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Pricing and Cost Recovery Mechanism for Reserves in the Philippine WESM

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SUMMARY

Reserves are forms of ancillary services that are essential to the management of power system security. The provisions of reserves facilitate orderly trading in electricity and ensure that electricity supplies are at an acceptable quality.

As provided in the WESM Rules clause 3.3.4, when reasonably feasible, the Market Operator, in coordination with the System Operator, shall establish and administer a spot market for the purchase of certain reserve categories. The reserve categories that shall be traded in the WESM are regulating, contingency and dispatchable reserves as well as interruptible loads in lieu of reserves.

Prior to the commencement of the trading of reserves in the WESM, it is required that the methodology for determining reserves or costs as well as the mechanism for the allocation of the reserve cost recovery charges are approved by the Energy Regulatory Commission (the "ERC").

The Price Determination Methodology ("PDM") for the Philippine Wholesale Electricity Spot Market (the "WESM") was approved by the ERC on 20 June 2006 prior to the commencement of the WESM in Luzon. The approved PDM details the Market Dispatch Optimization Model (the "MDOM") which simultaneously determines dispatch targets for the end of a trading interval, reserve allocations for the trading interval, associated energy prices at all trading nodes in the power system and when applicable, reserve prices for all reserve regions as provided for under Section 3.6 of the WESM Rules. This simultaneous determination of dispatch targets, reserve allocations and the associated prices for energy and reserve is also known as the co-optimization of energy and reserves.

The Pricing and Cost Recovery Mechanism for Reserves in the WESM ("Reserve PCRM") contained in this document supplements the Price Determination Methodology for the WESM. It provides further details of the formulation and procedures by which reserve dispatch schedules and zonal reserve prices for each reserve region are calculated in the MDOM and which are already set forth in the approved WESM PDM. It provides for the formula and procedures for calculation of reserve trading amounts for reserve providers as well as for the calculation and allocation of the reserve cost recovery charges. It also sets forth the methodology for determining the administered reserve prices and reserve cost recovery charges that will be used for settlement of reserve transactions in cases of market suspension and intervention.

The approval of the ancillary services cost recovery mechanism is likewise the subject of an application filed by the National Transmission Corporation (the "Transco") with the ERC referred to as the Ancillary Services Cost Recovery Mechanism (the "AS-CRM"). The Transco application covers the charges that will be imposed for ancillary services prior to commencement of the WESM trading for reserves as well as for ancillary services that will not be traded in the WESM.

Once approved by the ERC, this Reserve PCRM will apply to all reserve categories traded in the WESM and will supersede, to this extent, the Transco Ancillary Services Cost Recovery Mechanism.

1. BACKGROUND

1.1. The establishment of the Philippine Wholesale Electricity Spot Market (the "WESM") is mandated by Republic Act No. 9136, otherwise known as the "Electric Power Industry Reform Act of 2001" (the "EPIRA"). Pursuant to the mandate of the EPIRA, the Department of Energy (the "DOE") jointly with the electric power industry participants formulated the detailed rules for the WESM (the "WESM Rules"). The WESM Rules were promulgated by the DOE on 28 June 2002. Among other things, the WESM Rules provided for the mechanism for determining the prices of electricity in the market not covered by bilateral contracts. As the WESM Rules provide for the trading of both energy and specific reserves categories in the WESM, the price determination methodology described therein covers both energy and reserves. The WESM price determination methodology is required by the EPIRA to be approved by the Energy Regulatory Commission (the "ERC").

1.2. On 20 June 2006, prior to the commencement of the WESM in Luzon, the WESM Price Determination Methodology ("PDM") was approved by the ERC. The approved PDM details the Market Dispatch Optimization Model ("MDOM") which simultaneously determines dispatch targets for the end of a trading interval, reserve allocations for the trading interval, associated energy prices at all trading nodes in the power system and reserve prices for all reserve regions as provided under Section 3.6 of the WESM Rules. This simultaneous determination of dispatch targets, reserve allocations and the associated prices for energy and reserve is also known as the co-optimization of energy and reserves.

1.3. The WESM commenced operations in the Luzon on 26 June 2006 following a declaration of market opening made by the DOE on 23 June 2006. Initially, only energy is being traded in the WESM. Trading of reserves will follow upon recommendation by the Market Operator and approval by the PEM Board.

1.4. The ERC has directed that prior to the commencement of the trading of reserves in the WESM the mechanism for pricing of the reserves transactions will be submitted to it for approval. The WESM Rules also provide that reserve cost recovery charges are approved by the ERC.[1] As stated earlier, the WESM PDM that has already been approved by the ERC provides for the pricing methodology for both energy and reserves.

The approval of the reserve cost recovery charges is likewise the subject of an application filed by the National Transmission Corporation with the ERC referred to as the Ancillary Services Cost Recovery Mechanism (the "AS-CRM"). The Transco application covers the charges that will be imposed for ancillary services prior to commencement of the WESM trading for reserves as well as for ancillary services that will not be traded in the WESM.

1.5. The WESM Reserve Pricing and Cost Recovery Mechanism (the "Reserve PCRM") set forth in this document is intended to supplement the WESM PDM for purposes of providing the details of formula and procedures by which reserve trading amounts and reserve cost recovery charges for the categories of reserve that will be traded in the WESM are calculated. Once approved by the ERC, this Reserve PCRM will apply to all reserve categories traded in the WESM and will supersede, to this extent, the Ancillary Services Cost Recovery Mechanism of the National Transmission Corporation.

[1] WESM Rules Chapter 11

2. ANCILLARY SERVICES ARRANGEMENTS

2.1. Ancillary services, which include reserves, are services that are necessary to support the transmission of capacity and energy from generating resources to loads while maintaining reliable operation of the transmission system in accordance with good utility practice, the Philippine Grid Code and the Philippine Distribution Code. It is therefore an essential component for ensuring the security and reliability of the supply of electricity throughout the power system.

2.2. Management of ancillary services is the mandate of the System Operator as a necessary part of its function to be responsible for and to operate the power system. The System Operator is mandated to arrange for the provision of ancillary services for each region through either competitive tendering process, administered by the Market Operator, whereby a number of ancillary services provider can provide a particular category of ancillary services; or by negotiating contracts directly with ancillary services providers where only one provider can provide the required ancillary services; or by competitive spot market trading. [2]

2.3. Under the **Ancillary Services Procurement Plan** (the "ASPP") of the National Transmission Corporation (the "Transco") approved by the Energy Regulatory Commission (the "ERC"), ancillary services will be procured by the System Operator either through long term contracts or through the WESM. Procurement through long term contracts applies for all ancillary services prior to the commencement of the spot market for reserve, and upon commencement of the trading of reserves in the WESM, for ancillary services that are not classified as reserves[3].

The **Ancillary Services Cost Recovery Mechanism** (the "AS-CRM") likewise formulated by Transco provides for the methodology for determining the allocation of the costs of ancillary services. This is subject of a separate filing with the ERC. As filed with the ERC, the AS-CRM provides for the cost recovery mechanism for all types of ancillary services to be procured by the Transco pursuant to the ASPP. It provides further that for reserve categories that will be traded in the WESM, the mechanism described therein will apply only prior to commencement of the trading of reserves in the WESM.

2.4. Trading of Reserves in the WESM

When reasonably feasible, the Market Operator in consultation with the System Operator is authorized by the WESM Rules to establish and administer a market for the purchase of certain reserve categories.[4] The reserve categories that may be traded in the WESM shall include regulating reserve, contingency reserve and other reserve categories as may be proposed by the Market Operator in consultation with the System Operator and WESM members and approved by the PEM Board.[5]

In conventional power industries, energy and reserves are procured separately in the power system. They have different procurement costs with varying associated methods of cost-recovery mechanisms.

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[2] WESM Rules clause 3.3.3.2

[3] As per 2006 OATS ancillary services not classified as reserves are the black-start and the reactive power support.

[4] WESM Rules clause 10.4.7.2.1 and clause 3.3.4.1

[5] WESM Rules clause 3.3.4.2

Having two separate and distinct markets for both energy and reserves maintain the simplicity of scheduling, procurement and settlement since this implies that energy and reserve allocations are scheduled independent of each other. However, this would mean that most of the time, schedules are not at the optimal level. Capacity allocations between energy and reserve may be lopsided at times, with excess capacity in one market that cannot be used in another. Possible scenarios would be under-generation conditions in the energy market even as there is excess capacity in reserve allocations.

To calculate the optimal balance between energy and reserve, the scheduling of both energy and reserve should consider their interaction with each other and their effect on overall costs in the market. In the Wholesale Electricity Spot Market (WESM), this is embodied in the Market Dispatch Optimization Model (the "MDOM") through reserve co-optimization.

With reserve co-optimization, energy and reserve margins are balanced making sure that energy and reserve margins are kept at the optimum level while overall costs are kept at a minimum. Pricing also becomes more transparent since reserves are now traded in the market, with reserve bids and offers now being subjected to market forces.

3. THE WESM PRICE DETERMINATION METHODOLOGY

3.1. The price determination methodology (the "PDM") for the WESM approved by the ERC is contained in the document entitled *Price Determination Methodology for the Philippine Wholesale Electricity Spot Market Revision 23 January 2006* (the "PDM document"). Among other things, this document sets forth the pricing principles as well as the optimization model that is used for purposes of determining dispatch schedules and prices, and preparing market projections. The optimization model is called the Market Dispatch Optimization Model (the "MDOM"). The MDOM formulation forms part of the WESM PDM approved by the ERC.

3.2. The MDOM is the model that performs market clearing functions for both energy and reserves in the WESM. As described in the PDM document, the MDOM receives information on system conditions and requirements from the System Operator as well as the market offers and bids from trading participants. It then processes this information to come up with the optimum scheduling for both 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 participants. It utilizes linear programming techniques to create a security constrained economic dispatch and calculate energy prices for all market trading nodes and reserve prices for all reserve regions.[6] This process of simultaneous determination of energy schedules and reserve allocation and their associated prices is known as *co-optimization* of energy and reserves. Co-optimization of energy and reserves in the WESM is provided for under Section 3.6 of the WESM Rules.

[6] See Section 4, Price Determination Methodology for the Philippine Wholesale Electricity Spot Market Revision 23 January 2006, page 3.

4. RESERVE PRICING AND COST RECOVERY MECHANISM

4.1. Coverage

The Reserve PCRM covers the determination of (a) reserve trading amounts of reserve providers; (b) determination of reserve cost recovery charges; and (c) administered reserve prices and reserve cost recovery charges.

While already covered in the approved PDM, this document also contains a discussion on the manner by which reserve dispatch schedules and zonal reserve prices are calculated in the MDOM. The discussion is presented for clarity of presentation.

4.2. Objectives

The Reserve PCRM aims to –

a) establish the principles and procedures by which reserves traded in the WESM will be priced as well as the formula and procedures for determining the reserve trading amounts of reserve providers and the allocation of the reserve costs among market participants (the "reserve cost recovery charges"); and

b) establish the methodology to be used for determining the administered prices and cost recovery charges that will be used for settlement of reserve transactions during market suspension or intervention

consistent with the Transco Ancillary Services Procurement Plan ("ASPP") and the Ancillary Services Cost Recovery Mechanism ("AS-CRM").

4.3. Reference/Related Documents

The Reserve PCRM is formulated in accordance with the WESM PDM, the WESM Rules and the EPIRA. This document was also formulated consistent with the latest available copy of the Ancillary Services Cost Recovery Mechanism (the "AS-CRM") formulated by the Transco and filed with the ERC.

4.4. The Electricity Market Model for Reserves in the WESM

The electricity market model of the WESM has been presented in the document WESM Price Determination Methodology ("*PDM*"). For the reserve market, the relevant features of the WESM model are -

4.4.1. The WESM adopts a zonal pricing regime for reserves traded in the spot market for all reserve regions. Zonal reserve pricing is a pricing scheme wherein a single price applies to a reserve region. [7]

4.4.2. Unlike the pricing scheme for energy, an ex-ante pricing scheme is adopted for reserves. This is because reserves are procured in advance to enable the

[7] WESM Rules clause 3.3.5

System Operator to quickly respond or dispatch the energy reserves to maintain power system security and reliability in real-time.[8]

4.5. Reserve Categories to be Traded in the WESM

4.5.1. The WESM Rules provide that the reserve categories that will be traded in the WESM shall include regulating reserve, contingency reserve and such other reserve categories that the Market Operator may propose in consultation with the System Operator and WESM members, and approved by the Philippine Electricity Market Board (the "PEM Board").[9]

4.5.2. At the commencement of the spot market for reserves, the following reserve categories will be traded, consistent with *WESM Rules* clause 3.6.1.1 and 3.3.4.2 (a), (b) and (c) –

Regulating Reserve (REG) – provides the ability to respond to small fluctuations in system frequency including but not limited to those caused by load or generation changes.[10] This is also termed as "Load Following and Frequency Regulation" ("LFFR"). Regulating reserves can be offered by generators certified by the System Operator as a regulating reserve provider and is subject to the regulating headroom constraint in addition to the other reserve constraints.

Contingency Reserve (CON) –the ability to respond to a significant decrease in system frequency including but not limited to a decrease in system frequency in an interconnected AC network as a result of a credible contingency affecting one (or more) generation companies within that network, or transmission flows into that network.[11] This is also termed as "Spinning Reserve". Contingency reserves can be offered by generators certified by System Operator as contingency reserve provider.

Dispatchable Reserve (DIS) – provides the ability to respond to a re-dispatch performed by the System Operator during a trading interval, on either a regular or an ad hoc basis.[12] This is also termed as "Back-up Reserve". Dispatchable reserves can be offered by generators pre-qualified by System Operator.

Interruptible Load (ILD) in lieu of reserve - the ability of a customer to disconnect loads from the grid within a very short notice in response to a frequency deviation or a request of the System Operator.[13] ILD can be bidded by Customers with loads certified by the System operator as dispatchable.

[8] WESM Rules clause 3.10.1 (e), 3.10.10
[9] WESM Rules clause 3.3.4.2
[10] WESM Rules, Chapter 11, Glossary
[11] WESM Rules, Chapter 11, Glossary
[12] WESM Rules, Chapter 11, Glossary
[13] WESM Rules, Chapter 11, Glossary

4.5.3. Table 1 shows the equivalent reserve type names adopted in the OATS Rules with the reserve categories to be traded in the WESM.

Table 1 - Equivalence Matrix for Reserves

OATS Rules (2004)	OATS Rules (2006)	WESM Reserve Categories
Load Following and Frequency Regulation	Regulating Reserve	Regulating Reserve
Contingency Reserve – Spinning Reserve	Contingency Reserve	Contingency Reserve
Contingency Reserve – Back-Up Power Supply	Dispatchable Reserve	Dispatchable Reserve
Customer Load Dropping	(not included in the filing)	Interruptible Loads in Lieu of Reserve

4.6. Reserve Regions and Cost Recovery Zones

4.6.1. A reserve region is defined in the WESM Rules as a zone in the power system from which a particular reserve category can be supplied to meet a particular location-specific requirement. On the other hand, a reserve cost recovery zone refers to a zone within which reserve cost recovery charges may be recovered to meet each location-specific requirement. [14]

4.6.2. Given these definitions, the determination of what makes up a reserve region and cost recovery zone should take into the operational aspects of the power system. Currently, there are three power system grids operated by the System Operator with localized control for reserve requirement. These are the Luzon grid, Visayas grid, and Mindanao grid.

4.6.3. Thus, for the WESM, the reserve regions will consist of the Luzon and the Visayas grids. The market trading nodes within each grid will be grouped together to likewise make up two corresponding reserve cost recovery zones, i.e., Luzon and Visayas. While the Mindanao grid will likewise make up a separate reserve region, the allocation of reserves for this grid will not be included in the trading in the WESM.

5. ALLOCATION OF RESERVES

5.1. Determination of Reserve Dispatch Schedule

Pursuant to the central scheduling process set in the *WESM Rules*, all generators will submit offers to the market for all the energy and reserve they intend to produce irrespective of their

[14] WESM Rules, Chapter 11, Definitions.

contracts with their customers. Customers with *dispatchable loads* have the option to post their demand bids in the market or qualify as an Interruptible Load (ILD) reserve provider and submit ILD offers. The *Market Operator* considers the submitted bids and offers and will then schedule all the available generation to meet the forecasted load and reserve requirements, taking into account the capabilities of the transmission network to transport the energy from generators to costumers and the limitations of the individual generating resources. This dispatch model where all energy and reserve is traded through the WESM is known as the *gross pool*.

The resulting *reserve schedule* is the amount of capacity that is allocated to a reserve provider that may be called upon by the System Operator at any time to maintain the security and reliability of the power system. Meanwhile, the resulting energy *dispatch schedule* is the schedule followed by generating facilities and takes account of all *constraint* parameters present in the system for the relevant time interval in order to maintain power balance in the *grid*.

Figure 1 below provides an overview of the market dispatch scheduling and pricing.

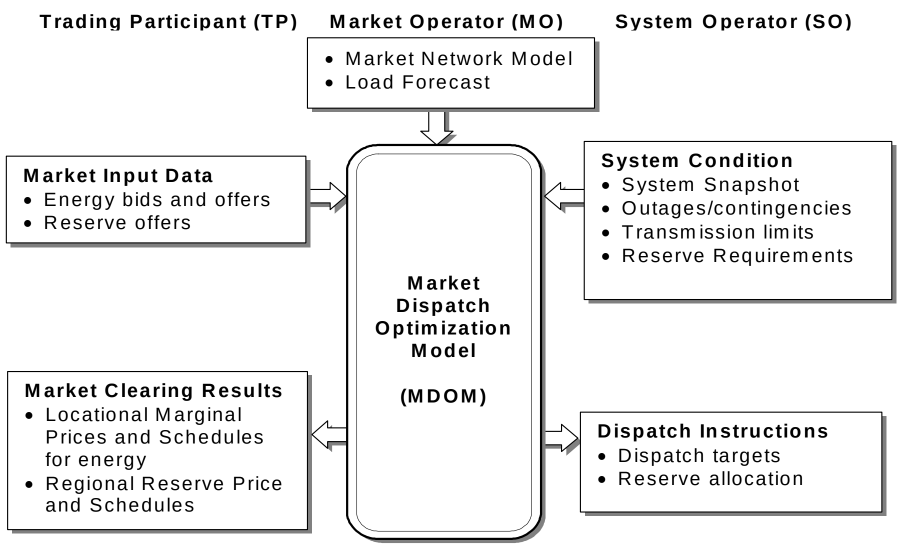


Figure 1. Market Pricing and Scheduling Overview

5.1.1. Submission of offers and bids

The *trading participants* will submit their respective *market offers* or bids to the market through the market interface that is provided by the *Market Operator*. The generators must submit a price and quantity offer to the *Market Operator*, while the customers may submit price and quantity bids.

The same timetable is used for the submission of bids and offers for both energy and reserves. The trading participant submit daily and standing bids or offers, and these may be revised within the set timetable.

Standing Bids/Offers remain valid until it is revised by a new *standing offer/bid*. Offers/Bids for specific trading days and *trading intervals* may be overridden by an offer/bid revision. Once the period covered by the offer/bid revision has expired, however, the standing offer/bid is again in effect.

A revision of a *standing offer/bid* may be done at anytime in accordance with the market *timetable*[15]**.** The changes will, however, take effect from the end of the *trading interval* covered by the last published or initiated week-ahead projection (i.e. from current day, *D,* plus seven days) and before the week-ahead projection is initiated, or at *D* plus eight days after the revision is submitted. Any revisions within the time in which the revision of *standing offer/bid* has not yet taken effect must be done as revision offer/bid and not as revised standing offers/bids.

Revision Bids/Offers - For the week-ahead market projection covering D+1 to D+7, all offer/bid revisions for scheduled generation or load facilities are to be submitted and confirmed by the *trading participants* before 0900h of the current day, *D*.

For the day-ahead market projections, all offer/bid revisions for scheduled generation or load facilities are to be submitted and confirmed by the *trading participants* before 0000h, 0400h, 0800h, 1200h, 1600h, 2000h of the current day, *D*.

For the current trading day, all offer revisions for scheduled generation or load facilities are to be submitted and confirmed before gate closure, which is two hours before the start of the *trading interval* for which the offers/bids being revised are made.

5.1.2. **Scheduling/Co-optimization of Energy and Reserves**

Through the MDOM, the reserve offers submitted by the reserve providers are ranked from the lowest to the highest price offer. Reserve allocation for each generating or load facility providing reserve are stacked based on their price offer until the *reserve requirement* for a particular type of reserve is met. Similarly, the energy offers submitted by the generators are ranked from the lowest to the highest price offer, while the bids submitted by the customers are ranked from the highest to the lowest price offer. Generating facilities that are scheduled to run are stacked based on their price offers until the total generation matches the total load requirement for a particular trading interval.

Based on its objective function, the MDOM simultaneously takes into account all these offers together with the capabilities of the transmission network to transport the energy from generators to customers and the limitations of the individual generating or load resources to maximize gains from the trade or minimize the total cost of the solution to come up with the optimum energy schedules and reserve allocations and the associated prices. The MDOM then co-optimizes the energy and reserve offers to produce a dispatch

[15] For the details of the market timetable, see the *Dispatch Protocol* in Annex E.

solution that represents the interaction of both energy and reserve in the market.

5.2. Determination of Zonal Reserve Price

The zonal reserve price for a region or zone within the system represents the economic value of providing reserves given the reserve supply and requirement interaction at a particular reserve region. The zonal reserve price signals the economic value of ensuring the reliability and security of power supply at a particular reserve region given the specific system condition in a particular trading interval. A single reserve price for each reserve type in a specified reserve region is derived as the power system is equivalently seen as a single machine which must be managed in real-time and whose individual parts must operate in a synchronized manner to ensure that the supply and demand of electricity is balanced at all times and within the specified limits as specified in the Philippine Grid Code.

The MDOM derives this single price for each reserve type and the reserve schedules simultaneous with the dispatch schedule and the locational marginal price for energy. In the same manner as the system clearing price for energy is derived, the MDOM considers the marginal cost of satisfying the reserve requirement for each type of reserve. The effect of physical transmission losses and network constraints do not have a direct effect on *zonal reserve price*[16]. However, when reserve is co-optimized with energy (and in the process minimizes the total system cost of providing electricity to meet the demand and the provision of reserves to securely and reliably deliver the electricity), generators that offer both energy and reserve may incur an *"opportunity cost"*. That is if by providing reserve (or energy), the generator is held back from profitably selling energy (or reserve) into the spot market, it incurs an additional *opportunity cost* which is equal to profit foregone. This opportunity cost is a function of the marginal reserve offer price(s), marginal energy offer price(s) and the nodal price(s) at the location of the marginal resource(s) and is a by-product of the optimization solution.

As such, in cases where opportunity cost is reflected in either the energy or reserve price, the co-optimized schedule and the total system cost is still the optimum or least cost solution that minimizes the overall market costs for all participants. A simple illustration is included in Appendix 1 to illustrate this principle.

5.3. Constraint Violation Coefficients

The Market Dispatch Optimization Model solves for the dispatch schedule and prices using an optimization solution. However, if the optimization solution becomes infeasible and the infeasibility is due to insufficient reserve offers in the market, deficit reserve constraints are allowed to be violated and the associated penalty costs are reflected in the resulting market prices. These penalty costs are called the *Constraint Violation Coefficients ("CVCs")*.[17]

For reserves, there are four types of CVCs incorporated in the MDOM. These are:

- Deficit Interruptible Load Reserve
- Deficit Dispatchable Reserve
- Deficit Regulating Reserve

[16] This is due to the fact that the reserves are a requirement of the whole reserve region.

[17] See *Price Determination Methodology for the Philippine Wholesale Electricity Spot Market Revision 23 January 2006;* and *WESM Manual Constraint Violation Coefficients.*

- Deficit Contingency Reserve

However, unlike the other types of CVCs that are related to energy, if the initial optimization results encounter infeasibility due to deficit reserve offers, a second optimization process with a reduced reserve requirement is initiated by the MDOM.[18] The second optimization solution is automatically run by the MDOM with more relaxed reserve requirement constraints. Instead of imposing reserve constraints equal to the reserve requirement, the reserve requirement is relaxed and set equal to the maximum possible amount of reserve offer available for dispatch. This value, subject to reserve tolerance parameter, becomes the new reserve requirement constraint.

That is, if the reserve requirement (e.g. regulating reserve) is 200 MW and the total available reserve offer (for regulation) is only 100MW, a deficit regulating reserve CVC would be imposed in the resulting market prices. To avoid this situation, a 2nd optimization solution is automatically run by the software wherein the reserve requirement is relaxed to 100MW. In this solution, the CVC will not affect the resulting prices and therefore a feasible solution is achieved.

The rationale for this relaxed constraint is to minimize the possibility of infeasible schedules (and prices reflecting CVCs) in the energy market as a result of infeasibilities encountered by the MDOM due primarily to deficit reserves in the market particularly if the deficit reserve offer is only marginal. The second optimization solution with relaxed constraints will make sure that the market results are not distorted by this unnecessary price signal. Should there be significant deficits in reserve, however, the System Operator is mandated to maintain the security and reliability of the power system consistent with the System Security and Reliability Guidelines of the WESM and the Philippine Grid Code.

6. SETTLEMENT OF RESERVE TRANSACTIONS

The settlement of reserve transactions involves the determination of (a) the reserve trading amount to be paid to the reserve providers and (b) the reserve cost recovery charges to be allocated to and collected from those benefited by the reserve allocations.

6.1. Determination of the Reserve Trading Amount

6.1.1. Principles

For *reserves* transactions, only the *ex-ante reserve trading amount* is calculated. This is different from the settlement process for *energy* which involves the determination of both the *ex-ante energy trading amount* and *ex-post energy trading amount*, adjusted for *bilateral contract* quantities in accordance with *WESM Rules* clause 3.13.7.

The *reserve trading amount* for each *trading participant* that provided reserves for each *reserve category* and *trading interval* is the product of the *ex-ante zonal reserve price* multiplied by the *ex-ante reserve settlement quantity for each reserve category.*[19]

The *ex-ante zonal reserve prices* and *reserve settlement quantities* are outputs of the MDOM representing the expected prices at the *reserve zones* and quantities at the *market*

[18] WESM Rules change clause 3.9.9
[19] See WESM Rules clause 3.13.10

trading nodes, and are scheduled by the *Market Operator* prior to actual *dispatch* by the *System Operator*. Their values depends on generation offers, reserve offers, and demand bids submitted by the *trading participants* at the times set in the market timetable[20], and the *reserve requirement* levels prepared by the *System Operator*.[21]

6.1.2. Formulations

The working formulations for determining reserve trading amounts of the reserve providers are as follows:

Regulating Reserve: $REGRTA_{i,h}^{a} = (REGEARSP_{h}^{a} \times REGEAQSI_{i,h}^{a})$

Where:

$REGRTA_{i,h}^{a}$ represents the *regulating reserve trading amount* for Generator "*i*" at *trading interval* "*h*" and *reserve region* "*a*";

$REGEARSP_{h}^{a}$ is the *ex-ante regulating reserve settlement price* for the *trading interval* "*h*" and *reserve region* "*a*", which is the co-optimized price of the marginal regulating reserve generator at that region;

$REGEAQSI_{i,h}^{a}$ is the *ex-ante* quantity of regulating reserve that is scheduled for generator "*i*" for *trading interval "h"* and *reserve region* "*a*";

Contingency Reserve: $CONRTA_{i,h}^{a} = (CONEARSP_{h}^{a} \times CONEAQSI_{i,h}^{a})$

Where:

$CONRTA_{i,h}^{a}$ represents the *contingency reserve trading amount* for Generator "*i*" at *trading interval* "*h*" and *reserve region* "*a*";

$CONEARSP_{h}^{a}$ is the *ex-ante contingency reserve settlement price* for the *trading interval* "*h*" and *reserve region* "*a*", which is the co-optimized price of the marginal contingency reserve generator at that region;

$CONEAQSI_{i,h}^{a}$ is the *ex-ante* quantity of contingency reserve that is scheduled for generator "*i*" for *trading interval "h"* and *reserve region* "*a*";

Dispatchable Reserve: $DISRTA_{i,h}^{a} = (DISEARSP_{h}^{a} \times DISEAQSI_{i,h}^{a})$

Where:

$DISRTA_{i,h}^{a}$ represents the *dispatchable reserve trading amount* for Generator "*i*" at *trading interval* "*h*" and *reserve region* "*a*";

[20] See Annex E, *Dispatch Protocol*, for the timeline on the submission of offers/bids into the WESM.
[21] See Annex E, *Dispatch Protocol*.

$DISEARSP_h^a$ is the *ex-ante dispatchable reserve settlement price* for the *trading interval* "*h*" and *reserve region* "*a*", which is the co-optimized price of the marginal dispatchable reserve generator at that region;

$DISEAQSI_{i,h}^a$ is the *ex-ante* quantity of dispatchable reserve that is scheduled for generator "*i*" for *trading interval "h"* and *reserve region* "*a*";

Interruptible Load Reserve: $ILDRTA_{j,h}^a = (ILDEARSP_h^a \times ILDEAQSI_{j,h}^a)$

Where:

$ILDRTA_{j,h}^a$ represents the *interruptible load reserve trading amount* for Load "*j*" at *trading interval* "*h*" and *reserve region* "*a*";

$ILDEARSP_h^a$ is the *ex-ante interruptible load reserve settlement price* for the *trading interval* "*h*" and *reserve region* "*a*", which is the co-optimized price of the marginal interruptible load reserve at that region;

$ILDEAQSI_{j,h}^a$ is the *ex-ante* quantity of *interruptible load reserve* that is scheduled for curtailment by the load "*j*" for *trading interval "h"* and *reserve region* "*a*";

6.2. Determination of the Reserve Cost Recovery Charges

6.2.1. Allocation of Reserve Cost Recovery Charges/Allocation Factors

Reserve Cost Recovery Charge is defined in the WESM Rules as the charges to recover the cost incurred in purchasing reserve, to be determined by a formula approved by the ERC.[22]

The costs of providing each locationally specific reserve requirement shall be allocated by the Market Operator to the trading participants in a relevant reserve cost recovery zone pursuant to the principles set forth in the WESM Rules particularly in clause 3.3.5.4.[23]

The reserve cost recovery charge shall be imposed on the trading participants within each reserve cost recovery zone, for each type of reserve traded in the WESM, based on their respective allocation factors. The costs are allocated among[24] –

a) customers with load facilities connected in the relevant reserve cost recovery zone; and

b) scheduled generation companies with generating systems connected in the relevant reserve cost recovery zone.

[22] WESM Rules Chapter 11, Definitions
[23] WESM Rules clause 3.3.5.3
[24] WESM Rules clause 3.3.5.4 (a), (b)

The allocation factors are as follows –

a) Regulation reserve - 50% Generator, 50% Customer
b) Contingency reserve – 100% Generator
c) Dispatchable reserve – 100% Generator
d) Interruptible Load – 100% Generator

The allocation factors for the Regulation, Contingency and Dispatchable Reserves are consistent with the allocation prescribed in Tranco's Ancillary Services Cost Recovery Mechanism (the "AS-CRM"). Interruptible Load, on the other hand, is used in lieu of contingency reserves, in which case its allocation should also be the same as the allocation for Contingency and Dispatchable reserves, i.e., 100% allocation to generators.

The Market Management System is flexible in terms of changing these allocation factors in the cost allocation formula. Any changes, therefore, in cost allocation factors can be easily implemented by the Market Operator.

6.2.2. **Formulations**

The reserve cost recovery charge formula set forth in this document shall cover the reserves that will be traded in the WESM. Once approved by the ERC, it will supersede the cost recovery formula set forth in the Ancillary Services Procurement Plan (the "ASPP") and the Ancillary Services Cost Recovery Mechanism (the "AS-CRM") of the National Transmission Corporation, in respect to the reserves that will be traded in the WESM.

It will be noted, however, that the formulation set forth in this document adopted the formulation contained in the original Ancillary Services Procurement Plan (ASPP) of Transco. Some modifications are introduced to provide more details to the formulation.

Regulating Reserve Cost Allocation

$$\mathrm{Charge}_{\mathrm{REG}_h}^{\mathrm{Gen}_{a,i}} = \mathrm{Cost}_{\mathrm{REG}_a}^{h} \times \left[\frac{\mathrm{Energy}_{a,i}^{\text{Gen, ex-ante}}}{\sum_i \mathrm{Energy}_{a,i}^{\text{Gen, ex-ante}}}\right]^h \times G_{REG}$$

$$\mathrm{Charge}_{\mathrm{REG}_h}^{\mathrm{Load}_{a,j}} = \mathrm{Cost}_{\mathrm{REG}_a}^{h} \times \left[\frac{\mathrm{Energy}_{a,j}^{\text{Load, ex-ante}}}{\sum_j \mathrm{Energy}_{a,j}^{\text{Load, ex-ante}}}\right]^h \times \left(1 - G_{REG}\right)$$

$$\mathrm{Cost}_{\mathrm{REG}_a}^{h} = \sum_i \mathrm{REGRTA}_{i,h}^{a}$$

$$0\% \le \mathrm{G}_{\mathrm{REG}} \le 100\%$$

Where:

$\text{Charge}_{\text{REG}_h}^{\text{Gen}_{a,i}}$	Total hourly cost allocation of Regulating Reserve for the Generator "i" in reserve region "a"
$\text{Energy}_{a,i}^{\text{Gen, ex-ante}}$	Hourly energy schedule of Generator "i" for the Trading Interval "h" in reserve region "a"
$\text{Charge}_{\text{REG}_h}^{\text{Load}_{a,j}}$	Total hourly cost allocation of Regulating Reserve for the Load "j" in reserve region "a"
$\text{Energy}_{a,j}^{\text{Load, ex-ante}}$	Hourly energy schedule of Load "j" for the Trading Interval "h" in reserve region "a"
G_{REG}	Percentage cost allocation of Regulating Reserve to all Generators
$\text{Cost}_{\text{REG}_a}^{h}$	Total cost of Regulating Reserve for the Trading Interval "h" in reserve zone "a".
$\text{REGRTA}_{i,h}^{a}$	The *regulating reserve trading amount* for Generator "*i*" at *trading interval* "*h*" and *reserve region* "*a*"

Contingency Reserve Cost Allocation

$$\text{Charge}_{\text{CON}_h}^{\text{Gen}_{a,i}} = \text{Cost}_{\text{CON}_a}^{h} \times \left[\frac{\text{Energy}_{a,i}^{\text{Gen, ex-ante}}}{\sum_i \text{Energy}_{a,i}^{\text{Gen, ex-ante}}} \right]^h \times G_{CON}$$

$$\text{Charge}_{\text{CON}_h}^{\text{Load}_{a,j}} = \text{Cost}_{\text{CON}_a}^{h} \times \left[\frac{\text{Energy}_{a,j}^{\text{Load, ex-ante}}}{\sum_j \text{Energy}_{a,j}^{\text{Load, ex-ante}}} \right]^h \times \left(1 - G_{CON}\right)$$

$$\text{Cost}_{\text{CON}_a}^{h} = \sum_i \text{CONRTA}_{i,h}^{a}$$

$$0\% \leq \text{G}_{\text{CON}} \leq 100\%$$

Where:

$\text{Charge}_{\text{CON}_h}^{\text{Gen}_{a,i}}$	Total hourly cost allocation of Contingency Reserve for the Generator "i" in reserve region "a"
$\text{Energy}_{a,i}^{\text{Gen, ex-ante}}$	Hourly energy schedule of Generator "i" for the Trading Interval "h" in reserve region "a"
$\text{Charge}_{\text{DIS}_h}^{\text{Load}_{a,j}}$	Total hourly cost allocation of Contingency Reserve for the Load "j" in reserve region "a"

$\text{Energy}_{a,j}^{\text{Load, ex-ante}}$	Hourly energy schedule of Load "j" for the Trading Interval "h" in reserve region "a"
G_{CON}	Percentage cost allocation of Contingency Reserve to all Generators
$\text{Cost}_{\text{CON}_a}^{h}$	Total cost of Contingency Reserve for the Trading Interval "h" in reserve zone "a".
$\text{CONRTA}_{i,h}^{a}$	The *contingency reserve trading amount* for Generator "*i*" at *trading interval* "*h*" and *reserve region* "*a*"

Dispatchable Reserve Cost Allocation

$$\text{Charge}_{\text{DIS}_h}^{\text{Gen}_{a,i}} = \text{Cost}_{\text{DIS}_a}^{h} \times \left[\frac{\text{Energy}_{a,i}^{\text{Gen, ex-ante}}}{\sum_i \text{Energy}_{a,i}^{\text{Gen, ex-ante}}} \right]^{h} \times G_{DIS}$$

$$\text{Charge}_{\text{DIS}_h}^{\text{Load}_{a,j}} = \text{Cost}_{\text{DIS}_a}^{h} \times \left[\frac{\text{Energy}_{a,j}^{\text{Load, ex-ante}}}{\sum_j \text{Energy}_{a,j}^{\text{Load, ex-ante}}} \right]^{h} \times \left(1 - G_{DIS}\right)$$

$$\text{Cost}_{\text{DIS}_a}^{h} = \sum_i \text{DISRTA}_{i,h}^{a}$$

$$0\% \le G_{DIS} \le 100\%$$

Where:

$\text{Charge}_{\text{DIS}_h}^{\text{Gen}_{a,i}}$	Total hourly cost allocation of Dispatchable Reserve for the Generator "i" in reserve region "a"
$\text{Energy}_{a,i}^{\text{Gen, ex-ante}}$	Hourly energy schedule of Generator "i" for the Trading Interval "h" in reserve region "a"
$\text{Charge}_{\text{DIS}_h}^{\text{Load}_{a,j}}$	Total hourly cost allocation of Dispatchable Reserve for the Load "j" in reserve region "a"
$\text{Energy}_{a,j}^{\text{Load, ex-ante}}$	Hourly energy schedule of Load "j" for the Trading Interval "h" in reserve region "a"
G_{DIS}	Percentage cost allocation of Dispatchable Reserve to all Generators
$\text{Cost}_{\text{DIS}_a}^{h}$	Total cost of Dispatchable Reserve for the Trading Interval "h" in reserve zone "a".
$\text{DISRTA}_{i,h}^{a}$	The *dispatchable reserve trading amount* for Generator "*i*" at *trading interval* "*h*" and *reserve region* "*a*"

Interruptible Load Reserve Cost Allocation

$$\mathrm{Charge}_{\mathrm{ILD}_h}^{\mathrm{Gen}_{a,i}} = \mathrm{Cost}_{\mathrm{ILD}_a}^{h} \times \left[\frac{\mathrm{Energy}_{a,i}^{\mathrm{Gen,\ ex\text{-}ante}}}{\sum_i \mathrm{Energy}_{a,i}^{\mathrm{Gen,\ ex\text{-}ante}}} \right]^h \times G_{ILD}$$

$$\mathrm{Charge}_{\mathrm{ILD}_h}^{\mathrm{Load}_{a,j}} = \mathrm{Cost}_{\mathrm{ILD}_a}^{h} \times \left[\frac{\mathrm{Energy}_{a,j}^{\mathrm{Load,\ ex\text{-}ante}}}{\sum_j \mathrm{Energy}_{a,j}^{\mathrm{Load,\ ex\text{-}ante}}} \right]^h \times \left(1 - G_{ILD}\right)$$

$$\mathrm{Cost}_{\mathrm{ILD}_a}^{h} = \sum_j \mathrm{ILDRTA}_{j,h}^{a}$$

$$0\% \le \mathrm{G}_{\mathrm{ILD}} \le 100\%$$

Where:

$\mathrm{Charge}_{\mathrm{ILD}_h}^{\mathrm{Gen}_{a,i}}$	Total hourly cost allocation of Interruptible Load Reserve for the Load "i" in reserve region "a"
$\mathrm{Energy}_{a,i}^{\mathrm{Gen,\ ex\text{-}ante}}$	Hourly energy schedule of Load "i" for the Trading Interval "h" in reserve region "a"
$\mathrm{Charge}_{\mathrm{ILD}_h}^{\mathrm{Load}_{a,i}}$	Total hourly cost allocation of Interruptible Load Reserve for the Load "j" in reserve region "a"
$\mathrm{Energy}_{a,j}^{\mathrm{Load,\ ex\text{-}ante}}$	Hourly energy schedule of Load "j" for the Trading Interval "h" in reserve region "a"
$\mathrm{G}_{\mathrm{ILD}}$	Percentage cost allocation of Interruptible Load Reserve to all Generators
$\mathrm{Cost}_{\mathrm{ILD}_a}^{h}$	Total cost of Interruptible Load Reserve for the Trading Interval "h" in reserve zone "a".
$\mathrm{ILDRTA}_{j,h}^{a}$	The *interruptible load reserve trading amount* for Load "*j*" at *trading interval* "*h*" and *reserve region* "*a*"

7. Administered Reserves Schedule, Price and Cost Recovery Charge Determination Methodology

7.1. During market suspension or intervention, the System Operator performs both the scheduling and dispatching functions, for both energy and reserves. For settlement of transactions during the affected trading intervals, the *WESM Rules* authorizes *the Market Operator* to use an *administered price*.[25]

7.1.1. For the energy market, the ERC has prescribed that the administered price for a given trading interval shall be equivalent to the load weighted average ex-post energy price of the corresponding trading interval of the four (4) preceding similar days, that have not been administered. In case any of the prices covered by the four preceding same days have been administered, said prices shall be excluded and replaced with the prices that have not been administered from the most recent earlier same or similar day. In addition, the trading participant which has complied with the instructions during market suspension or intervention may be entitled to additional compensation upon determination and sufficient proof that the administered price is not sufficient to cover the fuel costs as well as variable operating and maintenance costs incurred in complying with the dispatch instructions.[26]

7.1.2. For the reserve market, a similar methodology for determining the administered price will be implemented.

7.2. Application

7.2.1. The administered price and cost recovery mechanism will be used for settlement of transactions when the market is suspended by the ERC or at trading intervals during market intervention where the Market Operator is unable to generate feasible reserve price and schedules.

7.2.2. The administered price and cost recovery mechanism applies to reserves procured through the WESM.

7.3. Methodology

7.3.1. **Administered Reserve Price -** For every reserve pricing zone, the administered price to be paid to the reserve providers shall be computed as the load weighted average reserve price of the four most recent same-day and same trading intervals that have not been administered.

Thus, for a reserve pricing zone, the following formulas determine the administered reserve price:

[25] See WESM Rules clause 6.2.3

[26] See Decision in ERC Case No. 2005-056 RC *In the Matter of the Application for Approval of the Administered Price Determination Methodology for the Philippine Wholesale Electricity Spot Market*, 22 June 2006; and *WESM Manual Administered Price Determination Methodology, Issue 2.0, Revision 1.*

For Regulating Reserve:

$$\mathrm{REGARP}_h^a = \frac{\sum_{Day=1}^{4} (REGEARSP_h^a * REGEAQSI_{i,h}^a)_{mostrecent}}{\sum_{Day=1}^{4} (REGEAQSI_{i,h}^a)_{mostrecent}}$$

Where:

$REGARP_h^a$ is the Administered Reserve Price for *regulating reserve* for the *trading interval* "*h*" and *reserve region* "*a*".

$REGEARSP_h^a$ is the *ex-ante regulating reserve settlement price* for the *recent trading interval* "*h*" and *reserve region* "*a*", which is the co-optimized price of the marginal regulating reserve generator at that region;

$REGEAQSI_{i,h}^a$ is the *ex-ante* quantity of *regulating reserve* that is scheduled for injection by the generator "*i*" for the *recent trading interval* "*h*" and *reserve region* "*a*";

For Contingency Reserve:

$$\mathrm{CONARP}_h^a = \frac{\sum_{Day=1}^{4} (CONEARSP_h^a * CONEAQSI_{i,h}^a)_{mostrecent}}{\sum_{Day=1}^{4} (CONEAQSI_{i,h}^a)_{mostrecent}}$$

Where:

$CONARP_h^a$ is the Administered Reserve Price for *contingency reserve* for the *trading interval* "*h*" and *reserve region* "*a*".

$CONEARSP_h^a$ is the *ex-ante contingency reserve settlement price* for the *recent trading interval* "*h*" and *reserve region* "*a*", which is the co-optimized price of the marginal contingency reserve generator at that region;

$CONEAQSI_{i,h}^a$ is the *ex-ante* quantity of *contingency reserve* that is scheduled for injection by the generator "*i*" for *the recent trading interval* "*h*" and *reserve region* "*a*";

For Dispatchable Reserve:

$$\mathrm{DISARP}_h^a = \frac{\sum_{Day=1}^{4} (DISEARSP_h^a * DISEAQSI_{i,h}^a)_{mostrecent}}{\sum_{Day=1}^{4} (DISEAQSI_{i,h}^a)_{mostrecent}}$$

Where:

$DISARP_h^a$ is the Administered Reserve Price for *dispatchable reserve* for the *trading interval* "*h*" and *reserve region* "*a*".

$DISEARSP_h^a$ is the *ex-ante dispatchable reserve settlement price* for the *recent trading interval* "*h*" and *reserve region* "*a*", which is the co-optimized price of the marginal dispatchable reserve generator at that region;

$DISEAQSI_{i,h}^a$ is the *ex-ante* quantity of *dispatchable reserve* that is scheduled for injection by the generator "*i*" for *the recent trading interval* "*h*" and *reserve region* "*a*";

<u>For Interruptible Load Reserve:</u>

$$\mathrm{ILDARP}_h^a = \frac{\sum_{Day=1}^{4}(ILDEARSP_h^a * ILDEAQSI_{j,h}^a)_{mostrecent}}{\sum_{Day=1}^{4}(ILDEAQSI_{j,h}^a)_{mostrecent}}$$

Where:

$ILDARP_h^a$ is the Administered Reserve Price for *interruptible load reserve* for the *trading interval* "*h*" and *reserve region* "*a*".

$ILDEARSP_h^a$ is the *ex-ante interruptible load reserve settlement price* for the *recent trading interval* "*h*" and *reserve region* "*a*", which is the co-optimized price of the marginal *interruptible load reserve* generator at that region;

$ILDEAQSI_{j,h}^a$ is the *ex-ante* quantity of *interruptible load reserve* that is scheduled for curtailment by the load "*j*" for *the recent trading interval* "*h*" and *reserve region* "*a*";

These administered reserve price formulas are further subject to the following conditions:

a) Days shall be Mondays to Sundays and holidays. Holidays refer to all non-business days.

b) In case any of the prices covered by the four preceding days have been administered, said prices shall be excluded and replaced by the reserve price of the next most recent earlier same day and same interval.

c) In case any of the prices of the four preceding days reflected constraint violation coefficient prices, the prices derived from the market re-run will be used.

7.3.2. **Administered Reserve Trading Amount** – Using the administered reserve price computed from the preceding section, the total reserve trading amounts of the reserve providers are calculated for settlement purposes. The working formulations for determining reserve trading amounts of the reserve providers using the *administered reserve price* are as follows:

For Regulating Reserve: $REGRTA_{i,h}^{a} = (REGARP_{h}^{a} \times REGSQ_{i,h}^{a})$

Where:

$REGRTA_{i,h}^{a}$ represents the *regulating reserve trading amount* for Generator "*i*" at *trading interval* "*h*" and *reserve region* "*a*";

$REGARP_{h}^{a}$ is the Administered Reserve Price for *regulating reserve* for the *trading interval* "*h*" and *reserve region* "*a*".

$REGSQ_{i,h}^{a}$ is the scheduled quantity of *regulating reserve* as determined by the System Operator, during market suspension or intervention, for the generator "*i*" for *trading interval "h"* and *reserve region* "*a*";

For Contingency Reserve: $CONRTA_{i,h}^{a} = (CONARP_{h}^{a} \times CONSQ_{i,h}^{a})$

Where:

$CONRTA_{i,h}^{a}$ represents the *contingency reserve trading amount* for Generator "*i*" at *trading interval* "*h*" and *reserve region* "*a*";

$CONARP_{h}^{a}$ is the Administered Reserve Price for *contingency reserve* for the *trading interval* "*h*" and *reserve region* "*a*".

$CONSQ_{i,h}^{a}$ is the scheduled quantity of contingency reserve as determined by the System Operator, during market suspension or intervention, for the generator "*i*" for *trading interval "h"* and *reserve region* "*a*";

For Dispatchable Reserve: $DISRTA_{i,h}^{a} = (DISARP_{h}^{a} \times DISSQ_{i,h}^{a})$

Where:

$DISRTA_{i,h}^{a}$ represents the *dispatchable reserve trading amount* for Generator "*i*" at *trading interval* "*h*" and *reserve region* "*a*";

$DISARP_{h}^{a}$ is the Administered Reserve Price for *dispatchable reserve* for the *trading interval* "*h*" and *reserve region* "*a*".

$DISSQ_{i,h}^{a}$ is the scheduled quantity of dispatchable reserve as determined by the System Operator, during market suspension or intervention, for the generator "*i*" for *trading interval "h"* and *reserve region* "*a*";

For Interruptible Load Reserve: $ILDRTA_{j,h}^{a} = (ILDARP_{h}^{a} \times ILDSQ_{j,h}^{a})$

Where:

$ILDRTA_{j,h}^{a}$ represents the *interruptible load reserve trading amount* for Load "*j*" at *trading interval* "*h*" and *reserve region* "*a*";

$ILDARP_{h}^{a}$ is the Administered Reserve Price for *interruptible load reserve* for the *trading interval* "*h*" and *reserve region* "*a*".

$ILDSQ_{j,h}^{a}$ is the scheduled quantity of *interruptible load reserve* as determined by the System Operator, during market suspension or intervention, for the load "*j*" for *trading interval "h*" and *reserve region* "*a*";

7.3.3. **Administered reserve cost recovery charge** - The total reserve trading amounts of the reserve providers calculated as provided for in the preceding section will be allocated among the Trading Participants similar to the cost recovery mechanism discussed in section 6.2. The only difference however is that the *administered reserve price* is used in computing the reserve cost recovery charge.

Appendix 1 – Reserve Co-optimization Example

In trading reserves in the WESM, *Reserve Co-optimization* is used to calculate the optimal balance between energy and reserve schedules. This is inherent in the Market Dispatch Optimization Model (MDOM). In *Reserve Co-optimization*, the interaction between energy and reserve is considered to make sure that the resulting energy schedules and reserve allocations are dispatched to minimize overall costs in the market.

The following examples highlight the concept of Reserve Co-optimization. Take note that reserve co-optimization is done automatically by the MDOM.

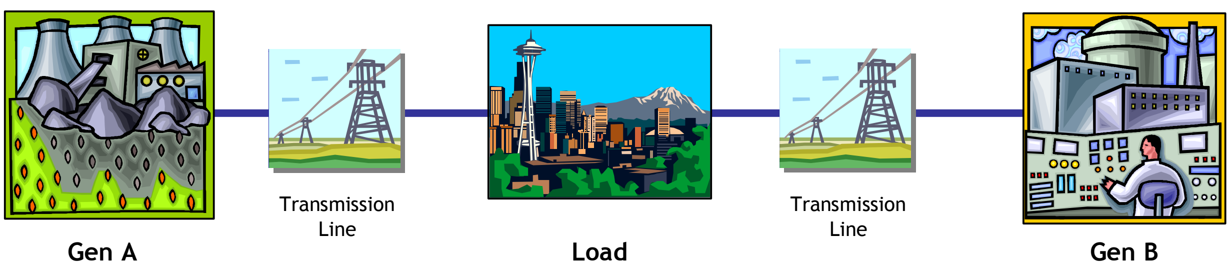
EXAMPLE 1 – Reserve Co-optimization

In this example, energy and reserve are co-optimized to obtain the optimal solution to the economic dispatch problem. Losses and transmission line limits are not considered to simplify analysis.

Location 2
Generator A
Energy: 7,000 MW @ P1,000/MWh
Reserve: 7,000 MW @ P100/MWh

Location1
Load Center
Demand = 6,000 MW
REG Reserve Requirement = 500

Location3
Generator B
Energy: 6,000 MW @ P2,000/MWh
Reserve: 6,000 MW @ 200/MWh



Base Case 1 - Objective Function Cost

Energy	Q	P	Cost
Gen A Energy	6,000	1,000	6,000,000
Gen B Energy	0	2,000	0
Reserve	**Q**	**P**	**Cost**
Gen A Reserve	500	100	50,000
Gen B Reserve	0	200	0
		Total Objective Function Cost	**6050000**

Base Case 1 - Settlement

Settlement	Sched	LMP	EAETA
Gen A Energy	6,000	1000	6,000,000
Gen B Energy	0	1000	0
Settlement	**Sched**	**ZRP**	**RTA**
Gen A Reserve	500	100	50,000
Gen B Reserve	0	100	0
		Total EAETA + RTA	**6,050,000**

Both energy and reserve are scheduled from Gen A because this generator has the cheapest energy and reserve offer. Scheduling Gen B for either energy or reserve will result in a more expensive solution. The aim of reserve co-optimization is to optimize the solution for both energy and reserve, and this is achieved as shown in this simple example.

As for cost recovery, the costs are allocated to the market participants using the cost allocation formula discussed in section 6. A step-by-step example is shown below.

The reserve traded in the base case example is Regulating Reserve. The cost allocation is that generators and loads equally share the cost of the reserve (i.e., setting G_{REG}=50%). The load center is comprised of 4 distribution utilities with the following load MW levels:

Load 1 = 2,500 MW
Load 2 = 2,000 MW
Load 3 = 1,000 MW
Load 4 = 500 MW

We first compute the total cost of providing regulating reserve to the grid, which is the total REGRTA (or Regulating Reserve Trading Amount) for all reserve providers in the region.

$$\mathrm{Cost}^{h}_{\mathrm{REG}_a} = \sum_{k} \mathrm{REGRTA}^{a}_{i,h}$$

$COST_{REG}$ = (500MW x P100/MW) + (0MW x P100/MW) = P50,000

Again, G_{REG} = 50% or 0.5.

Since there are only two (2) generators, we can allocate the generators' share of the costs between these two generators using the formula:

$$\mathrm{Charge}^{\mathrm{Gen}_{a,i}}_{\mathrm{REG}_h} = \mathrm{Cost}^{h}_{\mathrm{REG}_a} \times \left[\frac{\mathrm{Energy}^{\mathrm{Gen,\ ex\text{-}ante}}_{a,i}}{\sum_{i} \mathrm{Energy}^{\mathrm{Gen,\ ex\text{-}ante}}_{a,i}} \right]^{h} \times G_{REG}$$

The generator allocations are then computed as:

$$\mathrm{Charge}_{\mathrm{REG}}^{\mathrm{GenA}} = 50,000 \times \left[\frac{6000}{6000+0} \right] \times 0.5 = 25,000.00$$

$$\mathrm{Charge}_{\mathrm{REG}}^{\mathrm{GenB}} = 50,000 \times \left[\frac{0}{6000+0} \right] \times 0.5 = 0.00$$

The customers' share in the reserve costs is allocated among each of the four (4) loads in the reserve cost recovery zone using the formula:

$$\mathrm{Charge}_{\mathrm{REG}_h}^{\mathrm{Load}_{a,j}} = \mathrm{Cost}_{\mathrm{REG}_a}^{h} \times \left[\frac{\mathrm{Energy}_{a,j}^{\mathrm{Load,\ ex\text{-}ante}}}{\sum_j \mathrm{Energy}_{a,j}^{\mathrm{Load,\ ex\text{-}ante}}} \right]^h \times \left(1 - G_{REG}\right)$$

The load allocations are then computed as:

$$\mathrm{Charge}_{\mathrm{REG}}^{\mathrm{Load1}} = 50,000 \times \left[\frac{2500}{6000} \right] \times (1-0.5) = 10,416.67$$

$$\mathrm{Charge}_{\mathrm{REG}}^{\mathrm{Load2}} = 50,000 \times \left[\frac{2000}{6000} \right] \times (1-0.5) = 8,333.33$$

$$\mathrm{Charge}_{\mathrm{REG}}^{\mathrm{Load3}} = 50,000 \times \left[\frac{1000}{6000} \right] \times (1-0.5) = 4,166.67$$

$$\mathrm{Charge}_{\mathrm{REG}}^{\mathrm{Load4}} = 50,000 \times \left[\frac{500}{6000} \right] \times (1-0.5) = 2,083.33$$

The cost allocation summary is tabulated in the table below. The values represent the reserve cost recovery charges to be billed to each resource as their share in the cost of having regulating reserve in the reserve cost recovery. It will be noted that the total cost allocation of each individual resource is equal to the total regulating reserve trading amount in the reserve area.

Base Case 1 - Cost Allocation

Generator	REG Charge
Gen A	P25,000.00
Gen B	P0.00
Load	**REG Charge**
Load 1	P10,4166.67
Load 2	P8,333.33
Load 3	P4,166.67
Load 4	P2,083.33
Total Allocated Costs	**P50,000**

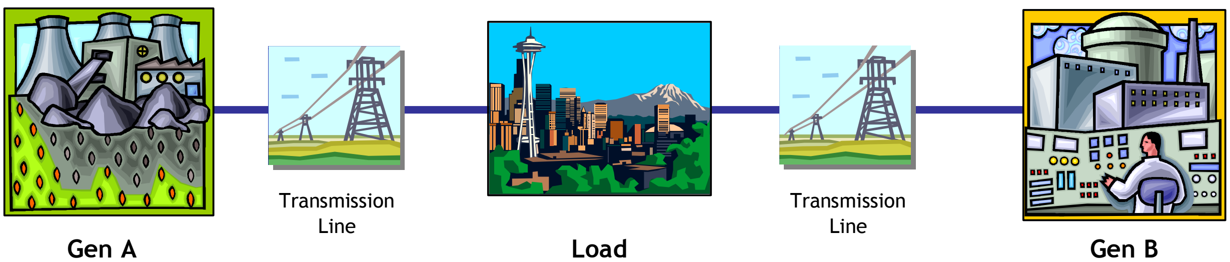
EXAMPLE 2 - Reserve Co-optimization affects Reserve Prices

In this example, dispatching a marginal amount of reserve results in the displacement of an equivalent marginal amount of energy. This marginal amount of energy schedule that was displaced must then be supplied by a more expensive supply of energy. Because of this, an opportunity cost must be included in the reserve price to take into account of this displacement. Losses and transmission line limits are not considered in this example to simplify analysis of this complex concept.

Location 2
Generator A
Energy: 7,000 MW @ P2,000/MWh
Reserve: 7,000 MW @ P5,000/MWh

Location1
Load Center
Demand = 6,000 MW
Reserve Requirement = 2,000 MW

Location3
Generator B
Energy: 6,000 MW @ P1,000/MWh
Reserve: 6,000 MW @ 100/MWh



Base Case 2 - Objective Function Cost

Energy	Q	P	Cost
Gen A Energy	2,000	2,000	4,000,000
Gen B Energy	4,000	1,000	4,000,000
Reserve	**Q**	**P**	**Cost**
Gen A Reserve	0	5,000	0
Gen B Reserve	2,000	100	200,000
		Total Objective Function Cost	**8,200,000**

Base Case 2 – Settlement

Energy	Sched	LMP	EAETA
Gen A Energy	2,000	2,000	4,000,000
Gen B Energy	4,000	2,000	8,000,000
Reserve	**Sched**	**ZRP**	**RTA**
Gen A Reserve	0	1,100	0
Gen B Reserve	2,000	1,100	2,200,000
		Total EAETA + RTA	**14,200,000**

Since Gen B is the cheapest generator for both energy and reserve, it will be fully dispatched for both energy and reserve first before dispatching Gen B. For the base case scenario, Gen B is already fully dispatched, 4,000MW for energy and 2,000MW for reserve. An additional 2,000MW from Gen A must then be scheduled for energy to satisfy the load demand of 6,000MW.

This is the optimal solution since maximizing reserve in Gen B is much cheaper than maximizing the energy schedule. Here, Gen A is the marginal plant for energy while Gen B is the marginal plant for reserve. Making Gen A as the marginal plant for reserve would mean a reserve cost of P5,000/MWh. This is avoided by allocating all reserve requirements from Gen B.

The costs are allocated to the market participants using the cost allocation formula discussed in section 6. A step-by-step example is shown below:

In this example, the reserve traded is Regulating Reserve. Generators and loads equally share the cost of regulating reserve (i.e., setting G_{REG}=50%). The load center is comprised of 4 distribution utilities with the following load MW levels:

Load 1 = 2,500 MW
Load 2 = 2,000 MW
Load 3 = 1,000 MW
Load 4 = 500 MW

The total cost of providing regulating reserve to the grid, which is the total REGRTA (or Regulating Reserve Trading Amount) for all reserve providers in the region is calculated as follows -

$$\mathrm{Cost}^{h}_{\mathrm{REG}_a} = \sum_k \mathrm{REGRTA}^{a}_{i,h}$$

$COST_{REG}$ = (0MW x P1100/MW) + (2000MW x P1100/MW) = P2,200,000

The share of the the two (2) generators in the reserve costs are computed using the formula:

$$\mathrm{Charge}^{\mathrm{Gen}_{a,i}}_{\mathrm{REG}_h} = \mathrm{Cost}^{h}_{\mathrm{REG}_a} \times \left[\frac{\mathrm{Energy}^{\mathrm{Gen,\ ex\text{-}ante}}_{a,i}}{\sum_i \mathrm{Energy}^{\mathrm{Gen,\ ex\text{-}ante}}_{a,i}} \right]^{h} \times G_{REG}$$

The generator allocations are then computed as:

$$\mathrm{Charge}^{\mathrm{GenA}}_{\mathrm{REG}} = 2,200,000 \times \left[\frac{2000}{2000 + 4000} \right] \times 0.5 = 366,666.67$$

$$\mathrm{Charge}^{\mathrm{GenB}}_{\mathrm{REG}} = 2,200,000 \times \left[\frac{4000}{2000 + 4000} \right] \times 0.5 = 733,333.33$$

The allocation of the costs to each of the four (4) loads in the reserve cost recovery zone is computed using the formula:

$$\text{Charge}_{\text{REG}_h}^{\text{Load}_{a,j}} = \text{Cost}_{\text{REG}_a}^{h} \times \left[\frac{\text{Energy}_{a,j}^{\text{Load, ex-ante}}}{\sum_j \text{Energy}_{a,j}^{\text{Load, ex-ante}}} \right]^{h} \times \left(1 - G_{REG}\right)$$

The load allocations are then computed as:

$$\text{Charge}_{\text{REG}}^{\text{Load1}} = 2{,}200{,}000 \times \left[\frac{2500}{6000} \right] \times (1 - 0.5) = 458,333.33$$

$$\text{Charge}_{\text{REG}}^{\text{Load2}} = 2{,}200{,}000 \times \left[\frac{2000}{6000} \right] \times (1 - 0.5) = 366,666.67$$

$$\text{Charge}_{\text{REG}}^{\text{Load3}} = 2{,}200{,}000 \times \left[\frac{1000}{6000} \right] \times (1 - 0.5) = 183,333.33$$

$$\text{Charge}_{\text{REG}}^{\text{Load4}} = 2{,}200{,}000 \times \left[\frac{500}{6000} \right] \times (1 - 0.5) = 91,666.67$$

The cost allocation summary is tabulated in the table below. The values represent the reserve cost recovery charges to be billed to each resource, as their payment for having regulating reserve in the reserve region. Note that the total cost allocation of each individual resource is equal to the total regulating reserve trading amount in the reserve region.

Base Case 2 - Cost Allocation

Generator	REG Charge
Gen A	P366,666.67
Gen B	P733,333.33
Load	**REG Charge**
Load 1	P458,333.33
Load 2	P366,666.67
Load 3	P183,333.33
Load 4	P91,666.67
Total Allocated Costs	**P2,200,000**

Case 2a – An incremental change in reserve requirement using Reserve Co-optimization

This scenario illustrates the effect of having a marginal increase in reserve requirement. This will provide an illustration on how energy and reserve are marginally priced. In this case, a marginal increase in reserve requirement would mean that one of the two generators must supply reserve. Having Gen A supply this marginal increase in reserve would be very expensive, at a price of P5,000/MWh. We assume an increase of 1 MW in reserve requirement. It is therefore optimal, or cheaper to bring down Gen B's energy schedule from 4,000MW to 3,999MW, leaving enough capacity to supply the increase in reserve requirement. This is shown in the table below:

Reserve Co-optimization: A 1 MW increase in reserve requirement

Objective Fxn Cost	Q	P	Cost		Settlement	Sched	LMP	EAETA
Gen A Energy	2,001	2,000	4,002,000		Gen A Energy	2,001	2,000	4,002,000
Gen B Energy	3,999	1,000	3,999,000		Gen B Energy	3,999	2,000	7,998,000
Objective Fxn Cost	**Q**	**P**	**Cost**		**Settlement**	**Sched**	**ZRP**	**RTA**
Gen A Reserve	0	5,000	0		Gen A Reserve	0	1,100	0
Gen B Reserve	2,001	100	200,100		Gen B Reserve	2,001	1,100	2,201,100
Total Objective Function Cost			**8,201,100**		**Total EAETA + RTA**			**14,201,100**

The increase in total objective function cost represents the cost of supplying the additional reserve requirement of 1 MW. The reserve price is at P1,100/MWh because of the additional cost of transferring energy schedule from the cheaper Gen B (P1,000/MWh) to Gen A (P2,000/MWh) in order to get cheaper reserve from Gen B.

Case 2b – No Reserve Co-optimization: An incremental change in reserve requirement being supplied by the next reserve marginal plant (Gen A)

If reserve co-optimization is not used and an additional 1 MW is procured from the more expensive Gen A (P5,000/MWh), it will be more expensive for the whole market. This is shown in the table below:

No Reserve Co-optimization: A 1 MW increase in reserve requirement

Objective Fxn Cost	Q	P	Cost		Settlement	Sched	LMP	EATA
Gen A Energy	2,000	2,000	4,000,000		Gen A Energy	2,000	2,000	4,000,000
Gen B Energy	4,000	1,000	4,000,000		Gen B Energy	4,000	2,000	8,000,000
Objective Fxn Cost	**Q**	**P**	**Cost**		**Settlement**	**Sched**	**ZRP**	**RTA**
Gen A Reserve	1	5,000	5,000		Gen A Reserve	1	5,000	5,000
Gen B Reserve	2,000	100	200,000		Gen B Reserve	2,000	5,000	10,000,000
Total Objective Function Cost			**8,205,000**		**Total EATA**			**22,005,000**

Since co-optimization is not used, reserve from Gen A will now be scheduled to supply the additional 1 MW increase in reserve requirement. The new marginal plant for reserve would become Gen A, setting the Zonal Reserve Price (ZRP) at a higher P5,000/MWh. This makes the total solution for case 2b very expensive compared to case 2a. Similarly, there are many possible ways to schedule this scenario. The examples cited here, however, that using reserve co-optimization is still the optimal and cheapest solution.

Using the same reserve cost recovery formula illustrated earlier, the resulting reserve cost recovery charges is summarized below:

Case 2a - Cost Allocation (Reserve Co-optimization)

Generator	REG Charge
Gen A	P367,033.43
Gen B	P733,516.58
Load	**REG Charge**
Load 1	P458,562.50
Load 2	P366,850.00
Load 3	P183,425.00
Load 4	P91,712.50
Total Allocated Costs	**P2,201,100.00**

Case 2b - Cost Allocation (No Reserve Co-optimization)

Generator	REG Charge
Gen A	P1,667,500.00
Gen B	P3,335,000.00
Load	**REG Charge**
Load 1	P2,084,375.00
Load 2	P1,667,500.00
Load 3	P833,750.00
Load 4	P416,875.00
Total Allocated Costs	**P10,005,000.00**

EXAMPLE 3 – Reserve Co-optimization affects Energy Prices

In this example, dispatching a marginal amount of energy would mean that an equivalent marginal amount of reserve schedule would be displaced. This marginal amount of reserve schedule displaced must then be supplied by a more expensive supply of reserve. Because of this, an opportunity cost must be included in the energy price to take into account of this displacement. Losses and transmission line limits are neglected in this example to simplify analysis of this complex concept.

Location 2
Generator A
Energy: 7,000 MW @ P1000/MWh
Reserve: 7,000 MW @ P100/MWh

Location1
Load Center
Demand = 6000 MW
REG Reserve Requirement = 2,000

Location3
Generator B
Energy: 6,000 MW @ P2,000/MWh
Reserve: 6,000 MW @ 200/MWh

Gen A | Transmission Line | Load | Transmission Line | Gen B

Base Case 3 - Objective Function Cost

Energy	Q	P	Cost
Gen A Energy	6,000	1,000	6,000,000
Gen B Energy	0	2,000	0
Reserve	**Q**	**P**	**Cost**
Gen A Reserve	1,000	100	100,000
Gen B Reserve	1,000	200	200,000
		Total Objective Function Cost	**6,300,000**

Base Case 3 - Settlement

Settlement	Sched	LMP	EAETA
Gen A Energy	6,000	1,100	6,600,000
Gen B Energy	0	1,100	0
Settlement	**Sched**	**ZRP**	**RTA**
Gen A Reserve	1,000	200	200,000
Gen B Reserve	1,000	200	200,000
		Total EAETA + RTA	**7,000,000**

Since Gen A is the cheaper generator for both energy and reserve, it will be fully dispatched for both energy and reserve first before dispatching Gen B. For the base case scenario, Gen A is already fully dispatched, 6,000MW for energy and 1,000MW for reserve. An additional 1,000MW from Gen B must then be scheduled for reserve to satisfy the reserve requirement.

The reserve costs are allocated to the market participants using the reserve cost recovery charge formula discussed in section 6. A step-by-step example is shown below:

In this example, the reserve traded is Regulating Reserve. Generators and loads equally share the cost of regulating reserve (setting G_{REG}=50%). The load center is comprised of 4 distribution utilities with the following load MW levels:

Load 1 = 2,500 MW
Load 2 = 2,000 MW
Load 3 = 1,000 MW
Load 4 = 500 MW

The total cost of providing regulating reserve to the grid, which is the total REGRTA (or Regulating Reserve Trading Amount) for all reserve providers in the region is computed as follows.

$$\mathrm{Cost}^{\mathrm{h}}_{\mathrm{REG_a}} = \sum_{\mathrm{k}} \mathrm{REGRTA}^{\mathrm{a}}_{\mathrm{i,h}}$$

$COST_{REG}$ = (1000MW x P200/MW) + (1000MW x P200/MW) = P400,000

Since G_{REG} = 50% or 0.5, the generators' reserve cost recovery charge is computed using the formula:

$$\mathrm{Charge}^{\mathrm{Gen_{a,i}}}_{\mathrm{REG_h}} = \mathrm{Cost}^{\mathrm{h}}_{\mathrm{REG}_a} \times \left[\frac{\mathrm{Energy}^{\mathrm{Gen,\ ex\text{-}ante}}_{\mathrm{a,i}}}{\sum_{\mathrm{i}} \mathrm{Energy}^{\mathrm{Gen,\ ex\text{-}ante}}_{\mathrm{a,i}}} \right]^{\mathrm{h}} \times G_{REG}$$

The two generators' reserve cost recovery charges are then computed as:

$$\mathrm{Charge}^{\mathrm{GenA}}_{\mathrm{REG}} = 400,000 \times \left[\frac{6000}{6000+0} \right] \times 0.5 = 200,000$$

$$\mathrm{Charge}^{\mathrm{GenB}}_{\mathrm{REG}} = 400,000 \times \left[\frac{0}{6000+0} \right] \times 0.5 = 0.00$$

The reserve cost recovery charge for each of the four (4) loads in the reserve cost recovery zone is computed using the formula:

$$\mathrm{Charge}_{\mathrm{REG}_h}^{\mathrm{Load}_{a,j}} = \mathrm{Cost}_{\mathrm{REG}_a}^{h} \times \left[\frac{\mathrm{Energy}_{a,j}^{\mathrm{Load,\ ex\text{-}ante}}}{\sum_j \mathrm{Energy}_{a,j}^{\mathrm{Load,\ ex\text{-}ante}}} \right]^h \times \left(1 - G_{REG}\right)$$

The load reserve cost recovery charges are then computed as:

$$\mathrm{Charge}_{\mathrm{REG}}^{\mathrm{Load1}} = 400{,}000 \times \left[\frac{2500}{6000}\right] \times (1-0.5) = 83,333.33$$

$$\mathrm{Charge}_{\mathrm{REG}}^{\mathrm{Load2}} = 40{,}000 \times \left[\frac{2000}{6000}\right] \times (1-0.5) = 66,666.67$$

$$\mathrm{Charge}_{\mathrm{REG}}^{\mathrm{Load3}} = 400{,}000 \times \left[\frac{1000}{6000}\right] \times (1-0.5) = 33,333.33$$

$$\mathrm{Charge}_{\mathrm{REG}}^{\mathrm{Load4}} = 400{,}000 \times \left[\frac{500}{6000}\right] \times (1-0.5) = 16,666.67$$

The cost allocation summary is presented in the table below. The values represent the charges to be billed to each resource, as their share in the cost of having regulating reserve in the reserve area or zone. Note that the total of the charges of each individual resource is equal to the total regulating reserve trading amount in the reserve area.

Base Case 3 - Cost Allocation

Generator	REG Charge
Gen A	P200,000.00
Gen B	P0.00
Load	**REG Charge**
Load 1	P83,333.33
Load 2	P66,666.67
Load 3	P33,333.33
Load 4	P16,666.67
Total Allocated Costs	**P400,000**

Case 3a – An incremental change in energy demand in the load using Reserve Co-optimization

Similar to the concept of marginal pricing shown in Cases 2a and 2b, this case illustrates the effect of having a marginal increase in energy demand in one of the loads and its effect on energy and reserve pricing.

In this case, a marginal increase in energy demand would mean that Generator B must be scheduled for energy, making it the marginal plant. Here, Load 1 was increased from 2,500 MW to 2,501 MW. However, the change in marginal plant would mean that energy prices would then be set at the new market clearing price of P2,000. Since the optimization solution knows that this is an expensive solution, it would opt to instead reduce Gen A's reserve schedule, transferring it to Gen B. This would give enough margin for additional energy to be scheduled. This can be seen in the table below.

Case 3a - Reserve Co-optimization: A 1MW increase in energy demand in the load

Objective Fxn Cost	Q	P	Cost		Settlement	Sched	LMP	EATA
Gen A Energy	6,001	1,000	6,001,000		Gen A Energy	6,001	1,100	6,601,100
Gen B Energy	0	2,000	0		Gen B Energy	0	1,100	0
Objective Fxn Cost	**Q**	**P**	**Cost**		**Settlement**	**Sched**	**ZRP**	**RTA**
Gen A Reserve	999	100	99,900		Gen A Reserve	999	200	199,800
Gen B Reserve	1,001	200	200,200		Gen B Reserve	1,001	200	200,200
Total Objective Function Cost			**6,301,100**		**Total EAETA + RTA**			**7,001,100**

The increase in total objective function cost represents the cost of supplying the additional increase in energy demand. This is reflected in the LMP of both generators. This opportunity cost is important because this means that the load customers would have to pay for the cost of transferring the reserve allocation from the cheaper Gen A (P100/MWh) to the more expensive Gen B (P200/MWh), in order to get cheaper energy from Gen A. Hence, the LMP is P1,100 instead of the marginal clearing price of P1,000.

Where Reserve Co-optimization is not used, the table below shows the corresponding calculations.

Case 3b - No Reserve Co-optimization: A 1 MW increase in energy demand in the load is supplied by the next marginal plant

Objective Fxn Cost	Q	P	Cost		Settlement	Sched	LMP	EATA
Gen A Energy	6,000	1,000	6,000,000		Gen A Energy	6,000	2,000	12,000,000
Gen B Energy	1	2,000	2,000		Gen B Energy	1	2,000	2,000
Objective Fxn Cost	**Q**	**P**	**Cost**		**Settlement**	**Sched**	**ZRP**	**EATA**
Gen A Reserve	1,000	100	100,000		Gen A Reserve	1,000	200	200,000
Gen B Reserve	1,000	200	200,000		Gen B Reserve	1,000	200	200,000
Total Objective Function Cost			**6,302,000**		**Total EATA**			**12,402,000**

Since Co-optimization is not used, energy from Gen B will now be scheduled to supply the additional 1 MW increase in demand. The new marginal plant would become Gen B, setting the LMP at an expensive P2,000/MWh. This makes the total solution much more expensive.

These two cases illustrate that the reserve co-optimized solution is the less expensive solution. Although there is no resulting increase in reserve costs in these cases, it should be noted that there is an increase in energy costs.

The resulting reserve cost recovery charges for Cases 3a and 3b are shown below:

Case 3a - Cost Allocation (Reserve Co-optimization)

Generator	REG Charge
Gen A	P200,000.00
Gen B	P0.00
Load	**REG Charge**
Load 1	P83,352.77
Load 2	P66,655.56
Load 3	P33,327.78
Load 4	P16,663.89
Total Allocated Costs	**P400,000.00**

Case 3b - Cost Allocation (No Reserve Co-optimization)

Generator	REG Charge
Gen A	P199,966.67
Gen B	P33.33
Load	**REG Charge**
Load 1	P83,352.77
Load 2	P66,655.56
Load 3	P33,327.78
Load 4	P16,663.89
Total Allocated Costs	**P400,000.00**

Appendix 2 – Detailed Formulation of the MDOM[27]

The *Market Dispatch Optimization Model* (the "MDOM") determines the schedules and prices for both energy and reserves. The objective of the MDOM is to maximize:

- Value of dispatched load based on demand bids,
- Minus the cost of dispatched generation based on generation offers,
- Minus the cost of dispatched reserves based on reserve offers,
- Minus the cost of constraint violation based on constraint violation coefficients.

The MDOM simultaneously solves the economic gain maximization problem for both energy and reserves in a *trading interval* and correspondingly produces energy and reserve schedules, nodal energy prices and area reserve prices for different reserve types.

The maximization problem is subject to different constraints, which include:

- System energy balance,
- Regional energy import/export constraints,
- Area reserve requirements constraints,
- Resource Energy Constraint,
- Reserve Resource Constraint,
- Reserve-Energy Constraint,
- Transmission Constraint

[27] The formulation presented in this Appendix **is a reproduction** of the detailed formulation of the Market Dispatch Optimization Model incorporated as Appendix III-1 in the ERC- approved Price Determination Methodology for the Philippine Wholesale Electricity Spot Market. It has been reproduced in this document for ease of reference only.

REQUIRED INPUTS TO THE MDOM

The MDOM receives input data from three sources, namely, the *System Operator*, the *trading participants* and the *Market Operator*.

1 System Operator

The *System Operator* sends its input data in the form of a flat-file to the Market Management System (MMS). These flat-files form part of the pre-processing process and become input parameters to the MDOM. The flat-files from the *System Operator* are described below.

1.1 System Snapshot

The *system snapshot* contains the latest power system condition provided by the *System Operator's* Energy Management System (the "EMS") at five-minute intervals to the MMS. The snapshot provides the level of power injected or withdrawn from the system at different market trading nodes which are monitored by remote telemetering units (RTU). It also provides the latest topology (i.e. configuration) of the power system as represented in the EMS topology and represented in the *Market Network Model* used by the MDOM.

1.2 Reserve Requirements

Regulation (REG), contingency (CON), dispatchable (DIS) and interruptible (ILD) reserves as determined by the *System Operator*. Reserve requirements are provided by the *System Operator* in accordance with the *Dispatch Protocol*[28]. The reserve requirements are used in the *area reserve constraints* of the MDOM.

1.3 Outage Schedule

The *outage schedule* contains the planned transmission line, equipment or facility outages as approved by the *System Operator*. The *outage schedule* is provided by the *System Operator* in accordance with the *Dispatch Protocol*. The outage schedule overrides information such as bids, offers and telemetry data. The outage schedule is used in the pre-processing to determine outage resources, so that the resources are not considered in the dispatch optimization process.

1.4 Contingency List

The contingency list contains pre-defined line or equipment outage condition to comply with the single outage contingency (N-1) criterion specified in the *System Security and Reliability Guidelines*. This criterion specifies that the grid shall

[28] See Annex E, *Dispatch Protocol*.

continue to operate in the normal state following the loss of one generating unit, transmission line, or transformer.

The list is used to implement contingency analysis in the dispatch optimization process and is used in pre-processing to include additional constraints in the system to comply with the single outage contingency (N-1) criterion. The contingency list is provided by the *System Operator* in accordance with the *Dispatch Protocol*.

1.5 Transmission Limits

The *transmission limits* contains the latest power transmission limits of transmission lines and transformers as determined by the SO. The transmission limit data imposed by the SO overrides the default transmission limit values of the *Market Network Model*. This also enables the SO to selectively override the transmission limit values of individual or groups of transmission lines for security and reliability purposes. In pre-processing, this allows the combination of both overridden and default transmission limit values for the *Market Network Model* to be used in the *transmission constraint* of the MDOM. Transmission limits are provided by the *System Operator* in accordance with the *Dispatch Protocol*.

1.6 Security Limits

The *security limits* contains the latest operating limits of generators and transmission line branch groups (including the high-voltage direct current (HVDC) link between Luzon and Visayas grids). The security limits are used by the System Operator to override prevailing resource information such as minimum stable loading (G_{min}[29]), and maximum stable loading (G_{max}) of generators and transmission line branch group flow limits for power system security purposes. This overriding constraint supersedes the registered resource limit information such as generator G_{min} and the maximum generation offered by the Trading Participant. After pre-processing, the overriding security limit values affect all related constraint equations that use resource limits and line or branch group flow limits. Security limits are provided by the *System Operator* in accordance with the *Dispatch Protocol*.

[29] Gmin is also known as Pmin and Gmax is also known as Pmax. Gmin and Gmax have been used only for consistency in the formulation notation and parameter name.

1.7 Load Pattern Data

The load pattern data contains the latest relative magnitudes of MW and MVar for each customer node used for the Similar Day Load Forecast Methodology[30] applied in the market projections (DAP and WAP workflows of the MDOM). Load patterns are provided by the *System Operator* in accordance with the *Dispatch Protocol*.

2 Trading Participants

2.1 Trading Participant Registration Data

Upon registration as *WESM trading participants*, they shall provide the following information which becomes default inputs to the MDOM, subject to confirmation by the SO:

- Generator limits (Minimum and maximum generator stable loading).
- Ramp-up and Ramp-down rates.
- Maximum response level for the relevant reserve type.

2.2 Generator Energy Offer

Generators shall submit their energy offer considering the following:

- At most ten (10) energy offer blocks per (aggregate) unit
- Shall be for a minimum block size of five (5) MW
- Monotonically increasing prices per block
- Ramp-Up rate (RRUP) and Ramp-Down rate (RRDN)
- Validity period of offers
- Operating range of the energy offer (upper and lower limit)

2.3 Resource Operating Reserve Offer

Resource (Generators or dispatchable loads) shall submit offers for operating reserves considering the following:

- The operating reserve type which may be regulation, contingency, dispatchable or interruptible load.
- At most three (3) operating reserve offer blocks per aggregate unit
- A minimum block size of one (1) MW
- Monotonically increasing operating reserve price per block
- Validity period of the operating reserve offer

[30] See *Load Forecasting Methodology*, Annex C.

2.4 Customer Demand Bid

Customers or loads that are classified as *dispatchable loads* may submit a maximum proportion of the forecasted/scheduled load which may be interrupted.

Dispatchable loads shall submit offers considering the following:

- At most, ten (10) energy offer blocks per take-off point.
- Minimum block size of one (1) MW
- Monotonically decreasing prices per block
- Validity period of bids

2.5 Customer Forecast

Customers may opt to submit forecast for any particular *trading interval* subject to the validation rules indicated in the *Load Forecasting Methodology*[31] for WESM.

3 Market Operator

3.1 Market Network Model

The *Market Network Model* is the electrical representation of physical transmission network elements, e.g. transmission lines, generators, transformers, loads and breakers. It is based on the transmission network data provided by the *System Operator* to the *Market Operator*.

3.2 Load Forecast

The *Market Operator* prepares nodal load forecasts used in the market projections and real-time dispatch through the Similar Day Load Forecast and Load Predictor methodologies, respectively, as described in the *Load Forecasting Methodology.*[32]

3.3 Constraint Violation Coefficient

Constraint Violation Coefficients (the “CVC’s”) correspond to the constraint penalty values inputted by the Market Operator to the MDOM. CVCs are ranked and graded such that if constraints are not satisfied, the MDOM will still continue to find a solution but reflecting the CVC prices in the nodal prices.

- Deficit Interruptible Load Reserve
- Deficit Dispatchable Reserve
- Deficit Regulating Reserve
- Deficit Contingency Reserve

[31] See Annex C, *Load Forecasting Methodology*.
[32] See Annex C, *Load Forecasting Methodology*.

- Nodal Value of Lost Load
- Contingency
- Under-generation/Over-generation
- Base Case Constraint
- Transmission Constraint Group (TCG) constraint

OUTPUT OF THE MDOM

The optimization process will produce the following outputs:

- System Marginal Price
- Generation Schedules
- Dispatchable Load Schedule
- Regulation Reserve Schedule
- Contingency Reserve Schedule
- Dispatchable Reserve Schedule
- Interruptible Load Reserve Schedule
- Generator Node Energy Price
- Load Node Energy Price
- Regional Reserve Prices for each Reserve Category
- Transmission Line flows
- Transmission Line and System Losses

GLOSSARY OF FORMULATION INDICES, VARIABLES AND PARAMETERS

INDICES

The following indices are used

k indexes reserve types

k=1 refers to regulating reserve type

k=2 refers to contingency reserve type

k=3 refers to dispatchable reserve type

k=4 refers to interruptible load reserve type

i indexes resources (generators or dispatchable loads)

j indexes resource offers or bids

a indexes energy and reserve areas

l indexes transmission lines

PARAMETERS

E_d	Total number of dispatchable loads with energy demand bids.
E_g	Total number of generators with energy offers.
E_r	Total number of resources (generators or dispatchable load) with reserve offers.
N_k	Total number of reserve resources for each reserve type "*k*"
$PDB_{i,j}$	The price per quantity element of the j^{th} Energy Bid block of the i^{th} Dispatchable Load.
$PG_{i,j}$	The price per quantity element of the j^{th} Energy Offer block of the i^{th} Generator (or dispatchable load).
$PR_{i,j,k}$	The price per quantity element of the j^{th} Reserve Offer block of the k^{th} Reserve Type of the i^{th} Resource.
CVC_{UG_j}	The j^{th} price of the Under Generation Penalty Cost Function for system energy balance corresponding to the amount of Q_{UG}.
CVC_{OG_j}	The j^{th} price of the Over Generation Penalty Cost Function for system energy balance corresponding to the amount of Q_{OG}.

$CVC_{R_{j,k,a}}$	The j^{th} price of the Reserve Penalty Cost Function for reserve type *k in reserve area a* corresponding to the amount of $Q_{R_{k,a}}$.
$CVC_{TCG_{j,a}}$	The j^{th} price of the Transmission Constraint Group (TCG) Penalty Cost Function corresponding to import/export constraint at area *a*.
$CVC_{BC_{j,l}}$	The j^{th} price of the Base Case Penalty Cost Function for normal line limit violations of any line *l*.
$CVC_{C_{j,l}}$	The j^{th} price of the Contingency Penalty Cost Function for contingency line limit violations of any line *l*.
$R^{req}{}_{k,a}$	The MW Reserve requirement of reserve type k in *reserve area a*.
$G_{max(t),i}$	The time-varying input high limit for each generator i or the negative of the time-varying input maximum load for each dispatchable load i.
$G_{min(t),i}$	The time varying input low limit for each generator i or Zero for each dispatchable load i.
$G_{\min,RRDN,i}$	Ramp Limited minimum MW level of generator (or dispatchable load) resource "*i*".
$G_{\max,RRUP,i}$	Ramp Limited maximum MW level of generator (or dispatchable load) resource "*i*".
$G_{\max,i,j}$	Maximum generator offer tranche j for resource *i*.
$PD_{i,a}$	The MW quantity of the i^{th} Load in area *a*.
$R_{offer\max,i,k,a}$	Maximum reserve limit from the offer for category *k* for resource *i* in reserve area a.
$R_{ramp\max,i,k,a}$	Maximum reserve ramp-time-limited for category *k* of resource *i* in reserve area a.
$ImportLimit_a$	Import MW limit of area *a* corresponding to the HVDC line MW flow limit.
$ExportLimit_a$	Export MW limit of area *a* corresponding to the HVDC line MW flow limit.
$RRUP_i$	Ramp-up rate of generator (or dispatchable load) resource *i*.
$RRDN_i$	Ramp-down rate generator (or dispatchable load) resource *i*.
$G_{min,i}$	Minimum stable loading of generator *i*. (also known as Pmin)
$G_{max,i}$	Maximum registered capacity of generator *i*.

$[B]$	A matrix of transmission network admittance.
$[H]$	A matrix of line-node references (with +/- admittance elements for both ends of a line).
$[P_L]$	A vector of transmission line limits.
B_l	Admittance of the line *l*.
$P_{L,l}$	Transmission line limit of line *l*.
$[a]$	Sensitivity Coefficient matrix defining the variation of line flows as a function of nodal injection changes calculated by NSA and supplied to NCD.

VARIABLES

$G_{i,j}$	The MW quantity of the j^{th} Energy Offer block of the i^{th} Generator (or dispatchable load).
$R_{i,j,k}$	The MW quantity of the j^{th} Reserve Offer block of the k^{th} Reserve Type of the i^{th} Resource.
$DB_{i,j}$	The MW quantity of the "j^{th}" Energy Bid block of the i^{th} Dispatchable Load.
CVP	The sum of penalty costs for soft constraints violations based on the constraint violation coefficients.
Q_{UG}	The MW quantity by which the system load exceeds the system generation.
Q_{OG}	The MW quantity by which the system generation exceeds the system load.
$Q_{R_{k,a}}$	The MW quantity by which the operating reserve requirement of type *k* for *reserve area a* was not satisfied.
Q_{TCG_a}	The MW quantity by which the import/export limit of corresponding Transmission Constraint Group (TCG) for area *a* is violated.
Q_{BC_l}	The MW quantity by which the line limit of any line *l* is violated.
Q_{C_l}	The MW quantity by which the contingency line limit of any line *l* is violated.
$P_{Loss,a}$	Sum of all network losses in area *a*.

$Q_{TCG_a,import}$	The MW value of the import limit that was violated (slack variable for energy import constraint for area a).
$Q_{TCG_a,export}$	The MW value of the export limit that was violated (slack variable for energy export constraint for area a).
G_i	The MW level of generator resource *i* that is $G_i = \sum_j G_{i,j}$ where *j* denotes the offer tranche.
$R_{i,k}$	Reserve schedule for resource *i* of reserve type *k* in *reserve area* a that is $R_{i,k} = \sum_j R_{i,j,k}$ where *j* denotes the offer(or bid) tranche.
$R_{\max,i,k}$	Maximum Reserve contribution for reserve type *k* of resource *i* in reserve area a which is the minimum of $R_{offer\max,i,k,a}$ and $R_{ramp\max,i,k,a}$
DB_i	The MW schedule of Dispatchable Load *i* that is $DB_i = \sum_j DB_{i,j}$ where *j* corresponds to the bid tranche.
P_n	Net power injection for each node.
$Pflow_{m,n}$	Power flow in the line between nodes m and n.
$[\theta]$	A matrix of nodal angles.
$[P_n]$	A matrix of nodal power injection
$\Delta\theta_l$	Angle difference between sending and receiving nodes for line l.
$a_{i,l}$	Sensitivity coefficient defining the variation of line flow in line *l* as a function of nodal injection changes by resource *i* calculated by in NSA and supplied to NCD.

OBJECTIVE FUNCTION

Maximize the *Economic Gain* from trade, where:

$$\text{Economic Gain} = \left\{ \sum_{i}^{E_D} \sum_{j} \left[\left(DB_{i,j}\right)\left(PDB_{i,j}\right) \right] - \sum_{i}^{E_G} \sum_{j} \left[\left(G_{i,j}\right)\left(PG_{i,j}\right) \right] - \sum_{i}^{E_R} \sum_{k}^{N_K} \sum_{j} \left[\left(R_{i,j,k}\right)\left(PR_{i,j,k}\right) \right] - (CVP) \right\}$$

i $\in$ resources (generators and dispatchable loads)
j $\in$ energy and reserve offer blocks
k $\in$ reserve types

CONSTRAINT VIOLATIONS PENALTY COST

The Constraint Violation Penalty Cost is defined as follows:

$$\text{CVP} = \left\{ \begin{array}{l} CVC_{UG_j}(Q_{UG}) + CVC_{OG_j}(Q_{OG}) \\ + \sum_{k} \sum_{a} \left[CVC_{R_{j,k,a}} \left(Q_{R_{k,a}} \right) \right] + \sum_{a} \left[CVC_{TCG_{j,a}} \left(Q_{TCG_a} \right) \right] \\ + \sum_{l} \left[CVC_{BC_{j,l}} \left(Q_{BC_l} \right) \right] + \sum_{l} \left[CVC_{C_{j,l}} \left(Q_{C_l} \right) \right] \end{array} \right\}$$

j $\in$ constraint violation coefficient block
k $\in$ reserve types
a $\in$ energy and reserve area
l $\in$ transmission lines

OPTIMIZATION CONSTRAINTS

In the optimization process, the following constraints must be observed.

1. System Energy Balance Constraint

$$\sum_{i} \sum_{j} G_{i,j} + Q_{UG} = \sum_{i} PD_i + \sum_{a} P_{Loss,a} + Q_{OG}$$

If no under-generation or over-generation is present, Q_{UG} and Q_{OG} are zero. The two terms are also known as "slack-variables" in optimization theory.

2. Regional Energy Import/Export Constraints

The amount of energy a region could import/export must not violate its scheduled resource and load.

$$\sum_{i}\sum_{j} G_{i,j,a} - \sum_{i} PD_{i,a} - P_{Loss,a} + Q_{TCG_a,import} \geq ImportLimit_a$$

and

$$\sum_{i}\sum_{j} G_{i,j,a} - \sum_{i} PD_{i,a} - P_{Loss,a} + Q_{TCG_a,export} \geq ExportLimit_a$$

With no import/export violation, $Q_{TCG_a,import}$ and $Q_{TCG_a,export}$ are zero.

3. Area Reserve Requirement Constraint

The *reserve requirement* for each area shall only be satisfied by local generators on each specified area "*a.*"

For Regulating Reserve requirement in reserve area *a*.

$$\sum_{i}\sum_{j} R_{i,j,k} + Q_{R_k,a} = R^{req}{}_{k,a} \text{ , } k=1 \text{ and } i \in \text{facilities in reserve area } a$$

For Contingency Reserve requirement in reserve area *a*.

$$\sum_{i}\sum_{j} R_{i,j,k} + Q_{R_{k,a}} = R^{req}{}_{k,a} \text{ , } k=2 \text{ and } i \in \text{facilities in reserve area } a$$

For Dispatchable Reserve requirement in reserve area *a*.

$$\sum_{i}\sum_{j} R_{i,j,k} + Q_{R_{k,a}} = R^{req}{}_{k,a} \text{ , } k=3 \text{ and } i \in \text{facilities in reserve area } a$$

For Interruptible Load Reserve requirement in reserve area *a*

$$\sum_{i}\sum_{j} R_{i,j,k} + Q_{R_{k,a}} = R^{req}{}_{k,a} \text{ , } k=4 \text{ and } i \in \text{facilities in reserve area } a$$

4. Resource Energy Constraint

For a dispatchable resource (i.e. generator or dispatchable load), a number of limits are applied which covers the ramp capability to satisfy its energy schedule:

- Maximum operating capability denoted by $G_{max,RRUP,i,(t)}$
- Minimum stable generation denoted by $G_{min,RRDN,i,(t)}$
- Ramp-Up Rate denoted by RRUP
- Ramp-Down Rate denoted by RRDN

The high and low operating limits ($G_{max,RRUP,i,(t)}$, $G_{min,RRDN,i,(t)}$) are the generating limits used for a given time point (t). They are a function of the operating capability, minimum generation and ramp rates.

Where:

$$G_{max,RRUP,i\ (t+1)} = G_{max,RRUP,\ i\ (t)} + \Delta t * RRUP$$

$$G_{min,RRDN,\ i\ (t+1)} = G_{min,RRDN,\ i\ (t)} - \Delta t * RRDN$$

$$\Delta t = 1\ hour$$ [33]

The Resource Energy Constraint, therefore, is:

$$G_{\min,RRDN,i} \le G_i \le G_{\max,RRUP,i}$$

where

$$G_i = \sum_j G_{i,j} \quad j \in \text{generator offer tranche of resource } i$$

and the size of each offer tranche is respected:

$$G_{i,j} \le G_{\max,i,j}$$

In addition to ramping limits the Resource Energy Constraint is implemented in conjunction with two further sources of constraint that must be respected:

- The maximum offer quantity.
- The stable minimum and maximum operating limits.

[33] At present the trading interval is set at 1 hour. The MMS may be configured in the future to operate at a shorter trading interval.

Respecting the participant offers for resource i gives the constraint:

$$G_i \leq G_{max,i,J}$$

Where J is the highest offer made for resource i.

The minimum stable operating limit must be always equal to the registered minimum stable operating limit, $G_{min,i}$. Hence the constraint:

$$G_{min,i} \leq G_i \leq G_{max,i}$$

Where the resource is also offering reserves, this energy constraint is replaced by a constraint that combines the energy and reserves limits. This will be discussed in later sections.

5. Reserve Resource Constraint

Reserve schedule from a generator depends on its relationship with energy and reserve effectiveness factors.

For a generator, its maximum reserve contribution is capped by $R_{\max,i,k}$ the maximum reserve contribution for reserve type *k* of resource *i*. The maximum contribution is the minimum of $R_{offer\max,i,k,a}$ (maximum reserve limit from the resource *i* offer) and $R_{ramp\max,i,k,a}$ (ramp-limited capacity of resource *i*). The reserve resource constraint therefore is:

$$R_{i,k} \leq R_{\max i,k} = \min\left(R_{offer\max,i,j,k,a}, R_{ramp\max,i,k,a}\right)$$

The size of each offer tranche is respected:

$$R_{i,j,k} \leq R_{max,i,j,k}$$

$$R_{i,k} \leq \Sigma R_{i,j,k}$$

6. Reserve-Energy Generation Constraint

The energy and reserve schedules are “co-optimized” by observing the following constraints.

6.1. Regulation Headroom Constraints

The head-room constraint is imposed on regulating reserve resources (k=1) in order to schedule the energy output (G_i) of the generator resource "*i*" with consideration of its minimum stable generation limit ($G_{min,i}$).

$$G_i - R_{i,k=1} \geq G_{\min,i}$$

6.2. Reserve and Energy Constraints

The maximum stable generation of generator resource "*i*" must not be violated in the energy and reserve scheduling by imposing the following constraint.

$$(R_{i,k=1} + R_{i,k=2} + R_{i,k=3}) + G_i \leq G_{\max,i}$$

This is the same for the interruptible load reserve category *(ILD, k=4)*. Interruptible load reserve schedule for customer *i* should be less than or equal to energy schedule for dispatchable load (DB) for customer *i*.

$$R_{i,k=4} \leq DB_i$$

7. Transmission Constraint

Transmission constraints are derived from the nodal energy balance constraints and line flow constraints. The nodal energy balance is defined as:

$$[P_n] = [B][\theta]$$

The line flow constraint for any line "*l*" from bus *m* to bus *n* is defined as

$$Pflow_{m,n} \leq P_{L,l}$$

While the line flow constraints are defined as,

$$[H][\theta] \leq [P_L]$$

For an individual transmission line *l*, the flow constraint has the following form:

$$B_l \Delta\theta_l \leq P_{L,l}$$

Substituting the nodal power balance equation into the line flow constraints equation and defining sensitivity matrix [a] as $[a] = [H][B]^{-1}$, the line flow constraints, in sensitivity form, is

$$[a][P_n] \leq [P_L]$$

For an individual transmission line l, the flow constraint, in sensitivity form, is expressed as

$$\sum_{i} a_{i,l}\ P_i \ \leq P_{L,l} \quad \text{where } P_i = G_i ,$$

Appendix 3 - Glossary of Terms[34]

Terms	Definition
A	
Act	Refers to republic Act no. 9136 also known as the "Electric Power Industry Reform Act of 2001".
Administered Price Cap	A price cap imposed by the *Market Operator* to the *trading participants* during market suspension and intervention to be used for settlements. Said price cap shall be developed and published by the *Market Operator* for ERC approval.
Algorithm	The process/processes applied by the MDOM in computing the dispatch schedules and prices.
Ancillary Services Provider	A person or entity providing ancillary services and registered as such with the *Market Operator*.
B	
Bilateral Contract	A contract between parties, the net effect of which is that a defined quantity of electricity has been sold by one party to another, at a particular node.
C	
Central Dispatch	The process of scheduling by the *Market Operator* and issuing direct instructions to electric power industry participants by the *System Operator* to achieve the economic operation of the transmission system while maintaining its quality, stability, reliability and security.
Constraint	A limitation on the capability of any combination of network elements, loads generating units or ancillary service providers such that it is, or deemed by the *System Operator* to be, unacceptable to adopt the pattern of transfer, consumption, generation or production of electrical power or other services that would be most desirable if the limitation were removed.
Constraint violation	A constraint is violated when the loadings of network elements, loads generating units or ancillary services providers involved in that constraint combine in such a way as to exceed the limit specified by that constraint.
Constraint Violation Coefficient Price	The price associated with the *Constraint Violation Coefficients*.

[34] The Glossary of Terms presented in this Appendix **is a reproduction** of the Glossary of Terms in the ERC- approved Price Determination Methodology for the Philippine Wholesale Electricity Spot Market. It has been reproduced in this document for ease of reference only

Terms	**Definition**
Constraint Violation Coefficients	Coefficients set by the *Market Operator* in accordance with *WESM Rules* clause 3.6.2. The *Market Operator* is to ensure that, if constraints shall be violated, such violation will occur in appropriate priority order.
Contingency List	Contains the definition of credible contingencies for power system security analysis. It includes a list of pre-defined outage scenarios that are most likely to occur in the system in faulty conditions.
Customer Load Forecast	The hourly demand forecast provided by customers at their respective market trading node as defined in the *Market Network Model*, which forecast is to be used in the determination of market projections and real time dispatch in accordance with WESM timetable.
Customer Pricing Zone	A *zone* within which all *customers* will face the same price for electricity consumed, as published by the *Market Operator* in accordance with *WESM Rules* clause 3.2.3.1.
<u>**D**</u>	
Day Ahead Dispatch Process	A pre-dispatch process covering the results obtained in the day-ahead projections.
Demand Bid	A standing bid or market bid to buy electricity submitted, or such bid revised by a customer in accordance with clauses 3.5.6, 3.5.9, 3.5.12, or 3.5.13, and containing the information specified in Appendix A1 of the *WESM Rules*.
Dispatch	The act by which the *System Operator* initiates all or part of the response offered or bid by a scheduled generating unit or scheduled load in accordance with clause 3.8.2 of WESM rules.
Dispatch Schedule	The target loading levels in MW for each scheduled generating unit or scheduled load and for each reserve facility for the end of that trading interval, determined by the *Market Operator* through the use of market dispatch optimization model in accordance with *WESM Rules* clause 3.8.1.
Dispatchable load	A load which is able to respond to dispatch instructions and so may be treated as a scheduled load in the dispatch process.
DOE	The Department of Energy which is government agency created pursuant to Republic Act No. 7638 and whose expanded functions are provided in the Act.
<u>**E**</u>	
Economic gain	The benefit that will be received by consumers in the economic dispatch optimization.

Terms	**Definition**
Economic Rental	Means, for a *constraint* in the *market dispatch optimization model* where the constraint is in linear programming canonical form (that is, for a maximizing optimization model, the sum of the variable terms is less than or equal to the constant term), the *shadow price* of the *constraint* multiplied by the constant term of said *constraint*.
Emergency	An event or situation described in clauses 6.3.1.1 and 6.3.1.2 of the *WESM Rules*
End-user	Any person or entity requiring the supply and delivery of electricity for its own use.
Energy	Generally, active energy and/or reactive energy. For purposes of this document, means active energy only.
Energy Balance Equation	An equation determined by the *Market Operator* in accordance with *WESM Rules* clause 3.6.1.4 (c), representing the balance between generation, load and transmission flows at a particular node of the *market network model*.
Energy Management System (EMS)	A system of computer-aided tools used by the *System Operator* to monitor, control, and optimize the performance of the generation and transmission systems.
Energy Regulatory Commission	The independent, quasi-judicial regulatory body created under the *Act*, otherwise ERC or Commission.
Ex-Ante	A matter determined in relation to a *trading interval* before that *trading interval* commences.
Ex-Ante Dispatch Process	Process where *dispatch* targets is set for the end of a *trading interval*, immediately preceding the beginning of that *trading interval*.
Ex-Ante Energy Settlement Price	The *ex-ante nodal energy price* or the *ex-ante zonal reserve price,* as may be appropriate, determined in accordance with clause 3.10.2 or clause 3.10.3, both of the *WESM Rules*.
Ex-Ante Energy Settlement Quantity	The gross amount determined by the *Market Operator* in accordance with *WESM Rules* clause 3.13.5, and adjusted for *bilateral contracts* in accordance with clause 3.13.7.
Ex-Ante Energy Trading Amount	Determined as the *ex-ante energy settlement price* for a node in a *trading interval* multiplied by the *ex-ante energy settlement quantity* (in MWh) for that node in that *trading interval*.
Ex-Ante Nodal Energy Price	The price determined by the *Market Operator* for a particular *market network node* and *trading interval*, immediately prior to commencement of that *trading interval,* directly from the *dispatch optimization* for that *trading interval* in accordance with *WESM Rules* clause 3.10.2.

Terms	Definition
Ex-Post	A matter determined in relation to a *trading interval* after that *trading interval* concludes.
Ex-Post Dispatch Process	Process where *dispatch* is set for the end of a *trading interval,* immediately after the *trading interval* concludes.
Ex-Post Energy Settlement Price	The *ex-post nodal energy price* or the *ex-post zonal energy price,* as appropriate, determined in accordance with *WESM Rules* clause 3.10.9
Ex-Post Energy Settlement Quantity	The amount determined by the *Market Operator* accordance with *WESM Rules* clause 3.13.6.
Ex-Post Energy Trading Amount	The *ex-post energy settlement price* for a node in a *trading interval* multiplied by the *ex-post energy settlement quantity* for that node in that *trading interval* (in MWh); minus the *ex-post energy settlement price* for that node in that *trading interval* multiplied by the *ex-ante energy settlement quantity* for that node in that *trading interval* (in MWh).
Ex-Post Nodal Energy Price	The price determined by the *Market Operator* for a particular *market node* and *trading interval,* after the end of that *trading interval* in accordance with *WESM Rules* clause 3.10.6.
F	
Facility	A generic term associated with apparatus equipment, buildings and necessary supporting resources for the generation, transmission, supply, sale and consumption of electricity.
Financial Transmission Right	The right to financial compensation based on differences between *nodal energy prices* at different *market trading nodes*.
Formulation	A mathematical representation of an optimization model.
G	
Generating facility	A facility, consisting of one or more *generating units*, where electric energy is produced from some other form of energy by means of a suitable apparatus.
Generating unit	A single machine generating electricity and all the related equipment essential to its functioning as single entity and having a nameplate rating of one (1) MW or more.
Generation	The production of electrical power by converting one form of energy to another in a *generating unit*.
Generation offer	A standing offer, or *market offer* to supply electricity, submitted or revised by a generation company in accordance with *WESM Rules* clauses 3.5.5, 3.5.9, 3.5.10 or 3.5.11.
Generator node	A *market trading node* at which electricity will normally be sold to the *spot market* and which is classified as a *generator node* in accordance with *WESM Rules* clause 3.2.2.2.

Terms	**Definition**
Grid	The high voltage backbone system of interconnected transmission lines, substations and related facilities, located in each of Luzon, Visayas and Mindanao, or as may otherwise be determined by the ERC in accordance with Section 45 of the Act.
Gross Pool	The dispatch model where all energy is traded through the WESM.
I	
Intervention	A measure taken by the *System Operator* when the grid is in extreme state condition as established in the Philippine Grid Code arising from a threat to system security, force majeure or emergency. During such event, the *administered price cap* shall be used for settlements In the WESM
L	
Linear Programming	A mathematical procedure for minimizing or maximizing a linear function of several variables, subject to a finite number of linear restrictions on these variables.
Line rental	The economic rental arising from the use of a *transmission line*, calculated as the difference in value between flows out of the receiving node of the line and flows into the sending node, in accordance with *WESM Rules* clause 3.13.12.
Load	The amount of energy consumed in a defined period via node.
Load Forecast	Has the same meaning as net load forecast
Load Pattern	Represents the relative magnitudes of MW and MVar values on individual loads. The load pattern data is used to distribute system/zonal load to individual loads, i.e. nodal load.
Locational Marginal Price (LMP)	This is the marginal value of the objective function at each bus at the solution of the optimization problem.
M	
Marginal Plant	The generating unit or plant whose price offer corresponds to the system marginal price for a given *trading interval*.
Market Dispatch Optimization Model (MDOM)	The optimization model which contains the mathematical algorithm approved by the *PEM Board* to be used for the purposes of determining dispatch schedules and energy prices, and preparing market projections based on the *price determination methodology* approved by the ERC.
Market Network Model	A mathematical representation of the power system, which will be used for the purpose of determining dispatch schedules and energy prices, and preparing market projections.

Terms	**Definition**
Market Offer	A generation offer for a particular *trading interval* of a particular trading day in the current market horizon, whether formed from a standing offer in accordance with *WESM Rules* clause 3.5.10 or revised by the relevant *trading participant* in accordance with *WESM Rules* clause 3.5.11.
Market Operator	The entity responsible for the operation of the *spot market* governed by the *PEM Board* in accordance with *WESM Rules* clause 1.4 which, for the avoidance of doubt, is the Autonomous Group Market Operator (the "AGMO") for a period of twelve months from the *spot market* commencement date and thereafter the entity to which the functions, assets and liabilities of the AGMO are transferred in accordance with Section 30 of the *Act*.
Market Price	A generic term covering prices for *energy* and *reserve, ex-ante or ex-post, nodal or zonal,* as appropriate.
Market Suspension	An event wherein the ERC declares the operation of the spot market to be suspended in cases of natural calamities or national and international security emergencies. During such event, the *administered price cap* shall be used for settlements in the WESM.
Market Trading Nodes	Those nodes at which electricity will be either bought or sold from the spot market, defined in accordance with clause 3.2.2 of the *WESM Rules*.
Market Transaction	A sale or purchase of electricity, or other services, made through the *spot market*.
Meter	A device which measures and records the consumption or production of electricity.
Metering Point	The point of physical connection of the device measuring the current in the power conductor.
MW block	Represents the quantity portion of the market offers/bids of the *trading participants*.
<u>N</u>	
Net Load Forecast	A forecast, prepared in accordance with the procedures developed under *WESM Rules* clause 3.5.4, of the *load,* net of any non-scheduled generation, to be matched, along with any *scheduled load,* by generation from scheduled *generation facilities.*

Terms	Definition
Net Settlement Surplus	The *settlement surplus* remaining after all *market transactions* have been accounted for. This remainder is assumed to be attributable to *economic rentals* arising from other binding constraints. Also termed settlement surplus
Network Data	These are electrical parameters used to represent the transmission system or network.
Network Service Provider	A person or entity that engages in the activity of owning, controlling, or operating a *transmission or distribution system* and who is registered with the *Market Operator in* that capacity under *WESM Rules* clause 2.3.4.
Nodal Energy Price	The energy price at a *node* determined *ex ante* or *ex-post*. This is also the Locational Marginal Price (the "LMP") in the WESM.
Node	A *connection point* on a *network,* or junction point within a *network* model, whether physical or notional.
Non Dispatchable Load Energy	The MW energy requirement of non-dispatchable load.
<u>O</u>	
Objective Function	Function to be minimized or maximized, representing, e.g., cost or profit.
Opportunity Cost	The economic loss suffered by some party as a result of losing an opportunity, such as the opportunity to sell energy in the *spot market*.
Outage Schedules	Schedule for shutting down or de-rating of generation and transmission facilities
Over generation	*Constraint Violation Coefficient* for the system condition whereby the generation in the system exceeds the total demand. This also corresponds to system energy balance constraint. This condition is also known as excess generation.
<u>P</u>	
PEM Board	The group of directors serving from time to time on the board that is responsible for governing the *WESM*.
Plant	Any equipment involved in generating, utilizing or transmitting electrical energy.

Terms	Definition
Power System	The integrated system of transmission and distribution networks for the supply of electricity in the Philippines.
Price Curve	The price curve of a generator energy offer is defined by up to ten (10) blocks as follows: the nth block (P/MW) defines the price between the nth and (n+1st) MW points. The last non-zero MW break point and slope (P/MW) defines the price until the maximum generation. The blocks must be monotonically non-decreasing.
Price Determination Methodology	A document which provides specific details as to how dispatch schedules and locational marginal prices (nodal prices) are calculated in the Market Dispatch Optimization Model (MDOM) as provided in clause 3.6 of the *WESM Rules*.
R	
Receiving node	For a *transmission line,* the *node* from which there is a net flow of electricity out of that line in a particular *trading interval* to be accounted for in determining the *line rental,* in accordance with *WESM Rules* clause 3.13.12. For a *transmission right,* the *node* to which the issuer of the *transmission right* is deemed to guarantee transfer of electricity, to be advised to the *Market Operator* in accordance with *WESM Rules* clause 3.13.2.
Regional Reserve Price	The price for *reserve* in a particular *supply* zone, and *trading interval*, determined in accordance with *WESM Rules* clause 3.10.10. Also known as zonal reserve price.
Reserve Category	A particular kind or class of reserve as provided for in *WESM Rules* clause 3.3.4.2. These are regulating, contingency, dispatchable and interruptible load reserves.
Reserve Cost Recovery Charge	Charges to recover the costs incurred in purchasing reserve, to be determined by a formula approved by the ERC.
Reserve Cost Recovery Zone	A zone within which reserve cost recovery charges may be recovered to meet each locationally specific requirement.
Reserve Offer	A *standing offer* or *market offer* to supply reserves, submitted or revised by a customer or a generation company in accordance with *WESM Rules* clauses 3.5.7, 3.5.8, 3.5.10 or 3.5.11.
Reserve Requirements	Demands for regulation reserve, contingency reserve and other relevant types of reserves. They are determined based on system loading, maximum generator tripping and other considerations

Terms	**Definition**
Reserve Region	A zone of the *power system* from which a particular reserve category can be supplied to meet a particular locationally specific requirement.
Run	A particular instance of the *market dispatch optimization model* performed for a particular *trading interval*, or a set of such instances of the *model* performed for all the *trading intervals* in a market horizon.
<u>S</u>	
Security-constrained economic dispatch	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.
Scenario	A *net load forecast* covering a market horizon.
Scheduled Load	A *load* which is able to respond to *dispatch* instructions, and has been bid into the *spot market* using a *demand bid* and so may be scheduled and dispatched via the scheduling and dispatch procedures.
Security limits	Limits imposed by the *System Operator* on generation and transmission equipment to maintain system security and reliability.
Self-commitment	The principle whereby participants assume full responsibility for how and when their plants are operated.
Sending node	For a *transmission line*, the *node* into which there is a net flow of electricity out of that line in a particular *trading interval* to be accounted for in determining the *line rental* in accordance with *WESM Rules* clause 3.13.12. For a *transmission right*, the *node* from which the issuer of the transmission right is deemed to guarantee transfer of electricity, to be advised to the *Market Operator* in accordance with *WESM Rules* clause 3.13.2.
Settlement	The activity of producing bills and credit notes for *WESM Members* in accordance with clause 3.13, and with the processes defined in clause 3.14, both of the *WESM Rules*.
Settlement Amount	The amount payable by or to a *trading participant* in respect of a billing period as determined by the *Market Operator* under *WESM Rules* clause 3.13.14.
Settlement Price	An *ex-ante* or *ex-post energy settlement price*.
Settlement Quantity	An *ex-ante* or *ex-post energy settlement quantity*, or a *zonal reserve settlement quantity*.
Settlement Surplus	The *settlement surplus* remaining after all *market transactions* have been accounted for. This remainder is assumed to be attributable to *economic rentals* arising from other binding constraints.
Spot Market	The wholesale electricity spot market (*WESM*).

Terms	**Definition**
Standing Bid / Offer	A standing offer to sell energy or reserve, or a bid to buy energy, submitted by the relevant *trading participant* in accordance with *WESM Rules* clauses 3.5.5, 3.5.6, 3.5.7 or 3.5.8, and revised from time to time in accordance with *WESM Rules* clause 3.5.9, and effective until overridden by submission of a specific *market offer* in accordance with *WESM Rules* clause 3.5.11
State Estimator	A system forming part of the *Energy Management System* of the *System Operator* which determines the status of the power system through system snapshots.
Supplier	Any person or entity licensed by the ERC to sell, broker, market or aggregate electricity to end-users, and registered with the *Market Operator* as a customer under *WESM Rules* clause 2.3.2.
Supply	The sale of electricity by a party other than a generation company or a distribution utility in the franchise area of a distribution utility using the wires of such distribution utility.
System marginal price	The price set by the marginal plant scheduled in any trading period or interval.
System Operator	The party identified as the *System Operator* pursuant to the Philippine Grid Code which is the party responsible for generation dispatch, the provision of ancillary services, and operation and control to ensure safety, power quality, stability, reliability and security of the *grid*.
System Snapshot	The power system status at a certain time and is generated by the state estimator in the Energy Management System of the *System Operator*.

T

Timetable	The timetable prepared by the *Market Operator* for operation of the *spot market* in accordance with *WESM Rules* clause 3.4.2.
Trading Amount	The amount to be paid by, or paid to a *trading participant*, or *Network Service Provider* in respect of *energy, reserve, line rentals,* or *transmission rights* calculated in accordance with *WESM Rules* clauses 3.13.7, 3.13.8, 3.13.9, 3.13.10, or 3.13.14 respectively.
Trading interval	A 1-hour period commencing on the hour.
Trading Participant	A *customer* or *generation company*.
Transmission Constraint Group	*Constraint Violation Coefficient* for the import-export *constraint* between two regions or areas of the power system.
Transmission limits	Generally, thermal limits of individual transmission facilities.
Transmission Line	A power line that is part of a *transmission network*

Terms	Definition
Transmission Loss Factor	Scaling factors applied on the *nodal prices* to account for the network loss associated with the delivery or consumption of energy at different locations in the system.
Transmission Network	A *network* operating at nominal *voltages* of 220 kV and above plus: (a) any part of a *network* operating at nominal *voltages* between 66kV and 220 kV that operates in parallel with and provides support to the higher *voltage transmission network;* (b) any part of a *network* operating at nominal *voltages* between 66 kV and 220 kV that does not operate in parallel with and provide support to the higher *voltage transmission network* but is deemed by the government *to* be part of the *transmission network*.
Transmission System	The *transmission network* together with the connection assets associated with the *transmission network,* which is *connected to* another *transmission* or *distribution system*.
<u>U</u>	
Under generation	*Constraint Violation Coefficient* for the system condition where the demand exceeds the total maximum generation in the system. This also corresponds to system energy balance constraint. This is also known as deficit generation.
<u>V</u>	
Voltage	The electronic force or electric potential between two points that give rise to the flow of electricity.
<u>W</u>	
Week Ahead Dispatch Process	A pre-dispatch process covering the results obtained in the week ahead projections.
WESM Rules	The detailed rules that govern the administration and operation of the *WESM*.