAP_{k,D,i} = \frac{\sum_{d=D-1}^{D-n}\left(RAP_{k,d,i} * RDS_{k,d,i}\right)}{\sum_{d=D-1}^{D-n} RDS_{k,d,i}}$$

Where:

$RAP_{k,D,i}$	refers to the *reserve administered price* for *generator* resource *k* at *dispatch interval i* within *trading day D*
$RAP_{k,d,i}$	refers to the *reserve administered price* for *generator* resource *k* for *dispatch interval i* within *trading day d*
$RDS_{k,d,i}$	refers to the *reserve 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 similar *trading day* of *D*

b. However, if the *generator* resource had no *reserve dispatch schedules* for the previous similar *trading days* and similar *dispatch intervals*, the *reserve administered price* for that *generator* resource shall be determined by obtaining the simple average of the *reserve administered prices* of the preceding similar *trading days* and similar *dispatch intervals* as set out in the following formula:

$$RAP_{k,\,D,\,i} = \frac{\sum_{d=D-1}^{D-n} RAP_{k,\,d,\,i}}{4}$$

Where:

$RAP_{k,\,D,\,i}$	refers to the *reserve administered price* for *generator* resource *k* for *dispatch interval i* within *trading day D*
$RAP_{k,\,d,\,i}$	refers to the *reserve administered 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 similar *trading day* and similar *dispatch interval*

7.4.3 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*.

7.4.4 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 period within the same *settlement 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

This section provides the following:

a. Formula used to determine the *trading* and *settlement amounts* for *energy* and *reserves* for each *Trading Participant*;[32]
b. Formula to determine the costs of *reserves* to be recovered through the settlement amounts calculated;[33] and
c. Provision of additional compensation for *Trading Participants* affected by *market suspension or market intervention* or are designated as *must-run units.*

8.2 Trading Amounts

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

8.2.1 Energy Trading Amount[34]

The *energy trading amount* for a *market trading node* and *settlement interval* shall be determined using the *final energy dispatch prices* for that *node,* the *gross energy settlement quantities,* as determined under *WESM Rules* Clause 3.13.6, and *bilateral contract quantities* for that *node* in the *dispatch intervals* within the same *settlement interval.* It shall be calculated for generators and customers as follows:

i. Generators

$$ETA_{k,h} = \sum_{i \in h} \left[\left(FEDP_{k,i} * GESQ_{k,i} \right) - \sum_{b \in B_i} \left(FEDP_{k,b,i} * BCQ_{k,b,i} \right) \right]$$

Where:

$ETA_{k,h}$	refers to the *energy trading amount* of resource *k* at *settlement interval h*
$FEDP_{k,i}$	refers to the *final energy dispatch price* of *generator* resource *k* at *dispatch interval i* in *settlement interval h*
$GESQ_{k,i}$	refers to the *gross energy settlement quantity* for *generator* resource *k* at *dispatch interval i* in *settlement interval h*
$FEDP_{k,b,i}$	refers to the reference *final nodal energy dispatch price* for the *bilateral contract quantity* between *generator* resource *k* and *load* resource *b* at *dispatch interval i* in *settlement interval h* (default is *generator* FEDP)
$BCQ_{k,b,i}$	refers to the *bilateral contract quantity* for *generator* resource k to counterparty *load* resource *b* at *dispatch interval i* in *settlement interval h*
B_i	refers to the total number of resources that generator resource *k* has a contract with at *dispatch interval i*

ii. Customers/Buyers

$$ETA_{b,h} = \sum_{i \in h} \left[\left(FEDP_{b,i} * GESQ_{b,i} \right) - \sum_{k \in K_i} \left(FEDP_{b,k,i} * BCQ_{b,k,i} \right) \right]$$

Where:

$ETA_{b,h}$	refers to the *energy trading amount* of *load* resource b at *settlement interval h*

[34] *WESM Rules* Clause 3.13

$FEDP_{b,i}$	refers to the *final energy dispatch price* of *load* resource *b* at *dispatch interval i* in *settlement interval h*
$GESQ_{b,i}$	refers to the *gross energy settlement quantity* for *load* resource *b* at *dispatch interval i* in *settlement interval h*
$FEDP_{b,k,i}$	refers to the reference *final energy dispatch price* for the *bilateral contract quantity* between *generator* resource k and *load* resource *b* at *dispatch interval i* in *settlement interval h* (default is *generator* FEDP)
$BCQ_{b,k,i}$	refers to the *bilateral contract quantity* for *load* resource b to counter-party *generator* resource *k* at *dispatch interval i* in *settlement interval h*
K_i	refers to the total number of resources that customer resource *b* has a contract with at *dispatch interval i* in *settlement interval h*

8.2.2 Reserve Trading Amount[35]

a. The *reserve quantity* for any *market trading node* in any *dispatch interval* shall be determined by the *Market Operator* as the *reserve dispatch schedule* less *reserve* contracted quantities.

$$RQ_{j,\, r,\, a,\, i} = \left(RDS_{j,\, r,\, a,\, i} - RBCQ_{j,\, r,\, a,\, i}\right)$$

Where:

$RQ_{j, r, a, i}$	refers to the *reserve quantity* of 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* of resource *j* for *reserve category r* and *reserve region a* at *dispatch interval i*
$RBCQ_{j, r, a, i}$	refers to the *bilateral contract quantity* for resource *j* for *reserve category r* and *reserve region a* at *dispatch interval i*

b. The *reserve trading amount* for each *Trading Participant* who supplies reserve to a particular *reserve region* in a *settlement interval* shall be determined from the *reserve dispatch prices* for that *reserve region* multiplied by the *reserve quantities* for that *Trading Participant* in that *reserve region* for the respective *dispatch intervals* in that *settlement interval.*

$$RTA_{j,\, r,\, a,\, h} = \frac{1}{n}\sum_{i \in h}\left(RDP_{j,\, r,\, a,\, i} * RQ_{j,\, r,\, a,\, i}\right)$$

Where:

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

[35] *WESM Rules Clause* 3.13

$RDP_{j, r, a, i}$	refers to the reserve dispatch price of resource j for reserve category r and reserve region a at dispatch interval i in settlement interval h
$RQ_{j, r, a, i}$	refers to the reserve quantity of resource j for reserve category r and reserve region a at dispatch interval i in settlement interval h
n	refers to the number of dispatch intervals within a settlement interval

8.2.3 Reserve Cost Recovery

a. Cost Recovery for Regulation Service

The 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 *gross energy settlement quantities*, as determined under *WESM Rules* Clause 3.13.6, using the formula represented as:

$$RRCost_{j,\ REG\text{-}r,\ a,\ h} = \sum_{i \in h} \left(\frac{RTA_{REG\text{-}r,\ a,\ i}}{\sum_{j \in J} GESQ_{j,\ a,\ i}} * GESQ_{j,\ a,\ i} \right)$$

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*
$RTA_{REG\text{-}r, a, i}$	refers to the *reserve trading amount* for the regulation service in *reserve region a* for regulation reserve category REG-r at *dispatch interval i* within *settlement interval h*
$GESQ_{j, a, i}$	refers to the *gross energy settlement quantity* of resource *j* in *reserve region a* at *dispatch interval i* within *settlement interval h*

b. Cost Recovery for Contingency Service

i. The *reserve* costs for raise contingency service shall be allocated among *generators* using the following formula:[36]

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

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*

[36] See Appendix C for explanatory example

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

$$GA_{p,\,r,\,a,\,i} = \frac{1}{\text{No. of Generators sharing in block p in reserve area a for } \textit{reserve category} \text{ r at dispatch interval i}} \; x \left(\frac{\sum_{j \in J} RDS_{j,\,r,\,a,\,i}}{\text{Highest Unit Online}} \right)$$

ii. The *reserve* costs for lower contingency service shall be allocated among *loads* using *gross energy settlement quantities*, as determined under *WESM Rules* Clause 3.13.6, as provided in the following formula:

$$CRCost_{b,\,r,\,a,\,h} = \sum_{i \in h} \left(RTA_{r,a,i} * \frac{GESQ_{b,\,a,\,i}}{\sum_{b \in B} GESQ_{b,\,a,\,i}} \right)$$

Where:

$CRCost_{b, r, a, h}$	refers to the *reserve* cost to be paid by *load b* in *reserve region a* for reserve category r at *settlement interval h*
$RTA_{r, a, i}$	refers to contingency *reserve trading amount* in *reserve region a* for reserve category r at *dispatch interval i* within *settlement interval h*
$GESQ_{b, a, i}$	refers to the *gross energy settlement quantity* of *load b* in *reserve region a* at *dispatch interval i*

8.2.4 Aggregate Trading Amount

a. The aggregate *trading amount* for a *Trading Participant* for a *settlement interval* is determined shall be determined as follows:[37]

i. *Energy trading amounts,* which may be positive or negative for any *Trading Participant;* plus
ii. *Reserve trading amounts* for each *reserve region,* which shall 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

[37] *WESM Rules* Clause 3.13

iv. The *reserve cost recovery charges* 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:

$$TA_{p,h} = \sum_{j \in J_p} ETA_{j,h} + \sum_{j \in J_p} \sum_{r \in R_j} RTA_{j,r,a,h} + \sum_{t \in T_p} TRTA_{t,h} - \sum_{j \in J_p} RCRA_{j,h}$$

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 $RRCost_{j, REG-r, a, h}$, $CRCost_{k, r, a, h}$, and $CRCost_{b, r, a, h}$, as applicable
J_p	refers to the set of all *resources* associated with *trading participant p*
R_j	refers to the set of all *reserve categories* participated in by *resource j*
T_p	refers to the set of all *transmission rights* associated with *trading participant p*

8.3 Additional Compensation

8.3.1 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* under any of the following conditions:

a. *Market suspension* or *market intervention* and was paid at the administered price in accordance with Section 7*;* or

b. When the same *Trading Participant* was designated as *must-run unit* or *constrain-on generating unit* and was paid at the WESM price in accordance with Section 4.12*.*

8.3.2 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 *dispatch intervals* under *market suspension* or *market intervention*.

8.3.3 *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.

8.3.4 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 8.3.3 and the amount of the *energy administered price* or *reserve administered price, as applicable,* either paid or payable, subject to the determination and approval of the *Market Operator*.

8.3.5 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 *gross energy settlement quantity*, as determined under WESM Rules Clause 3.13.6, of that *generating unit* minus the *bilateral contract quantity* declared for that unit, as provided in the following formula:

$$\text{MRU Quantity}_{k,\,i} = \text{GESQ}_{k,i} - \text{BCQ}_{k,i}$$

Where:

$GESQ_{k,\,i}$	refers to the *gross energy settlement quantity* for *generator* resource *k* at *dispatch interval i*
$BCQ_{k,\,i}$	refers to the *bilateral contract quantity* declared for *generator* resource *k* at *dispatch interval i*

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

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

c. The additional compensation shall be pro-rated among the *customers* in the same region based on *gross energy settlement quantities*.

8.4 Settlement Amounts

8.4.1 For each *billing period,* the *Market Operator* shall determine the *settlement amount* for each *Trading Participant* as follows: [38]

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

[38] *WESM Rules* Clause 3.13

c. The sum of any *market fees* which that *Trading Participant* is required to pay in respect of that *billing period*.

8.4.2 This is provided in the following formula:

$$\mathrm{SA_{p,m}} = \sum_{\mathrm{h \in H_m}} (\mathrm{TA_{p,h}} + \mathrm{OTA_{p,h}}) - \mathrm{MF_{p,m}}$$

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*
$OTA_{p,h}$	refers to other *trading amounts* of *trading participant p* for *settlement interval h*
$MF_{p,m}$	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.*[39]

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.*

9.2 Calculation of Net Settlement Surplus

9.2.1 The *net settlement surplus* amount shall be calculated per *dispatch interval* as follows:

$$\mathrm{NSS_i} = \mathrm{Collectibles_i} - \mathrm{Payables_i}$$

Where:

NSS_i	refers to the *net settlement surplus* at *dispatch interval i*
$Collectibles_i$	refers to the total amount to be collected by the *Market Operator* from the *Trading Participants* for *energy* transactions in the *WESM* at *dispatch interval i*
$Payables_i$	refers to the total amount to be paid by the *Market Operator* to the *Trading Participants* for *energy* transactions in the *WESM* at *dispatch interval i*

[39] *WESM Rules* Clause 3.13

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:

$$R_{p,h} = \sum_{i \in h}\left(NSS_i * \frac{LLCC_{p,i}}{\sum_{p \in P} LLCC_{p,i}}\right)$$

Where:

$R_{p,h}$	refers to the rebate amount or *net settlement surplus* allocation for *Trading Participant p* at *settlement interval h*
NSS_i	refers to the *net settlement surplus* at *dispatch interval i*
$LLCC_{p,i}$	refers to the line loss and congestion charges payments of *Trading Participant p* at *dispatch interval i*
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 shall be determined as follows:

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

Where:

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

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

c. The line loss and congestion price for a *dispatch interval* for each resource shall be calculated as follows:

$$\mathrm{LLCP}_{n,\,i}=\left(\mathrm{MLC}_{n,\,i}+\mathrm{MCC}_{n,\,i}\right)-(\mathrm{MLC}+\mathrm{MCC})_{\mathrm{i}}^{\mathrm{lowest}}$$

Where:

$LLCP_{n,i}$	refers to the line loss and congestion price *at market trading node n* at *dispatch interval i*
$MLC_{n,i}$	refers to the marginal loss cost *at market trading node n* at *dispatch interval i*
$MCC_{n,i}$	refers to the marginal congestion cost at *market trading node n* at *dispatch interval i*
$(MCC+MLC)_i^{lowest}$	refers to the lowest aggregated marginal loss cost and marginal congestion cost for *dispatch interval i*

d. In case the *nodal energy dispatch price* of a resource was not determined using the *market dispatch optimization model* in accordance with *WESM Rules* Clause 3.6, the line loss and congestion cost price of that resource shall be set to zero (0). Consequently, that resource shall have zero (0) *net settlement surplus allocation* for that *dispatch interval*.

9.4.3 In case the *nodal energy dispatch prices* of all resources in a *dispatch interval* were not determined using the *market dispatch optimization model* in accordance with *WESM Rules* Clause 3.6, the *net settlement surplus* for that *dispatch interval* shall be allocated to *customer* resources on a pro-rata basis depending on each *customer* resource's share in the total *gross energy settlement quantity, as determined under WESM Rules Clause 3.13.6,* of all customer resources. The allocation shall be performed on a per *customer* resource basis associated to the *WESM Participants*. *Generator* resources shall not have an allocation of the *net settlement surplus* during this case.

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

$$R_{b,\,i} = NSS_i * \frac{GESQ_{b,\,i}}{\sum_{b \in B} GESQ_{b,\,i}}$$

Where:

$R_{b,i}$	refers to the rebate amount or *net settlement surplus* allocation for *customer* resource *b* at *dispatch interval i*
NSS_i	refers to the *net settlement surplus* at *dispatch interval i*
$GESQ_{b,i}$	refers to the *gross energy settlement quantity* of *customer* resource *b* at *dispatch interval i*
B	refers to the set of all *customer* resources

9.5 Submission of Report to the ERC

The *Market Operator* shall submit an annual report on monthly levels of *net settlement surplus* and review of underlying factors giving rise to *net settlement surplus* every June 25 of the following year**.**

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* on rules change process***.***

10.1.3 After the *DOE's* promulgation, the *Market Operator* shall file with the *ERC* for the final approval of the pricing and settlement provisions of this *Market Manual*.

10.2 Publication and Effectivity

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

10.3 Provisions Prior to Interconnections of Mindanao

For *WESM settlements* to reflect the actual physical transactions in Luzon, Visayas, and Mindanao, calculations and procedures on administered price determination methodology and *net settlement surplus* as identified in Appendix D shall be performed per settlement region until the interconnection of Luzon/Visayas and Mindanao.

SECTION 11 APPENDICES

APPENDIX A – DETAILED MATHEMATICAL FORMULATION

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SECTION 1 OPTIMIZATION OBJECTIVE

The optimization objective fits the least-cost multi-product co-optimization methodology that maximizes economic efficiency and relieves *network congestion* while respecting physical constraints. The mathematical formulation is minimization of market payments which in equivalent form can be expressed as maximization of the economic value of dispatched load.

1.1. Maximization of *Economic Gain*

1.1.1. Maximum economic efficiency of the system operation can be achieved through the least-cost *security constrained dynamic dispatch* (SCDD) with co-optimization of multiple electricity commodities.

1.1.2. *Energy* and *reserve* costs present integrated *bid* and *offer* price curves. The price curves are stepwise functions of procured services, therefore costs are piecewise linear functions of service quantities. With price curves being stepwise, the objective function of *Economic Gain* can be expressed as the objective function in Section 4.4 of the Price Determination Methodology *Market Manual*.

1.1.3. The maximization of the overall system costs can be expressed as an SCDD problem with the following optimization objective function in generalized form:

$\max_{En,AS}\{$ Co-optimization objective as maximization of the *Economic Gain*:

$-\sum_{t\in T}(\rho^t \cdot \sum_{unit\in G} C_{unit}^{En;t}(En_{unit}^t))$	- *Energy offer* costs
$-\sum_{t\in T}(\rho^t \cdot \sum_{unit\in G}\left(C_{unit}^{RegRaise;t}(Reg_{unit}^{Raise;t}) + C_{unit}^{RegLower;t}(Reg_{unit}^{Lower;t})\right))$	- Regulation Raise and Regulation Lower *offer* costs
$-\sum_{t\in T}(\rho^t \cdot \sum_{unit\in G} C_{unit}^{FFCS;t}(FFCS_{unit}^t))$	- Contingency *offer* costs
$+\sum_{t\in T}(\rho^t \cdot \sum_{unit\in L} C_{load}^{En;t}(En_{load}^t))$	- *Load bid* income
$-\sum_{t\in T}(\rho^t \cdot \sum_{load\in L} C_{load}^{curt})$	- *Load* curtailment costs
$-\sum_{t\in T}(\rho^t \cdot \sum_{constr\in Constraint\ Set} C_{constr}^{vio}\left(CV_{constr}^t\right)) \quad \}$	- Constraint violation costs

In this formulation, cost terms are related with *Offers* while *Bids* are treated as income – i.e. *Offer* price terms have negative sign in objective.

1.1.4. *Self-scheduled energy* is incorporated into *bid* and *offer* limits during optimization by respective price/quantity pairs (PQ segments), where the quantity is the self-scheduled value, while the price is reflective of the prioritization price for the particular self-schedule type (i.e. schedule priority). Prices are negative for *offer* self-schedules (i.e. projected *generation*) and positive for *bid* self-schedules (i.e. forecasted *load* quantities).

1.2. Minimization of Market Payments

1.2.1. The formulation in Section 1.1 is equivalent to the Objective Function defined as minimization of Market Payments, where the same terms are used but with opposite signs. Equivalent minimization form can be expressed as:

$\min_{En,AS}\{$ Least-cost co-optimization objective as minimization of market payments:

$+\sum_{t\in T}(\rho^t \cdot \sum_{unit\in G} C_{unit}^{En;t}(En_{unit}^t))$	- *Energy offer* costs
$+\sum_{t\in T}(\rho^t \cdot \sum_{unit\in G}\left(C_{unit}^{RegRaise;t}(Reg_{unit}^{Raise;t}) + C_{unit}^{RegLower;t}(Reg_{unit}^{Lower;t})\right))$	- Regulation Raise and Regulation Lower *offer* costs
$+\sum_{t\in T}(\rho^t \cdot \sum_{unit\in G} C_{unit}^{FFCS;t}(FFCS_{unit}^t))$	- Contingency *offer* costs
$-\sum_{t\in T}(\rho^t \cdot \sum_{unit\in L} C_{load}^{En;t}(En_{load}^t))$	- *Load bid* income
$+\sum_{t\in T}(\rho^t \cdot \sum_{load\in L} C_{load}^{curt})$	- *Load* curtailment costs
$+\sum_{t\in T}(\rho^t \cdot \sum_{constr\in Constraint\ Set} C_{constr}^{vio}\left(CV_{constr}^t\right))\quad\}$	- Constraint violation costs

Where:

$\rho^t = \frac{\Delta_t}{60}$ is market time interval length (Δ_t) expressed as fraction of one hour (60 minutes)

SECTION 2 SYSTEM CONSTRAINTS

The main operational system requirements consist of power balance, contingency reserves requirements and regulation capability requirements. In addition, *transmission network* power flow *constraints* (base case and *contingency* cases) are also considered System *Constraints*.

2.1. System Power Balance

2.1.1. The system power balance is a common requirement for all short-term forward markets forcing the system power balance at each trading time interval. The shadow cost of *load* balance presents *system marginal price* for *energy* and also detects unit that is system marginal.

2.1.2. System power balance can be expressed as an equality equation with difference between variable *supply* and variable *demand* (price sensitive or curtailable) on one side and firm (forecasted) *demand* and losses on the other side.

$$\sum_{unit\in G} En_{unit}^t - \sum_{load\in L} En_{load}^t = En_{req}^t + En_{loss}^t \;;\; t\in T$$

2.1.3. In its formulation, the power balance is extended for slack variables for under-generation and over-generation condition as:

$$\sum_{unit \in G} En^t_{unit} - \sum_{load \in L} En^t_{load} + Q_{UG} = En^t_{req} + En^t_{loss} + Q_{OG} \; ; t \in T$$

Where:

Q_{UG} and Q_{OG} are slack variables for under and over *generation*.

2.1.4. As the *generation* and *load* terms are function of *bid*/*offer* quantities, the power balance equation can be written as:

$$\sum_i \sum_j G_{i,j} + Q_{UG} = \sum_i DB_i + \sum_a P_{Loss,a} + Q_{OG}$$

Where:

$\sum_a P_{Loss,a}$ is the sum of all transmission losses in the system and the *generation offer* quantities and *load bid* quantities (G and DB variables) include projected *generation* and forecasted *load* terms, respectively.

This is somewhat a simplified formulation, where the whole system is connected by electrically contiguous AC *network* and there are no export/imports to the system.

2.1.5. The *network energy* losses are linearized using incremental loss factors around the base operating point in respect to *generators* and *loads*:

$$En^t_{loss} = En^{base;t}_{loss} + \Delta En^t_{loss} ; t \in T$$

Where:

$$\Delta En^t_{loss} = \sum_{unit \in G} \alpha^t_{node} \cdot (En^t_{unit} - En^{base;t}_{unit}) - \sum_{load \in L} \alpha^t_{node} \cdot (En^t_{load} - En^{base;t}_{load}) \; ; t \in T \, .$$

2.1.6. The *energy* requirement can present the sum of fixed *loads* and *generations*, system *load forecast* or actual *energy* imbalance. The *market network model* provides for a mix of self-scheduled and offered *generation* on *supply* side and a mix of forecasted nodal *load* and *load bids* on *demand* side.

2.1.7. *Load offers* are considered to represent delivered *load*. The market *energy* balance can be expressed in terms of loss penalty factors and uninterruptible market *energy* requirement as:

$$\sum_{unit \in G} En^t_{unit} / pf^t_{unit} - \sum_{load \in L} En^t_{load} / pf^t_{load} = En^t_{req} + \Delta En^t_{req} ; t \in T$$

Where:

$$\Delta En_{req}^{t} = En_{loss}^{base;t} - \sum_{unit \in G} \alpha_{node}^{t} \cdot En_{unit}^{base;t} + \sum_{load \in L} \alpha_{node}^{t} \cdot En_{load}^{base;t} \; ; t \in T$$

and loss penalty factors are calculated as follows:
$pf_{unit}^{t} = 1/(1-\alpha_{node}^{t})$ and $pf_{load}^{t} = 1/(1+\alpha_{node}^{t})$

Utilizing the notation given in Appendix A.1, namely, $\alpha_{node}^{t} = \frac{\partial P_{loss}^{t}}{\partial P_{node}}$ the loss penalty factor term can be written in the form: $pf_{unit}^{t} = \frac{1}{(1-\frac{\partial P_{loss}^{t}}{\partial P_{node}})}$

pf_{unit}^{t} is also referred to as the *transmission loss factor* (TLF).

Islanded Operation

2.1.8. In accordance to the centralized concept of the system operation, only a single system wide power balance is considered. However, in case of electric islanding condition, or when parts of electric grid are connected only by *HVDC* links, a separate *load* balance equation will be applied for each energized electrical island.

2.1.9. There will be mapping of *nodes* (*loads* and *generators*) to islands. Based on that mapping, SCDD will formulate *load* balance equation for each island. Accordingly, *shadow price* on the relevant *energy* balance constraint will be calculated for each electrical island. In case of islanding, there is no system level power balance but each region has its own power balance equation.

2.1.10. For each electrical island *i* the following equation will be written for a given time interval *t:*

$$\sum_{unit \in Gi} En_{unit}^{t} - \sum_{load \in Li} En_{load}^{t} + Q^{i}{}_{UG} = En_{req}^{i,t} + En_{loss}^{i,t} + Q^{i}{}_{OG} \; ; t \in T$$

2.1.11. During the islanding condition, congestion in one island does not affect the congestion of other islands. Losses are also calculated per island.

2.1.12. In scenario where *grids* are connected only by *HVDC* link, additional terms presenting DC pole injections for each *HVDC* link *dc* connected to particular grid *i* will show in each grid *i load* balance.

$$\sum_{unit \in Gi} En_{unit}^{t} - \sum_{load \in Li} En_{load}^{t} + \sum_{dc \in HVDCi} En_{dc}^{t} + Q^{i}{}_{UG} = En_{req}^{i,t} + En_{loss}^{i,t} + Q^{i}{}_{OG} \; ; t \in T$$

Term En_{dc}^{t} is positive for *HVDC* imports and negative for *HVDC* exports.

2.2. Regional Reserve Requirements

2.2.1. The *reserve requirements* can be specified for each *reserve region*. *Reserve regions* are the same for all *reserves* and for all time intervals. Nevertheless, separate requirements can be specified for each *reserve region*, each *reserve category* and each scheduling time interval. The overall system is treated as a *reserve region.*

Regulation Raise and Regulation Lower Reserve Requirements

2.2.2. The regulation capability is provided through the regulation capacity market segment. Separate minimal requirements for Regulation Raise capacities:

$$\underline{Reg}_{ASreq}^{Raise;t} \leq \sum_{unit \in AS} Reg_{unit}^{Raise;t} \; ; t \in T$$

and maximal and minimal requirements for Regulation Lower capacities:

$$\underline{Reg}_{ASreq}^{Lower;t} \leq \sum_{unit \in AS} Reg_{unit}^{Lower;t} \leq \overline{Reg}_{ASreq}^{Lower;t} \; ; t \in T$$

2.2.3. Only online generating units can be awarded regulation service to contribute to the regional regulation requirements.

2.2.4. The Regulating reserve requirements equations also include slack variables for insufficient regulating reserve.

Contingency Reserve Requirements

2.2.5. Analogously to Regulating Reserve Raise and Regulating Reserve Lower minimal requirements, regional minimum requirements can be specified for other ancillary services (AS) and for each time interval:

$$\underline{Res}_{ASreq}^{t} \leq \sum_{unit \in AS} Res_{unit}^{t} \; ; t \in T$$

2.2.6. The Contingency Reserve requirements equations also include slack variables for insufficient contingency reserve.

2.3. Reserve provider capacity caps

2.3.1. Reserve Provider capacity caps are group *constraints*, where an aggregated award may be less than or equal to a specified value. Capacity caps are defined per:

a. Ancillary Service provider (Market Participant)
b. Class of Ancillary Service providers

2.3.2. In both cases the equation can be written as:

$$\sum_{unit \in AS\ Group} Res_{unit}^{t} \leq \overline{Res}_{AS;\ AS\ Group}^{t}\ ;t \in T\ ,$$

Where AS Group can be each affected AS provider or AS provider class.

2.4. AC Power Flow Model

2.4.1. Accurate power flow results presenting physical system operation are essential for market operation. The power balance equations for some *network node k* having incident *nodes* m can be specified in the following form:

$$P_{node}^{k} = V_{node}^{k} \sum_{m \in I_k} V_{node}^{m} [G_{line}^{km} \cos(\theta_{node}^{k} - \theta_{node}^{m}) + B_{line}^{km} \sin(\theta_{node}^{k} - \theta_{node}^{m})]$$

$$Q_{node}^{k} = V_{node}^{k} \sum_{m \in I_k} V_{node}^{m} [G_{line}^{km} \sin(\theta_{node}^{k} - \theta_{node}^{m}) - B_{line}^{km} \cos(\theta_{node}^{k} - \theta_{node}^{m})]$$

2.4.2. The AC power flow equations completely determine the *network* operating state and their solution $[V_{node}^{k;base};\theta_{node}^{k;base}]$ is calculated for all *network nodes*.

2.4.3. This solution is considered as the base *network* state. All nodal power flow injections, line power flows and *network* losses are calculated for the base *network* state. Additionally *network energy* loss sensitivities and *transmission line* shift factors are calculated to provide a linearized AC model for the *network* base state.

2.4.4. The AC power flow respects unit MW limits, MVAR limits, scheduled voltages for local voltage controlled buses and limits on shunt capacitor banks, load tap changer (LTC) taps and phase-shifter taps.

2.4.5. In cases when nodal *loads* include losses the AC power flow uses *load* distribution slack to allocate *network energy* losses. The adjusted *load* schedules present the delivered nodal *loads* corresponding to the *generation* schedules. If *load* schedules present delivered *load* themselves then *network energy* losses are distributed to the *generation* schedules.

Network Loss Model

2.4.6. Summing up all AC power flow nodal balance equations, including *network energy* losses, the system power balance equation in terms of nodal *generation* and *load* schedules is obtained:

$$\sum_{node \in G} P_{node}^{base;t} - \sum_{node \in L} P_{node}^{base;t} = \sum_{node \in G \cup L} P_{node}^{fix;t} + P_{loss}^{base;t}(P_{G}^{base;t}, P_{L}^{base;t})\ ;\ t\ \in T$$

2.4.7. Both *generation* and *load* nodal power injections are expressed as positive values. At the same time, the nodal loss sensitivity factors are calculated as derivatives of *network energy* losses in respect to *generation* nodal power injections. Therefore, the *load* sensitivity loss factors are equal to the negative *generation* nodal loss factors.

2.4.8. The loss sensitivity factors are calculated using a reference bus approach. The resulting linearized model for *network* losses can be specified as follows:

$$P_{loss}^{t}(P_G^t, P_L^t) = P_{loss}^{t}\left(P_G^{base;t}, P_L^{base;t}\right) + \sum_{node \in G} \alpha_{node}^{t} \cdot \left(P_{node}^{t} - P_{node}^{base;t}\right) - \sum_{node \in L} \alpha_{node}^{t} \cdot \left(P_{node}^{t} - P_{node}^{base;t}\right);\ t \in T$$

Line Power Flow Limits

2.4.9. Transmission branches/paths congested due to *energy* schedules are considered for both the base case and *contingency* cases. The branch flow MVA limits are translated into MW limits, making the assumption that MVAR branch flows and voltage magnitudes do not change significantly due to active power rescheduling. The MW line flow limits are calculated as:

$$\overline{P}_{line}^{t} = SQRT(\overline{MVA}_{line}^{t} **2 - Q_{line}^{b;t} **2); \quad t \in T .$$

2.4.10. The *transmission line* flows are expressed as linearized functions of the nodal power injections around the base operating state using calculated Shift Factors:

$$P_{line}^{t} = P_{line}^{base;t} + \sum_{node \in N} SF_{line}^{node} \cdot \left(P_{node}^{t} - P_{node}^{base;t}\right);\ line \in N;\ t \in T$$

2.4.11. The branch power flows of critical *transmission lines* are limited in both directions:

$$\underline{P}_{line}^{t} \le P_{line}^{t} \le \overline{P}_{line}^{t}; \quad line \in N; \quad t \in T$$

2.4.12. When solving the base case the limit used is the Normal limit. When a *contingency* case is being solved, the flows are checked against the *Contingency* limit. It is required that the *Contingency* limit be the same or greater than the Normal limit.

2.4.13. The set of critical transmission lines is selected according to the percentage of line MW loading. The lines loaded above the specified threshold are included.

2.4.14. The branch power flows equations also include segmented slack variables for limit violation.

2.5. Constraints on HVDC operation

2.5.1. The *HVDC* operation in the optimization problem is modeled by introduction of the concept of *HVDC* Resource. *HVDC* Resource is a modeling vehicle to represent the flow MW and flow direction on the *HVDC* line, as well as other *HVDC* operational *constraints*, like the minimum time required to change the flow direction. The *HVDC* Resource MW schedule (injection) is also representing *network* injection or withdrawal for AC *network* at the DC terminal. The model is illustrated below.

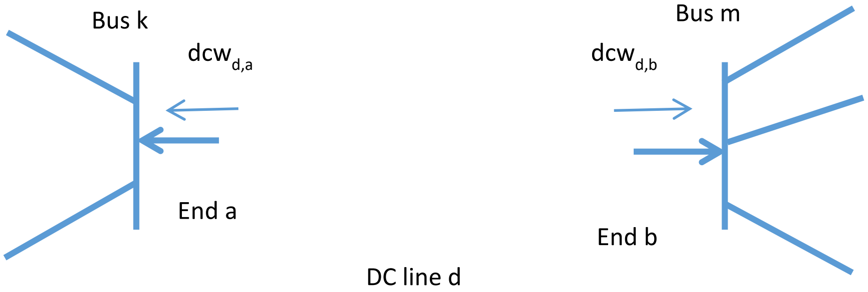

Figure 1: HVDC model

In Figure 1, the DC line *d* goes between the AC buses *k* and *m*. An assignment of ends has been done as End *a* and End *b*. Assume that End *a* is the end where interchange schedules are assumed to flow. This figure shows the model that is implemented in the optimization problem formulation, where the DC line itself has been replaced by a coordinated pair of DC injections.

$dcw_{d,a}^{t}$ This is the MW flow on end *a* of the DC line *d* at time *t*. The sign convention is that flow from the DC line into the AC system is considered negative.

$dcw_{d,b}^{t}$ This is the MW flow on end *b* of the DC line *d* at time *t.* The sign convention is that flow from the DC line into the AC system is considered negative.

2.5.2. In its operation, *HVDC* Resource on both ends of a DC Link can act both as a generator and a *load*, with *HVDC* having three discrete state of operation: no-flow, flow in prevailing direction and flow in direction opposite to the prevailing direction. The MW schedules to the *HVDC* Resources are included in *Load* Balance of each of the electrical islands connected by DC Link. They are also included in *HVDC* flow equation that accounts for losses as described below.

2.5.3. A default DC loss percentage is used to obtain a simplified formulation of DC Link *load* balance.

When the flow is from end *b* to end *a*:

$$\mathrm{dcw_{d,b}^{t}} + \mathrm{dcw_{d,a}^{t}} - \mathrm{dcwlossp_{d,b,a}}/100 \cdot \left(\mathrm{dcw_{d,b}^{t}}\right) = 0$$

When the flow is from end *a* to end *b*:

$$\mathrm{dcw_{d,b}^{t}} + \mathrm{dcw_{d,a}^{t}} - \mathrm{dcwlossp_{d,b,a}}/100 \cdot \left(\mathrm{dcw_{d,a}^{t}}\right) = 0$$

Where:

$dcwlossp_{d,b,a}$ is the default loss percentage.

There are no slack variables associated with above equations. Note that $dcw_{d,a}^{t}$ and $dcw_{d,b}^{t}$ variables are unbounded, but subject to DC MW Flow *constraints*. In case of zero losses, above equations essentially state that the DC Link transfer at End *b* is the same as transfer at End *a* by absolute value, but with opposite sign.

If the presence of DC link is the only electrical connection between AC *networks* at End *a* and End *b*, then those *networks* are considered to be separate AC islands, so the network injections at one island do not have shift factors with respect to the AC flow *constraints* in another island.

Directional HVDC Limit

2.5.4. Directional flow *constraints* flow on DC line to be between minimum and maximum flow limit for each direction (if the flow is non zero).

When the flow is from End *a* to End *b*, the constraint is:

$$\underline{HVDC_{d,a}^{t}} \le \ dcw_{d,a}^{t} \le \overline{HVDC_{d,a}^{t}}$$

When the flow is from End *b* to End *a*, the constraint is:

$$\underline{HVDC_{d,b}^{t}} \le \ -dcw_{d,a}^{t} \le \overline{HVDC_{d,b}^{t}}$$

Where:

$\overline{HVDC_{d,a}^{t}}$ and $\underline{HVDC_{d,a}^{t}}$ are maximum and minimum MW flow limit (positive values) when flow is from *a* to *b*

$\overline{HVDC_{d,b}^{t}}$ and $\underline{HVDC_{d,b}^{t}}$ are maximum and minimum MW flow limit (positive values) when flow is from *b* to *a*

2.5.5. Additional binary variables are introduced to enforce directional limits. One binary variable is used to model flow from End *a* to End *b* and another binary variable is introduced to model flow from End *b* to End *a*. When DC transfer variable $dcw_{d,a}^{t}$ is positive, then the binary variable $dcd_{d,a}^{t}$ has to be one and the binary variable $dcd_{d,b}^{t}$ has to be zero. Analogously in case when $dcw_{d,a}^{t}$ is negative. In case that $dcw_{d,a}^{t}$ is itself zero, both binary variables have to be zero as well. The upper and lower directional limit on *HVDC* flow can be formulated as:

$$dcw_{d,a}^{t} \le \overline{HVDC_{d,a}^{t}} * dcd_{d,a}^{t} - \underline{HVDC_{d,b}^{t}} * dcd_{d,b}^{t}$$
$$dcw_{d,a}^{t} \ge \underline{HVDC_{d,a}^{t}} * dcd_{d,a}^{t} - \overline{HVDC_{d,b}^{t}} * dcd_{d,b}^{t}$$
$$dcd_{d,a}^{t} + dcd_{d,b}^{t} \le 1$$

Where:

$dcd_{d,a}^{t}$ is a binary variable determining whether the MW flow is from end *a* to end *b* at time interval *t*
$dcd_{d,b}^{t}$ is a binary variable determining whether the MW flow is from end *b* to end *a* at time interval *t*

2.5.6. The *HVDC* Flow limit equations are soft *constraints* and include slack variables for limit violation, both for minimum and maximum flow limit, and in both directions.

Minimum time needed for HVDC change of flow

2.5.7. Additional constraint applicable to *HVDC* line is the “change of flow direction” constraint. It is described by the minimum time that has to lapse before a power flow on DC line can flow in the opposite direction. Constraint is modeled as form of a minimum down time constraint, i.e. the minimum time *HVDC* Line has to spend in zero flow condition.

2.5.8. The constraint is enforced by the following equations:

$$\sum_{t=t1}^{t1+T_d^{MIN}} dct_{d,a}^{t} \geq T_d^{MIN}$$

$$dct_{d,a}^{t} = 1 - (dcd_{d,a}^{t} + dcd_{d,b}^{t})$$

That are effective for every interval *t1* where the flow changed to zero from being non-zero; i.e.

$$dct_{d,a}^{t1} - dct_{d,a}^{t1-1} = 1$$

Where:

$dct_{d,a}^{t}$ is a helper variable showing that the flow on the DC line is zero at time interval *t*
T_d^{MIN} is the minimum time before the DC line flow can be reversed

2.5.9. In addition to above equations there are boundary conditions considering past as follows:

$dct_{d,a}^{t}$ Variable has counter reflecting the initial condition, i.e. if there is a change of flow to zero from non-zero that occurred in the past, that interval is recorded and the counter is incremented each *real time dispatch* run, while in each subsequent *real time dispatch* run the following is enforced:

$$dct_{d,a}^{t} = 1 \ \forall \ t \leq MAX(0, T_d^{MIN} - t_0)$$

Where:

t_0 is the number of intervals since the flow was last changed from non-zero to zero in the past *real time dispatch* runs.

2.5.10. The change of flow *constraints* are hard *constraints* and cannot be violated in the model. In the case when the *HVDC* line flow direction change is pre-scheduled, the minimum switching time is modified to comply with the schedule (i.e. the line flow direction change schedule is always considered to be feasible).

SECTION 3 BID/OFFER RELATED CONSTRAINTS

The electric *energy* related products are provided from physical resources with limited capacities. In addition to limited amount of available products separately, the capacity limits for resources providing multiple products are included into optimization model. Therefore, the model includes the following limitations for each physical resource and for each time interval:

3.1. Energy Dispatch Limits

3.1.1. Resource *energy* award has to be within the economic limits (*Energy offer/bid* limits).

$$\underline{En}_{res}^{t} \leq En_{res}^{t} \leq \overline{En}_{res}^{t} \quad , \quad res \in G, L$$ Resource *offer/bid* limits

3.2. Regulating Reserve Limits

3.2.1. Regulation Reserve awards (allotments) are less than the upper *offer* limit and are less than the *reserve* ramping capability (the regulation reserve ramping time multiplied by the regulation *ramp rate*).

$$Reg_{unit}^{Raise;t} \leq \min\{\overline{Reg}_{unit}^{Raise;t} \; ; RR_{unit}^{RegUp} \cdot T_{dom}^{Reg} \}$$

$$Reg_{unit}^{Lower;t} \leq \min\{\overline{Reg}_{unit}^{Lower;t} \; ; RR_{unit}^{RegDn} \cdot T_{dom}^{Reg} \}$$

3.3. Contingency Reserve Limits

3.3.1. Contingency Reserve awards (allotments) are less than the upper *offer* limit and are less than the contingency reserve ramping capability (contingency reserve ramping time multiplied by the *reserve ramp rate*).

$$Res_{unit}^{t} \leq \min\{\overline{Res}_{unit}^{t} \; ; RR_{unit}^{Res} \cdot T_{dom}^{Res} \}$$

3.3.2. The *reserve ramp rate* is submitted as part of the *offer*, while *reserve* ramping time is the time required by service definition to reach full response.

3.4. Tie-Break Processing

3.4.1. For scenario of tie-breaking among *offers* for the same service or among *bids* for the same service, the soft ‘tie breaking’ constraint will be introduced that is enforcing pro-rata equality of awarded block MW quantities. Constraint enforces that the difference between awards for two equally priced blocks, pro-rated by their maximum value, should be equal to zero. As this is equality constraint, two single segment slack variables will be introduced per constraint. For a group of *N* identified blocks that are tied at the same price (from N *offers*, where N is expected to be 2 for most practical cases), and have to be subject to tie break processing, a set of N-1 equation will be written as:

$$\frac{BQ_{k,1}^{i}}{\overline{BQ}_{k,1}^{j}} - \frac{BQ_{k,2}^{j}}{\overline{BQ}_{k,2}^{j}} + \overline{Slack}_{TB,k}^{1} - \underline{Slack}_{TB,k}^{1} = 0$$

3.4.2. Where $BQ_{k,1}^{i}$, $BQ_{k,2}^{j}$ are ith and jth block quantities from first and second *offer* within the group, and $\overline{BQ}_{k,1}^{i}$, $\overline{BQ}_{k,2}^{j}$ are respective block sizes.

$$\frac{BQ_{k,2}^{m}}{\overline{BQ}_{k,2}^{m}} - \frac{BQ_{k,3}^{l}}{\overline{BQ}_{k,3}^{l}} + \overline{Slack}_{TB,k}^{2} - \underline{Slack}_{TB,k}^{2} = 0$$

$$\dots$$

$$\frac{BQ_{k,n-1}^{u}}{\overline{BQ}_{k,n-1}^{u}} - \frac{BQ_{k,n}^{v}}{\overline{BQ}_{k,n}^{v}} + \overline{Slack}_{TB,k}^{n-1} - \underline{Slack}_{TB,k}^{n-1} = 0$$

3.4.3. The slack variables introduced will contribute to the Objective under very low penalty prices (comparing to other penalties), so the constraint can be violated by any other constraint. Analogous equations are written for equally priced *bid* block quantities. These *constraints* can be applied for *energy bid*/*offer* tie-breaking as well as for *reserve bid* tie breaking.

3.4.4. In addition, the tie breaking process will be applied to self-scheduled *generation* (e.g. Tie Breaking of self- scheduled generators in cases of *network* limitation).

3.4.5. To reflect the actual economics of the *market dispatch optimization model*, the “economic” tie breaking will be applied in the model only to resources with the same loss sensitivities (loss penalty factors). Since tie-breaking equations are part of the integral problem formulation, and not post processing, tie breaking solution reflects all the economic characteristics of the model, i.e. congestion costs or AS opportunity costs.

3.4.6. Tie breaking is also applied for *self-scheduled energy* resources in case of curtailment of projected schedule. For this scenario, *constraint violation coefficient* values will be defined for violation of *self-scheduled energy* dispatch in scheduling run. Then in pricing run setup, prices and *self-scheduled energy dispatch schedule* constraint will be set analogously to other soft *constraints*. Pro rata remains the same as for economic *offers*.

3.4.7. There is exception to economic tie breaking rules in curtailment of *self-scheduled energy* dispatch resources, where tie breaking in certain scenarios is performed so that curtailment is performed proportionally to submitted (or forecasted) self-schedules. For additional details please see Appendix A.3.

3.4.8. In case of tie between a *demand bid* and a generator *offer* (with same loss sensitivities), there is no pro-rating, instead the *load* served is maximized by addition of small “incentive term” making the combined *load-generation* award net positive to the objective.

SECTION 4 GENERATING/LOAD RESOURCE CONSTRAINTS

4.1. Energy Capacity Limits

4.1.1. When there is no *reserve offer* from the unit, e*nergy dispatch* has to be within unit operating limits:

$$EnL_{unit}^{t} \le En_{unit}^{t} \le EnH_{unit}^{t}$$

4.2. Constant Ramping Limits

4.2.1. The ramping capabilities of *generation* and *load* units are expressed as constant values of maximal Up and Down *Ramp Rates* over the full range of the resource power output. The Up and Down *Ramp Rate* Limits are calculated as a product of maximal Up and Down *Ramp rate* values and the *energy* ramping time domain:

$$RRL_{unit}^{Up} = RR_{unit}^{Up} \cdot T_{dom}^{En}; \quad RRL_{unit}^{Dn} = RR_{unit}^{Dn} \cdot T_{dom}^{En}; \quad unit \in G$$
$$RRL_{load}^{Up} = RR_{load}^{Up} \cdot T_{dom}^{En}; \quad RRL_{load}^{Dn} = RR_{load}^{Dn} \cdot T_{dom}^{En}; \quad load \in L\ .$$

4.2.2. For each *generation* and *load* unit and each time interval the following *energy* Up and Down *Ramp rate* Limits are posted:

$$-RRL_{unit}^{Dn} \le En_{unit}^{t} - En_{unit}^{t-1} \le RRL_{unit}^{Up}; \quad unit \in G; t \in T$$
$$-RRL_{load}^{Dn} \le En_{load}^{t} - En_{load}^{t-1} \le RRL_{load}^{Up}; \quad load \in L; t \in T\ .$$

4.2.3. The *energy* ramping time domain is dependent on the length of time interval.

4.3. Reserve Model

4.3.1. Core parts of the *Reserve* model are:

a. *Reserve* capacity limits
b. *Reserve* ramping
c. Combined *Energy* and *reserve* capacity limits
d. Combined *Energy* and *reserve* ramping
e. Independent model for Raise and Lower service in each *reserve* category

Resource Reserve capacity limits

4.3.2. In addition to limits imposed by *reserve offer* limits, there are physical unit limits that affect *reserve* award. One example is for fast and slow *reserves* limitation by Governor response. While Governor response also depends on frequency deviation, it is usually one curve provided for Market purpose, where response is given as function of *energy* output only. Typical Governor response curve is provided below:

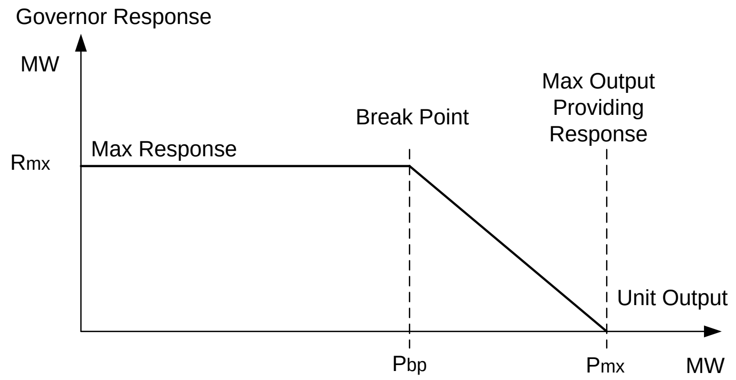

Figure 2: Governor *n* second raise droop characteristic

4.3.3. Each two-piece characteristic comprises:

a. maximum response amount which applies between zero *energy dispatch* and the contracted *energy dispatch* breakpoint and;
b. above the *energy dispatch* breakpoint there is linear decrease in response amount from the contracted maximum response amount down to zero maximum response at the maximum *energy* capacity.

4.3.4. The mathematical formulation using the variable designation from Figure 2 are as follows:

$$Res_{unit}^{t} = R_{mx} * (P_{mx} - P^{t})/(P_{mx} - P_{bp}) \ \forall \ P \geq P_{bp}$$
$$Res_{\mathrm{unit}}^{\mathrm{t}} = \mathrm{P_{mx}} \ \forall \ \mathrm{P} < P_{\mathrm{bp}}$$

4.3.5. In addition to maximum quantity, contracted generators might be subject to mandatory governor response, which is modeled as *reserve* self-schedule and protected with penalty in Scheduling Run (i.e. treated as price taker). Such self-schedule also contributes to regional *reserve requirements*.

Resource AS ramping limits

4.3.6. The individual *reserve* ramping constraint can be posted for each resource and each time interval. These *constraints* are expressed in time domain as follows (equation is provided for Regulation Raise, but analogous equation applies for each *reserve*:

$$\frac{Reg_{unit}^{Raise;t}}{RR_{unit}^{RegUp}} \leq T^{AS}; \quad unit \in G; t \in T$$

meaning that the *Reserve* ramping cannot exceed the specified *reserve* ramping (default 5 minutes).

Resource Combined Energy and Reserve Capacity Limits

4.3.7. Multiple market services can be provided by the same resource at the same time, but the total resource capacity is limited. For example, the capacity range of online *generation* resources can be used for *energy*, regulation raise capacity and contingency *reserve*.

4.3.8. The capacity range binding *energy* and *reserve* depends on the services involved. For example, for combined *Energy* and Regulating reserves, the regulating range is binding.

$$En_{unit}^{t} + RegRaise_{unit}^{t} \leq RH_{unit}^{t}$$

$$En_{unit}^{t} - RegLower_{unit}^{t} \geq RL_{unit}^{t}$$

4.3.9. In a scenario when regulating limits are not separately registered for a resource, the operating limits are used instead of regulating in the above equations.

4.3.10. For combined *Energy* and Contingency (Frequency Response) Service, the sum of the scheduled *energy* and the scheduled FCAS response ($PSRaise_{unit}^{t}$) must be less than or equal to the Governor Droop Raise Capacity $\left(GDRH_{unit}^{t}\right)$ of that unit for each of the services:

$$En_{unit}^{t} + PSRaise_{unit}^{t} \leq GDRH_{unit}^{t}$$

4.3.11. Analogous capacity limits are posted on *load* entities. For example of Contingency reserve:

$$En_{load}^{t} - SRes_{load}^{t} \geq EL_{load}^{t}$$

Resource *Combined Energy and Reserve Ramping*[40]

4.3.12. If the *reserve* awards were dispatched for *contingency,* they would be converted into *energy* that needs to ramp, thus taking away ramping capability of dispatched *energy* award. The *energy* ramping period is the same as *dispatch interval*, so if it was fully utilized for *energy* ramping, there would be no room for additional *energy* ramping needed if *reserve* was activated. Therefore the *reserve* awards have to be taken into account in *energy* ramping model. *Energy* ramping capacity based on *energy ramp rate* is adjusted to address the impact from *reserve* awards. The upward and downward ramping equations can be expressed as:

$$P_i(t) - P_i(t-1) \leq RLU_i^{En}(t) - ASUp_i(t)$$

$$P_i(t-1) - P_i(t) \leq RLD_i^{En}(t) - ASDn_i(t)$$

where: ASUp and ASDn is upward/downward *reserve* impact to *energy* ramping capacity.

[40] Example is provided in Appendix A.3

4.4. Other Operational Modes of Generators, Loads or Similar Facilities

4.4.1. Hybrid resources or other operational modes of generators, loads, or similar facilities include hydro pump storage and non-generating resources (NGR)[41] like batteries, flywheel, compressed air facilities, and other forms of primary energy storage.

4.4.2. Potential models for the treatment of these resources may incorporate variability of both supply offers and demand bids for more optimal economic results.

SECTION 5 MARKET CLEARING PRICES

5.1. The SCDD model calculates constraint shadow costs as a byproduct of the optimization process. Those shadow costs are directly taken from optimization solution constraint dual variables and reflect change in the objective function due to incremental *constraint* relaxation.

5.2. These shadow costs indicate the effect on the objective function of the various *constraints*. The shadow costs related to the system power balance represent the marginal *energy* costs and refer to a location where the market requirement for *energy* is posted, i.e. to the central market place. These shadow costs present an equivalent to System marginal cost in classic unit commitment formulation.

5.3. The Marginal *Energy* Cost for each interval t is determined as shadow cost (λ_{En}^{t}) for *energy* balance *constraints* and it is the uniform price component for all market participants and pricing locations.

5.4. The Marginal Clearing Price is calculated as the As-*Bid* cost of the Marginal Resource.

SECTION 6 NODAL ENERGY DISPATCH PRICES (LOCATIONAL MARGINAL PRICES)

6.1. *Load* and generating unit contributions to the system power balance differ with respect to *network energy* losses and eventual transmission congestion. The *energy* prices are differentiated according to specific conditions of actual power injections and withdrawals at market participant locations. In general, *energy* prices are different at each *network* node, i.e. they present *nodal energy dispatch prices* or Locational Marginal Prices (LMP). In a widely accepted formulation, the *energy* LMP present the marginal cost of serving the incremental *load* at the price location by all available resources of the system.

6.2. The LMP is used to settle the market and is calculated in each run by SCDD. The LMP is calculated for each generator and participating *load*.

[41] NGR is a device that has a continuous operating range from a negative to a positive power injection; i.e., it can operate continuously as either consumes load or provides power, and it can seamlessly switch between generating and consuming electrical energy. NGR functions like a generation resource and can provide energy and AS services.

6.3. To support the settlement, the *energy* LMP is calculated at all pricing locations. Each pricing location corresponds to a single market *network* node where the generator or *load* resources are connected. Pricing locations can also include buses with no resources.

6.4. The Locational Marginal Prices for *energy* are calculated respecting *network* losses and eventual transmission congestion:

$$LMP^t_{En;node} = \lambda^t_{En} / pf^t_{node} + \sum_{line \in N} SF_{line;node} \cdot TSC^t_{line} \; ; t \in T; node \in G \cup L$$

6.5. Locational Marginal Prices are the same for *generation* and *load* entities at the same *network* node. The Locational Marginal Prices for *energy* consist of several components:

$LMP^t_{En;node} =$	λ^t_{En}	- Marginal *Energy* Cost
	$+\lambda^t_{En} \cdot (1 - pf^t_{node}) / pf^t_{node}$	- Price for marginal *network energy* losses
	$+\sum_{line \in N} SF_{line;node} \cdot TSC^t_{line}$	- Price for marginal *network congestion*.

SECTION 7 RESERVE PRICING

7.1. Similar to *energy* pricing, the marginal cost approach is used for ancillary services pricing. The regional *reserve requirements* are posted as minimum and maximum regional limits. The shadow costs ($\lambda^{AS;t}_{ASReg}$) for posted regional *reserve requirements* present the corresponding shadow costs that are calculated as a by-product of the optimization process. These shadow costs present ancillary service Regional Clearing Prices for each ancillary service. These Regional Clearing Prices are used for *reserve* pricing purposes.

7.2. The regional *reserve shadow price* can be expressed the sum of "Reserve Clearing Price" ($ASMP^{AS;t}_{ASReg}$) and the "Opportunity Cost" $\left(LOC^{AS;t}_{ASReg}\right)$ as:

$$\lambda^{AS;t}_{ASReg} = ASMP^{AS;t}_{ASReg} + LOC^{AS;t}_{AS\,Reg}$$

7.3. The "Reserve Clearing Price" is calculated as part of SCDD solution post-processing, as the *reserve offer* price associated with the marginal block that was cleared in the market. Once obtained, then the "Opportunity Cost" is calculated as the difference between the regional *reserve requirement* constraint *shadow price* and the "Reserve Clearing Price".

Resource Reserve Prices

7.4. The Resource Reserve Marginal Prices are calculated as summation of individual regional prices.

7.5. In general, each generating unit and *load* entity can have a different Reserve Marginal Price.

APPENDIX A.1 - MATHEMATICAL NOTATION

- Offer Costs

$C_{unit}^{En;t}(\cdot)$	is unit *energy generation* cost at time interval *t*
$C_{unit}^{RegRaise;t}(\cdot)$	is unit Regulation Raise cost at time interval *t*
$C_{unit}^{RegLower;t}(\cdot)$	is unit Regulation Lower cost at time interval *t*
$C_{unit}^{FFCS;t}(\cdot)$	is unit Fast Frequency Control Services cost at time interval *t*
$C_{load}^{curt}(\cdot)$	is *load* curtailment cost
$C_{load}^{En;t}(\cdot)$	is *load energy* cost at time interval *t*
$C_{constr}^{vio}(\cdot)$	is *constraint* violation cost at time interval *t*

- Energy Requirements

En_{req}^{t}	is market *energy* requirement at time interval *t*. This term refers to total unscheduled (forecasted) *load*
ΔEn_{req}^{t}	is change in market *energy* requirement at time interval *t*

- Reserve Requirements

$\underline{Reg}_{ASreq}^{Raise;t}$	is Regulation Raise minimum requirement for reserve region at time interval t
$\overline{Reg}_{ASreq}^{Lower;t}$	is Regulation Lower maximum requirement for *reserve region* at time interval *t*
$\underline{Reg}_{ASreq}^{Lower;t}$	is Regulation Lower minimum requirement for *reserve region* at time interval *t*
$\underline{Res}_{ASreq}^{t}$	is Frequency Control minimum requirement for *reserve region* at time interval *t*

- Product Quantities

En_{unit}^{t}	is unit *energy generation* at time interval *t*
En_{load}^{t}	is *load energy* consumption at time interval *t*
$Reg_{unit}^{Raise;t}$	is unit Regulation Raise capacity at time interval *t*
$Reg_{unit}^{Lower;t}$	is unit Regulation Lower capacity at time interval *t*
Res_{unit}^{t}	is unit Reserve at time interval *t*
$FFCS_{unit}^{t}$	is unit Fast Frequency Control Services quantity at time interval *t*
CV_{constr}^{t}	is *constraint* violation amount at time interval *t*

- Offer/Bid Limits

$\overline{En}_{res}^{t}$ is unit/load maximal *energy generation* at time interval *t*

$\underline{En}_{res}^{t}$ is unit/load minimal *energy generation* at time interval *t*

$\overline{Reg}_{unit}^{Raise;t}$ is unit maximal Regulation Raise capacity at time interval *t*

$\overline{Reg}_{unit}^{Lower;t}$ is unit maximal Regulation Lower capacity at time interval *t*

$\overline{Res}_{unit}^{t}$ is unit maximal contingency *reserve* at time interval *t*

- Resource Capacities

EnH_{unit}^{t} is unit *energy generation* high limit at time interval *t*

EnL_{unit}^{t} is unit *energy generation* low limit at time interval *t*

$\overline{En}_{unit}^{T}$ is unit *energy generation* maximum over time horizon *T*

EnH_{load}^{t} is *load energy* consumption high limit at time interval *t*

EnL_{load}^{t} is *load energy* consumption low limit at time interval *t*

$RegH_{unit}^{t}$ is unit regulation high limit at time interval *t*

$RegL_{unit}^{t}$ is unit regulation low limit at time interval *t*

$RRL_{unit/load}^{Up}$ is ramp-limited maximum increase of additional energy schedule for reserve

$RRL_{unit/load}^{Dn}$ is ramp-limited maximum decrease of additional energy schedule for reserve

- Ramping Rates

RR_{unit}^{Up} is unit *energy* Up *ramp rate*

RR_{unit}^{Dn} is unit *energy* Down *ramp rate*

RR_{unit}^{RegUp} is unit Regulation Raise *ramp rate*

RR_{unit}^{RegDn} is unit Regulation Lower *ramp rate*

RR_{unit}^{Res} is unit Reserve *ramp rate*

RR_{load}^{Up} is *load energy* Up *ramp rate*

RR_{load}^{Dn} is *load energy* Down *ramp rate*

- Time Domains

T_{dom}^{En} is *energy* ramping time domain

T_{dom}^{Reg} is regulation ramping time domain

T_{dom}^{Res} is *reserve* ramping Up time

T_{dom}^{En} is *energy* ramping time domain

T^{AS} is Ancillary Service ramping time

- Network Loss Model

En^{t}_{loss}	are *network energy* losses at time interval *t*
$En^{base;t}_{loss}$	are base *network energy* losses at time interval *t*
ΔEn^{t}_{loss}	is change of *network energy* losses at time interval *t*
$En^{base;t}_{unit/load}$	is unit/*load* base operating point at time interval *t*
α^{t}_{node}	is loss sensitivity factor for *node* or loss sensitivity to the change of *generation* in the *node* at time interval *t*
$pf^{t}_{unit/load}$	is loss penalty factor for *unit/load* at time interval *t*

- Transmission System Model

P^{t}_{line}	is line actual power flow at time interval *t*
SF^{node}_{line}	is shift factor for transmission *line* and *network node*
$P^{base;t}_{line}$	is line base power flow at time interval *t*
P^{t}_{node}	is actual *generation*/consumption at time interval *t*
$P^{base,t}_{node}$	is *unit*/*load* base *generation*/consumption at time interval *t*
$\underline{P}^{t}_{line}$	is line minimal power flow limit at time interval *t*
$\overline{P}^{t}_{line}$	is line maximal power flow limit at time interval *t*
$line \in N$	is the set of *transmission lines*
$node \in NN$	is the set of *network nodes*

- Commodity Prices

$LMP^{En;t}_{node}$	is Locational Marginal Price for *energy* at *network node* at time interval *t*
$LMP^{En;t}_{Pnode}$	is Locational Marginal Price for *energy* at Pricing Location at time interval *t*
CV^{t}_{constr}	is Constraint Violation for constraint *constr* at time interval *t*

- Market Constituents

$unit \in G$	is the set of online generating units
$load \in L$	is the set of dispatchable *loads*

- Market Timeline

$t \in T$	is scheduling time horizon *T* divided into time intervals *t*
Δ_t	is the duration of the time interval *t*
ρ_t	is the duration of the time interval *t* as a fraction of an hour.

APPENDIX A.2 - COMBINED ENERGY AND RESERVE RAMPING EXAMPLE

To put a numerical example for equations for Resource Combined *Energy* and Reserve Ramping under Section 4.3, let us say that a unit has maximum ramp up rate of 6 MW per minute; that would mean the unit can ramp its power output at maximum 30 MW up from its initial condition (5 minutes times 6 MW per minute equals 30 MW, that is the maximum amount for $RLU_i^{En}(t)$ value).

Let us say that initial condition P(t-1) is 50 MW. In case when there are no *reserve* awards, unit can reach 80 MW at the end of *dispatch interval.*

Now let us assume that the unit for the same interval is awarded 10 MW of Regulation Raise.

In case the unit is called to provide Regulation Raise service (*reserve* award is activated into *energy*), then the unit has to ramp up those ten MWs during the interval, and that ramping comes in addition to ramping of unit's *energy* award.

Model will ensure that *energy* schedule P(t) is no more than the 50 MW (initial condition) + 30 MW (*energy* ramping) – 10 MW (regulation award) for the end of the interval.

So in case where this unit is called for delivery of 10 MW of Regulation Raise award, unit would be able to reach new set point set by *AGC.*

In an example, if a unit is awarded by Market at 65 MW of *energy* for particular interval, and then 10 MW of Regulation Raise, then if the Regulation Raise is activated by the *System Operator*, it would be possible for unit to ramp from its initial condition to the new set point of 65 MW +10 MW = 75 MW, as ramping requirement for the interval of 75 MW – 50 MW (initial condition) = 25 MW, that the unit can ramp in less than five minutes (with max ramping capability of 30 MW over the length of *Dispatch Interval*).

APPENDIX A.3 - SELF-SCHEDULED ENERGY DISPATCH CURTAILMENT

Per current *System Operator* operational practice, in a scenario where a group of *self-scheduled energy generating units* is self-scheduled at multiple points of a multi-leg radial connection, and the curtailment has to be performed for the group, there is specific rule for curtailing the individual units. In such a case, the units are curtailed proportionally to their self-scheduled MW, regardless of economics. To illustrate that practice, example for *self-scheduled energy* is provided below.

In the example shown in Figure 3 below, units D and E have the lowest priority and will be cut first. In this example the Shift Factors for Generators D and E, with respect to the flow on line 2 are assumed to be 1, so the total curtailed MW amount (5 MW) is equal to the MW flow relief (5 MW) of the line 2. This curtailment of 5 MW is distributed among units D and E proportionally to their self-scheduled MWs,, i.e. unit D is getting 40% of the total curtailment, while unit E is getting 60% of the relief.

It is important to note the assumptions for this processing:

- Processing only applies to units that are self-scheduled
- Units subject to this processing are having the same priority

- Units are not subject to ramping *constraints* (being self-scheduled, no ramping *constraints* are applicable per convention)
- Economic impact is to be disregarded (i.e. economical impact of incremental losses or shift factors)
- Minimum operating limit (Pmin) of the units subject to this processing is considered to be zero unless registration data is non-zero. If the *minimum stable load* (Pmin) is greater than zero, then the pro-rata adjustments only applies to Nominated quantities above the Pmin. For example, if the Nomination is 100 MW and the unit Registered Pmin is 40 MW, the amount subject to pro-rata curtailment is 60 MW and that is the coefficient used in the curtailment pro-rata processing (not the Nominated 100 MW).

Generator	Gen Type	Priority #	Segment 1		Segment 2		Segment 3		Segment 4	
			P1	Q1	P2	Q2	P3	Q3	P4	Q4
GEN_A	Scheduled	--	NA	10	-100	20	150	35		
GEN_B	Self-Scheduled	1	NA	15						
GEN_C	Scheduled	--	NA	150	0	265				
GEN_D	Self-Scheduled	2	NA	20						
GEN_E	Self-Scheduled	2	NA	30						

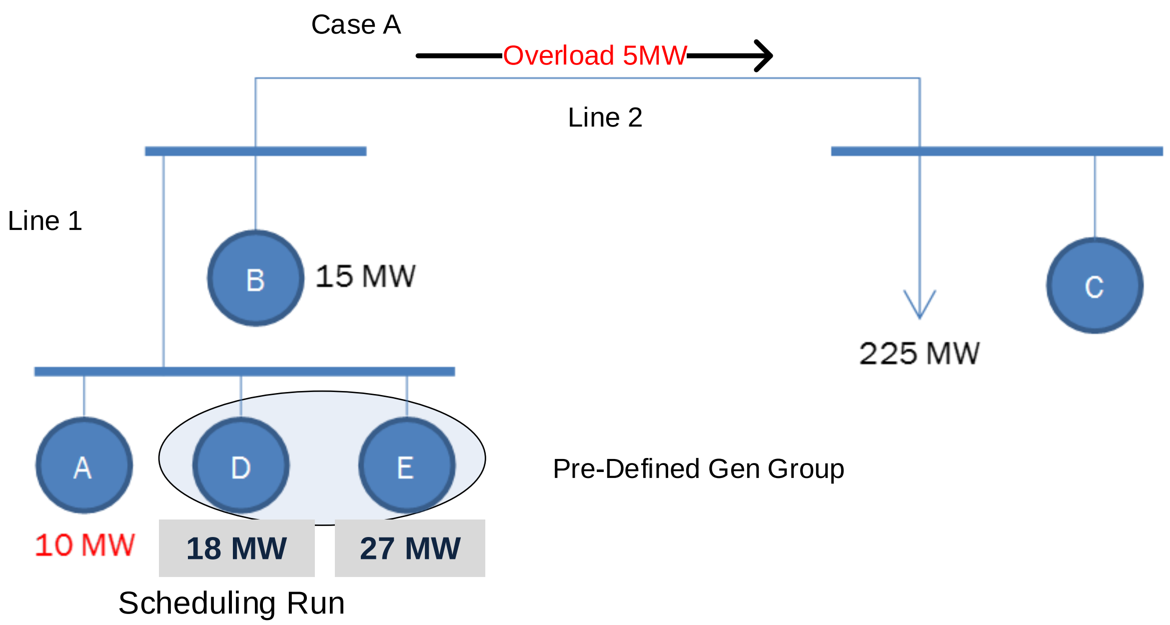

Figure 3: Example of pro-rata curtailment of electrically identical units

In order to provide such functionality, and disregard the economics of the case, the following constraint can be added to the model:

- (En(E,t)-Pmin(E,t)/(Pnom(E,t)- Pmin(E,t)) = (En(D,t)- Pmin(D,t))/(Pnom(D,t)-Pmin(D,t));

Where *En(D,t),Pmin(D,t), Pnom(D,t)* are awarded MW, Pmin and Nominated (self scheduled) MW respectively, for unit *D* in time interval *t*.

While the constraint seems trivial, it will be written only for units that are satisfying the above assumptions, plus the additional assumptions as follows:

- Units have to be defined to belong to a special "pro-rata group"; each unit within the group is subject to prorata processing that links units within the group with the equations above.
- "Pro rata" Groups are defined ahead of time. There can be many groups, and many units within each group, but one unit can belong to only one "pro-rata group".

Such approach would also satisfy scenario as listed in Figure 4 below:

Generator	Gen Type	Priority #	Segment 1		Segment 2		Segment 3		Segment 4	
			P1	Q1	P2	Q2	P3	Q3	P4	Q4
GEN_A	Scheduled	—	NA	10	-100	20	150	35		
GEN_B	Self-Scheduled	2	NA	15						
GEN_C	Scheduled	—	NA	150	0	265				
GEN_D	Self-Scheduled	1	NA	20						
GEN_E	Self-Scheduled	2	NA	30						

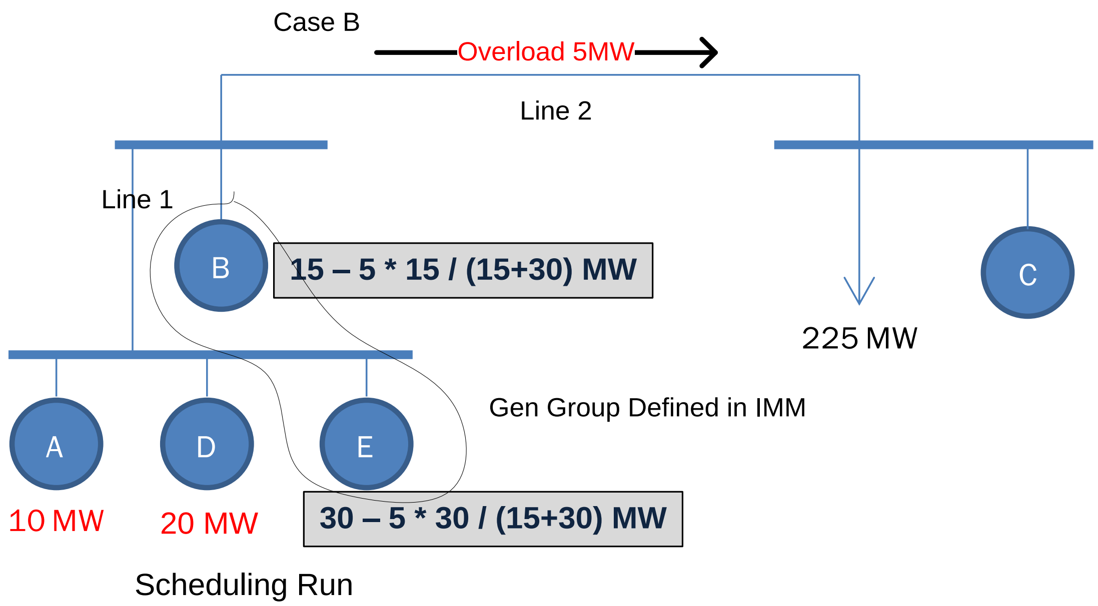

Figure 4: Example of pro-rata curtailment of electrically different units

However, the approach described so far might not be suitable for scenario as listed in Figure 5. For this scenario the pro-rate processing should not be applied (i.e. if the shift factors of the units within the group do not have the same sign).

Generator	Gen Type	Priority #	Segment 1		Segment 2		Segment 3		Segment 4	
			P1	Q1	P2	Q2	P3	Q3	P4	Q4
GEN_A	Scheduled	—	NA	10	-100	20	150	35		
GEN_B	Self-Scheduled	2	NA	15						
GEN_C	Scheduled	—	NA	150	0	265				
GEN_D	Self-Scheduled	1	NA	20						
GEN_E	Self-Scheduled	2	NA	30						

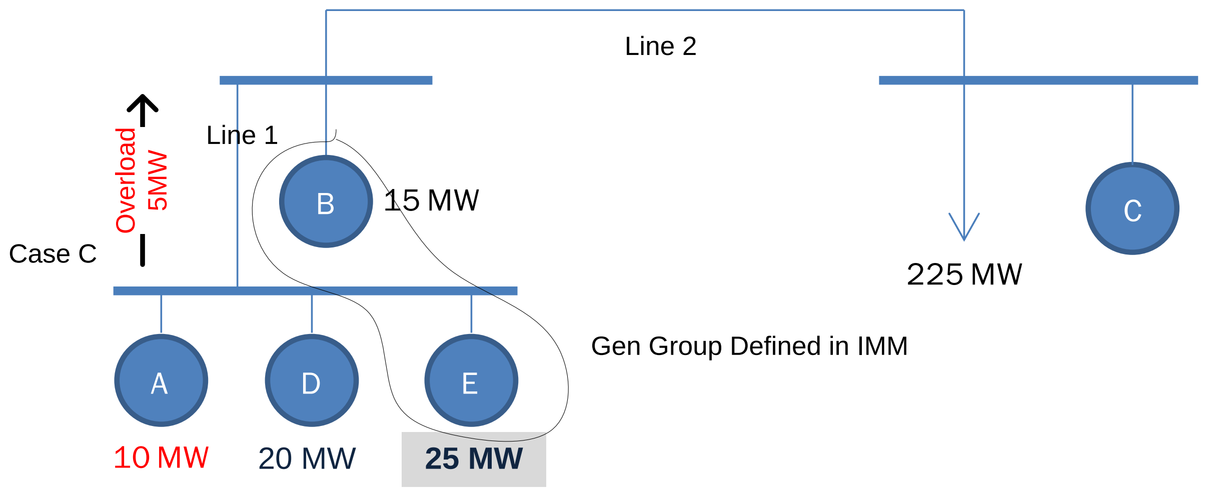

Figure 5: Example of pro-rata curtailment of electrically different units with shift factors of different sign

The approach would also not be suitable for scenario that would involve congestion both on lines 1 and 2 at the same time.

Under such scenarios, where the shift factors of the units within the group are of different sign with respect to a *network constraint,* only the units with same sign shift factors (those providing counter-flow to the congestion) will be subject to pro-rata curtailment.

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.

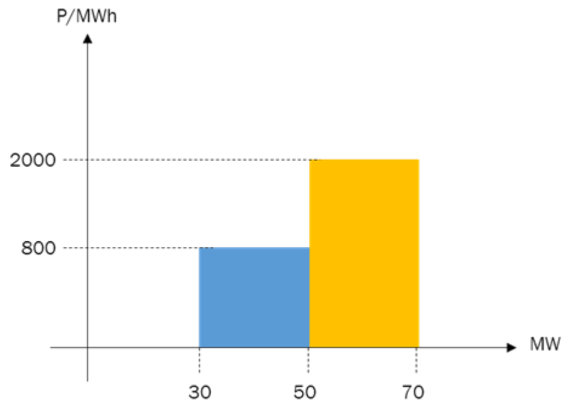

Figure 6. Generator A Price Curve

The price curve of Gen B is shown below.

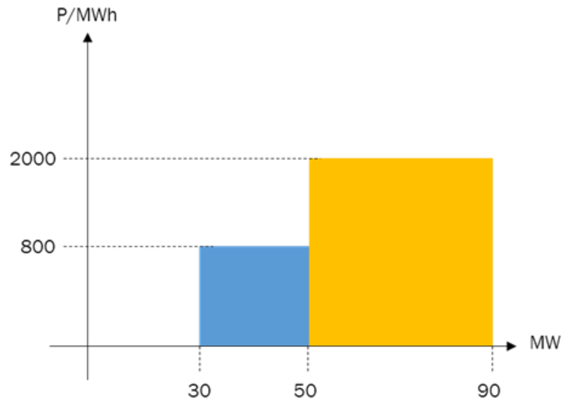

Figure 7. Generator B Price Curve

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 – Cost Recovery for Raise Contingency Reserves

As provided in Section 8.2.3, the *reserve* costs for contingency service shall be allocated among *generators* based on 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 8. Sample Representation for Cost Recovery for Raise Contingency Reserves

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 among 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 among 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.

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

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

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

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

Based on *Figure 8*, the generator allocation for Common Block 4 is:

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

Suppose that the total reserve amount to be paid for certain dispatch interval "i" is P30,000, then the reserve cost attributable to GEN D is:

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

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 8*), then the reserve cost attributable to GEN C is:

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

In the same manner, GEN B will pay P7,800 while GEN A will pay P18,600.

Appendix D - Provisions Prior to Interconnection of Mindanao

1.0 SCOPE

1.1 For this Appendix, the Luzon-Visayas settlement region shall refer to the combined Luzon and Visayas *grids* while the Mindanao settlement region shall refer to the Mindanao *grid*.

1.2 This appendix specifies the relevant calculations under the administered price determination methodology under Section 7 that will be performed per settlement region prior to the interconnection of the Mindanao *grid* to the Luzon and Visayas *grids*[42].

1.3 This appendix specifies the relevant calculations used to determine and allocate the *net settlement surplus* under Section 9 that will be performed per settlement region prior to the interconnection of the Mindanao *grid* to the Luzon and Visayas *grids*[43].

1.4 Other calculations provided in Section 7 or Section 9 that do not appear in this appendix will be applied as provided in those Sections even prior to the interconnection of the Mindanao *grid* to the Luzon and Visayas *grids*.

2.0 GENERATOR ENERGY ADMINISTERED PRICE

2.1 In reference to Section 7.2.6, when a *generator* resource does not have *final nodal energy dispatch prices* in the preceding four (4) most recent similar *trading days* and similar *dispatch intervals*, the *energy administered price* for that *generator* resource for a *dispatch interval* shall be calculated considering the positive *snapshot quantities* during the same *dispatch interval* of *generator* resources from the same settlement region (Luzon/Visayas or Mindanao) as the subject *generator* resource.

3.0 CUSTOMER ENERGY ADMINISTERED PRICE

3.1 In reference to Section 7.3.1, the *energy administered price* for all *customer* resources for a *dispatch interval* shall be calculated considering the positive *snapshot quantities* of all *generator* resources and *snapshot quantities* of all *customer* resources from the same settlement region (Luzon/Visayas or Mindanao).

[42] WESM Rules Clause 10.5.4
[43] WESM Rules Clause 10.5.2

4.0 CALCULATION OF NET SETTLEMENT SURPLUS

4.1 In reference to Section 9.2.1, the *net settlement surplus* amount shall be calculated per *dispatch interval* and settlement region (Luzon/Visayas or Mindanao) using the total amounts to be collected and paid from the same settlement region.

4.2 In reference to Section 9.4.2, the amount to be returned to a *Trading Participant* for a *settlement interval* shall be equal to the ratio of the *Trading Participant*'s loss and congestion charges to the total loss and congestion charges of all *Trading Participants* in the settlement region where the subject *Trading Participant* is located, multiplied by the total *net settlement surplus* amount for the same settlement region.

4.3 In reference to Section 9.4.2 (c), the line loss and congestion price for a *dispatch interval* for each resource shall consider the lowest aggregated marginal loss cost and marginal congestion cost within the same settlement region.

4.4 In reference to Section 9.4.3, when the *nodal energy dispatch prices* of all resources in a settlement region in a *dispatch 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 region for that *dispatch interval* shall be allocated to *customer* resources within the same settlement region on a pro-rata basis depending on each *customer* resource's share in the total *gross energy settlement quantity,* as determined under WESM Rules Clause 3.13.6*,* of all customer resources from that settlement region.