WESM PRICE DETERMINATION METHODOLOGY

Expository Presentation

14 AUGUST 2017

ERC HEARING ROOM

OUTLINE

BACKGROUND

DESIGN ENHANCEMENTS

PDM AMENDMENTS

SUMMARY

BACKGROUND

BACKGROUND

Guiding Principles

- Gross Pool
- Locational Marginal Pricing / Nodal Pricing
- Net Settlement
- Energy and Reserve Co-optimization
- Demand Bidding
- Self commitment
- Rules-based

BACKGROUND
Price Determination Methodology

- Provides the specific details on how the dispatch schedules and locational marginal prices are calculated in the Market Dispatch Optimization Model (MDOM)
  - o Includes price substitution methodology in cases of extreme nodal price separation
  - o Pricing during market intervention and suspension
- Calculation of settlement amounts net of bilateral contracts

BACKGROUND
Milestones

2001
- Electric Power Industry Reform Act (EPIRA) (RA 9136) *(June 2001)*
- Philippine Grid Code *(Dec 2001)*

2002
- EPIRA Implementing Rules and Regulations (IRR) *(Feb 2002)*
- WESM Rules *(June 2002)*

2003
- Philippine Electricity Market Corporation (PEMC) *(Nov 2003)*

2004
- WESM Market Management System (MMS) *(March 2004)*

2006
- Luzon WESM Commercial Operations *(June 2006)*
- Price Det. Methodology *(June 2006)*

2010
- Visayas WESM Commercial Operations *(Dec 2010)*

2013
- Retail Competition and Open Access *(June 2013)*

2015
- Central Scheduling of Energy and Reserves *(Dec 2015)*

2016
- Integration of Preferential Dispatch RE Resources *(Jan 2016)*
- Enhanced WESM Design Amendments *(Oct 2016)*

2017
- Enhanced WESM Design TOP *(June 2017)*
- WESM Mindanao Launch *(June 2017)*
- Enhanced WESM Design Commercial Operations

WESM DESIGN ENHANCEMENTS

WESM DESIGN ENHANCEMENTS
Purpose

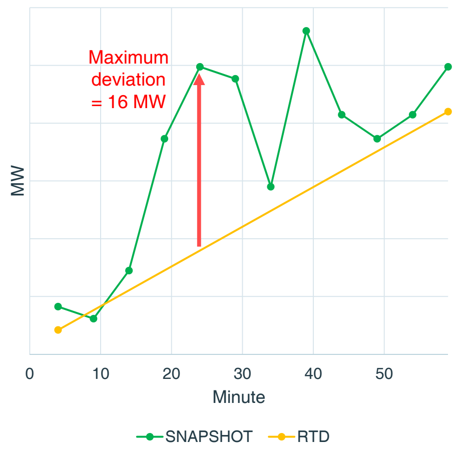
Issue	Enhancement
Large intra-hour dispatch deviation	Reduce dispatch interval to 5 minutes from 1 hour
	Ex-ante pricing only
Non-availability of settlement-ready prices in near real-time	Automatic pricing re-run Timely provision of other prices
Mandatory dispatching of generators at their Pmin level	Economic scheduling of Pmin

Enhancements are consistent with Guiding Principles, and target market efficiency and transparency

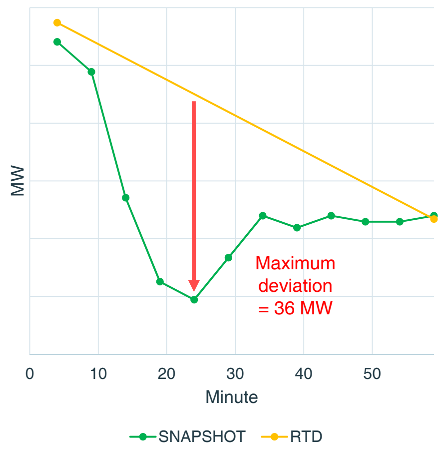
WESM DESIGN ENHANCEMENTS

Large Intra-Hour Dispatch Deviation

Sample Upwards Deviation



Sample Downwards Deviation



WESM DESIGN ENHANCEMENTS

Non-availability of settlement-ready prices in near real-time

RTD

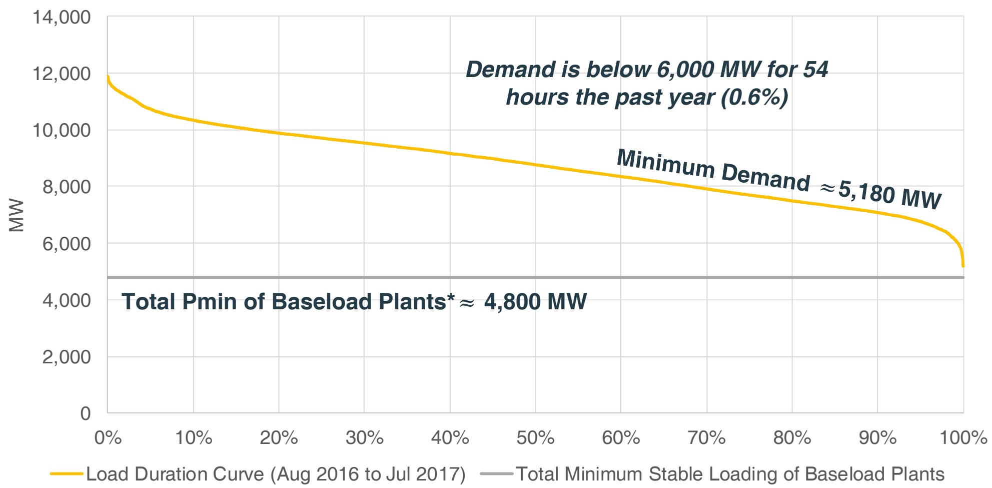
	LUZON					VISAYAS				
Year	OK	PEN	PSM	SEC	AP	OK	PEN	PSM	SEC	AP
2011	53%	41%	5%	0%	0%	75%	20%	5%	0%	0%
2012	52%	45%	3%	0%	0%	89%	7%	3%	0%	0%
2013	54%	40%	6%	0%	0%	81%	3%	3%	0%	13%
2014	49%	33%	12%	2%	3%	59%	4%	9%	2%	25%
2015	54%	38%	8%	0%	0%	84%	8%	8%	0%	0%
2016	50%	32%	18%	0%	1%	75%	6%	18%	0%	0%
2017	62%	16%	21%	0%	0%	72%	3%	25%	0%	0%

RTX

	LUZON					VISAYAS				
Year	OK	PEN	PSM	SEC	AP	OK	PEN	PSM	SEC	AP
2011	95%	4%	0%	0%	0%	96%	3%	0%	0%	0%
2012	93%	6%	1%	0%	0%	93%	6%	1%	0%	0%
2013	93%	7%	0%	0%	0%	84%	3%	0%	0%	13%
2014	88%	5%	1%	2%	3%	67%	3%	2%	2%	25%
2015	93%	4%	3%	0%	0%	92%	5%	3%	0%	0%
2016	76%	6%	17%	0%	1%	77%	5%	18%	0%	0%
2017	79%	2%	19%	0%	0%	74%	2%	24%	0%	0%

WESM DESIGN ENHANCEMENTS

Economic scheduling of Pmin



*Baseload plants: biomass, coal, geothermal, and natural gas

WESM DESIGN ENHANCEMENTS

Developments

2013: Market Study conducted by IES

- 19 public consultations

2014: Market Study submitted to DOE

2015: DOE Department Circular No. DC2015-10-0015

- Established the guiding principles for the WESM design enhancements
- Mandated amendments to the WESM Rules through the rules change process

2016: DOE Department Circular No. DC2016-10-0014

- Approved amendments to the WESM Rules

2017: DOE Department Circular No. DC2017-03-0001

- Approved amendments to the Price Determination Methodology and Constraints Violation Coefficients and Pricing Re-runs Manual

PDM AMENDMENTS

REVISED PDM MANUAL STRUCTURE

Contents

PDM (2006)

- Market Dispatch Optimization Model
- Billing and Settlement

Other pricing & settlement manuals:

- APDM ('06)
- MRU ('08)
- PSM ('09)
- NSS ('09)
- PCRM (Not approved yet)

Enhancements

***Revised* PDM**

- Market Dispatch Optimization Model
- ***Market Re-run***
- ***PSM***
- ***APDM***
- ***NSS***
- ***PCRM***
- ***Billing and Settlement***

SUMMARY OF ENHANCEMENTS TO THE PDM

- Market Dispatch Optimization Model
- Automatic Pricing Re-runs
- Price Substitution Methodology
- Administered Price Determination Methodology
- Treatment of Must-Run Units
- Settlement Calculations (Energy, Reserves, NSS)

*NSS – net settlement surplus

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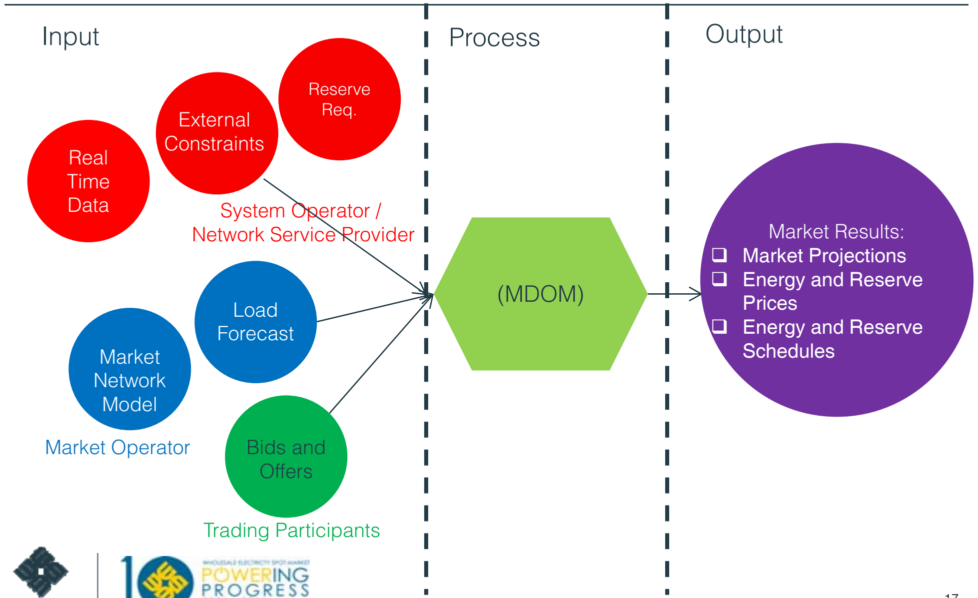
MARKET DISPATCH OPTIMIZATION MODEL (MDOM)

Overview



MDOM

Projections and Real-Time Dispatch (RTD) Timetable

Week-Ahead Projections (once a day)

Hourly projections

D	D+1	D+2	D+3	D+4	D+5	D+6	D+7

Day-Ahead Projections (hourly)

Before 1200H

Hourly projections

D	D+1

1200H onwards

Hourly projections

D	D+1

Hour-Ahead Projections (every five minutes)

Per dispatch interval projections

DI	DI+5m	DI+10m	DI+15m	…	DI+50m	DI+55m	DI+60m

Real-Time Dispatch (every five minutes)

Per dispatch interval scheduling and pricing

DI

MDOM

General Formulation

Objective

- *Maximize the value of dispatched load*
- While *minimizing cost* of dispatched generation, dispatched reserves, and constraint violations

Subject to

- Energy and reserve requirements
- Transmission system capabilities
- Individual technical capabilities of resources

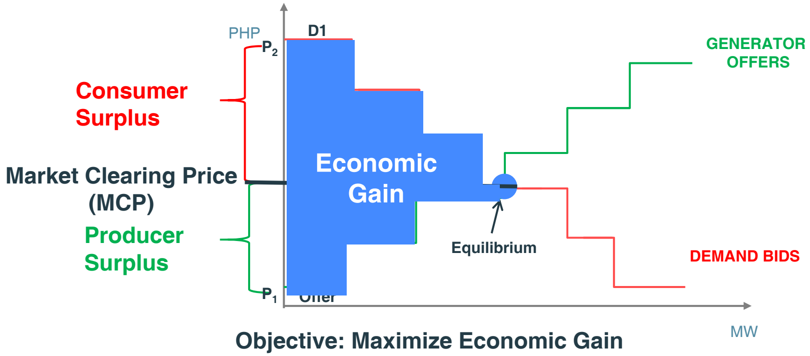
MDOM

Detailed Formulation of the Objective Function

WESM Rules Clause 3.6.1.3	Current	New
Maximize **value of dispatched load** based on dispatch bids, minus	$\left\{\sum_{i}^{E_D} \sum_{j}\left[(DB_{i,j})(PDB_{i,j})\right]\right.$	$\sum_{i}^{n}\left\{\sum_{b}^{E_D}\left[(DB_{b,i})(PDB_{b,i})\right]\right.$
Cost of dispatched generation based on dispatched offers	$-\sum_{i}^{E_G} \sum_{j}\left[(G_{i,j})(PG_{i,j})\right]$	$-\sum_{k}^{E_G}\left[(G_{k,i})(PG_{k,i})\right]$
Cost of dispatched reserves based on reserves contracted for or when applicable reserve offers	$-\sum_{i}^{E_R} \sum_{k}^{N_K} \sum_{j}\left[(R_{i,j,k})(PR_{i,j,k})\right]$	$-\sum_{r}^{N_R} \sum_{j}^{E_R}\left[(R_{j,r,i})(PR_{j,r,i})\right]$
Cost of constraint violation based on the constraint violation coefficients.	$\left.-(CVP)\right\}$	$\left.-\sum_{c}^{E_C}\left[(CQ_{c,i})(CP_{c,i})\right]-\sum CVP\right\}$ **Curtailment price can be set per node**
Subscripts	i – resource j – offer block k – reserve type	i – dispatch interval b – demand bid block k – generation offer block j – reserve offer block r – reserve category c – curtailment quantity

MDOM

Objective Function



Objective: Maximize Economic Gain

MDOM

Detailed Constraints

a. System Constraints

i. System power balance
ii. Reserve region requirements
iii. Reserve provider capacity cap
iv. AC power flow, including the network loss model and power flow limits
v. HVDC flow limit
vi. Nodal energy balance constraint

b. Generic Constraints

i. Over-riding Constraints
   - Security Limit
   - Transmission Limit

ii. Outage schedule
iii. Contingency list

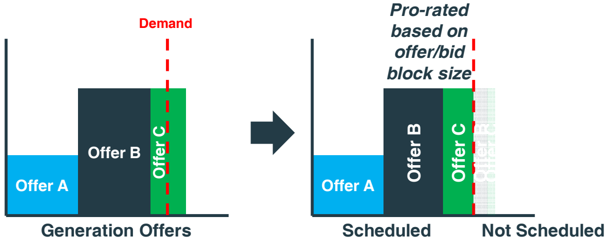
c. Resource Constraints

i. Generator resource energy constraint
ii. Load resource energy constraint
iii. Reserve resource constraint
iv. Combined energy and reserve capacity limit
v. Combined energy and reserve ramping
vi. Constraints that pertain to the operational modes of generators, loads or similar facilities (e.g., battery energy storage systems, pump storage hydro)

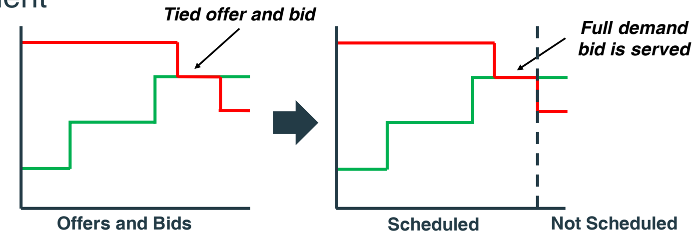
MDOM

Tie-breaking of Equivalent Offers

- Pro-rate the schedule based on offer/bid block



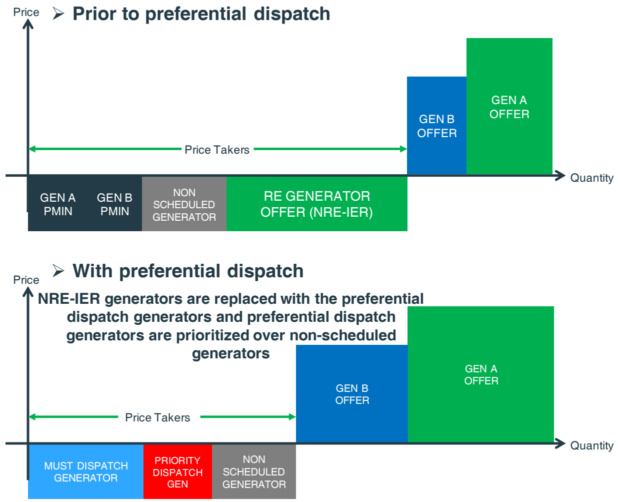
- In case of a tie between a demand bid and a generator offer, the generation offer shall be maximized to meet the load requirement



MDOM

Priority-scheduling

- When restricting dispatch schedules, following hierarchy shall be followed:
  - Market offers of scheduled generating units;
  - Non-scheduled generating units[1];
  - Priority dispatch generating units[2]; and
  - Must dispatch generating units[3].



1\ Plants with capacity less than 0.1% of regional peak demand
2\ FIT-qualified biomass plants
3\ Solar, wind, run-of-river hydro plants

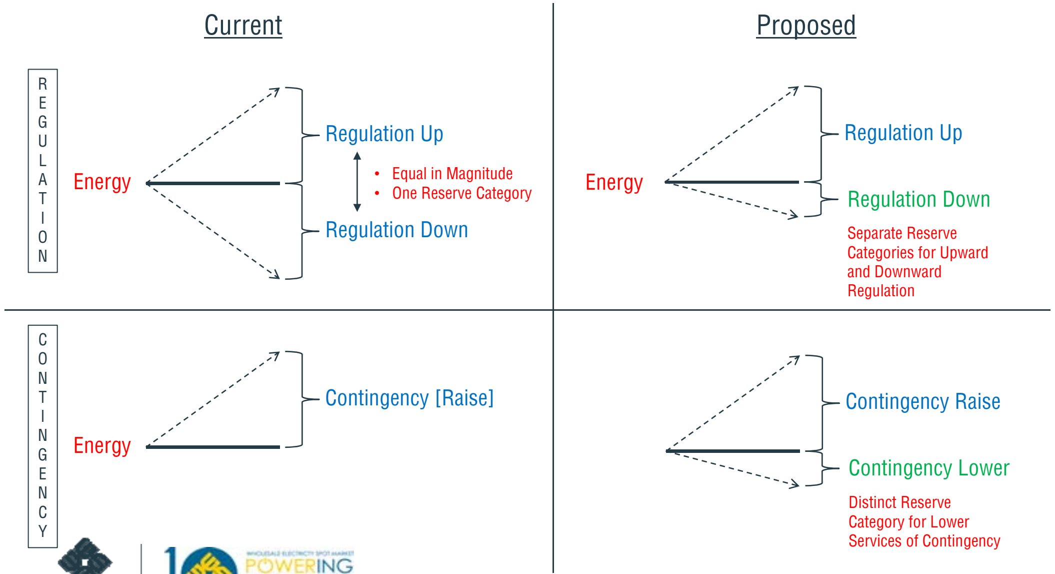
MDOM

Reserves

- Categories
  - o Regulation (Secondary) - Raise/Lower
  - o Contingency (Primary & Tertiary) - Raise/Lower
- Reserve Regions
  - o Luzon
  - o Visayas
  - o Mindanao

RESERVES

Reserve Categories [Distinction between Raise and Lower Reserves]



SUMMARY OF ENHANCEMENTS TO THE PDM

- Market Dispatch Optimization Model
- Automatic Pricing Re-runs
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*NSS – net settlement surplus

MARKET PRICING RE-RUNS

Overview

- Prices reflecting constraint violation penalties are not settled, and are re-run
- In the current system, high level of PENs issued, and settlement ready prices are ready only at the end of the billing month
- Automatic re-run of prices enable availability of settlement ready prices near real time

MARKET PRICING RE-RUNS
Timeline

Current

Run RTD → In real-time: Publish price with CVCs in MPI → Prior to preliminary bill issuance (7 days after end of billing month): Perform Manual Re-Run → 18 days after end of billing month: *Issue Final Prices with Final Bills*

New Process

Run RTD
- Scheduling run
- Pricing run

→ In real-time: *Publish Final Prices in MPI*

List of constraints violated are published in the website the day after

MARKET PRICING RE-RUNS
How is it done?

- The **automatic pricing re-run of the MDOM** shall determine the prices for energy and reserves with **relaxed constraints** and shall have approximately the same dispatch schedules.
- Shortage and Excess Pricing
  - For under-generation, the shortage price shall be determined as the offer price cap.
  - For over-generation, the excess price shall be determined as the offer price floor.

o Manual re-runs done only for errors due to erroneous input data

MARKET PRICING RE-RUNS
Constraint Violation Coefficients

Order	Constraint Violation Coefficient Name	CVC
1	Delayed Contingency Reserve Requirement	100,000
2	Slow Contingency Reserve Requirement	200,000
3	Fast Contingency Reserve Requirement	400,000
4	Nodal Value of Lost Load or Nodal Energy Balance Constraint	800,000
5	System Energy Balance Constraint	1,300,000
6	Self-Scheduled Generation Constraint	1,400,000
7	Thermal Contingency Constraint	2,400,000
8	Regulating Reserve Requirement	2,800,000
9	Transmission Group Constraint	2,900,000
10	Thermal Base Case Constraint	3,000,000

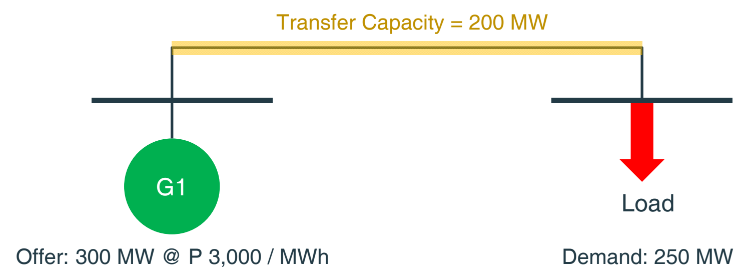
Lowest Priority in Meeting Requirement

↓

Highest Priority in Meeting Requirement

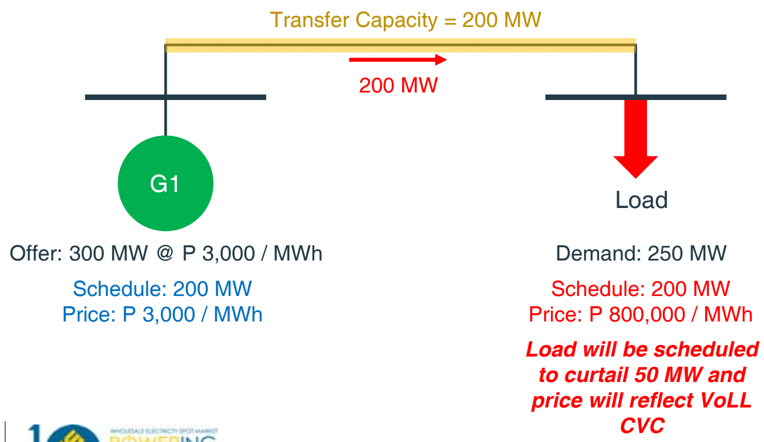
MARKET PRICING RE-RUNS

Scheduling Run → Pricing Run



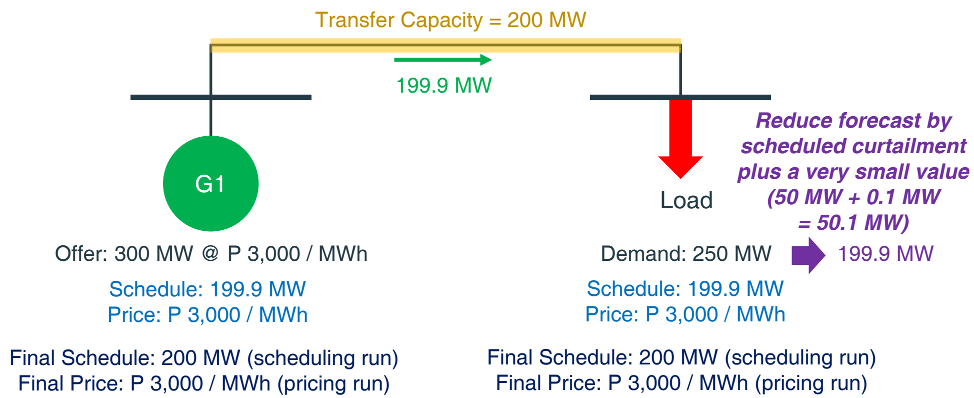
MARKET PRICING RE-RUNS

Scheduling Run → Pricing Run



MARKET PRICING RE-RUNS

Scheduling Run → Pricing Run



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PRICE SUBSTITUTION METHODOLOGY (PSM)

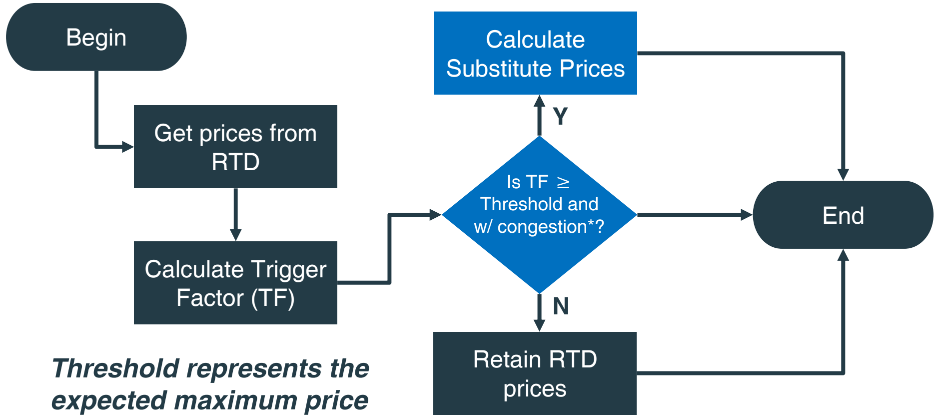
Overview

- This methodology addresses **occurrence of extreme nodal price separation** arising from **the effects of network congestion** in the power system
- If a dispatch interval is reflective of extreme nodal price separation due to network congestion, then prices shall be substituted for the affected generators and customers.
- Proposed PSM uses the same principles as the original, but ensures that there are settlement ready prices available near real time

PRICE SUBSTITUTION METHODOLOGY (PSM)

Overview

- When is PSM applied?

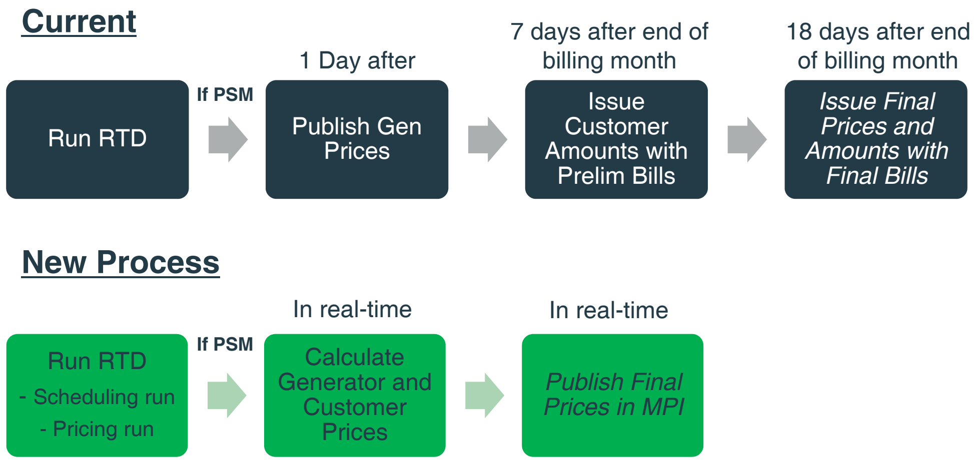


Threshold represents the expected maximum price spread from losses

*PSM will only be triggered if there is congestion on network lines with loop flows

PRICE SUBSTITUTION METHODOLOGY (PSM)

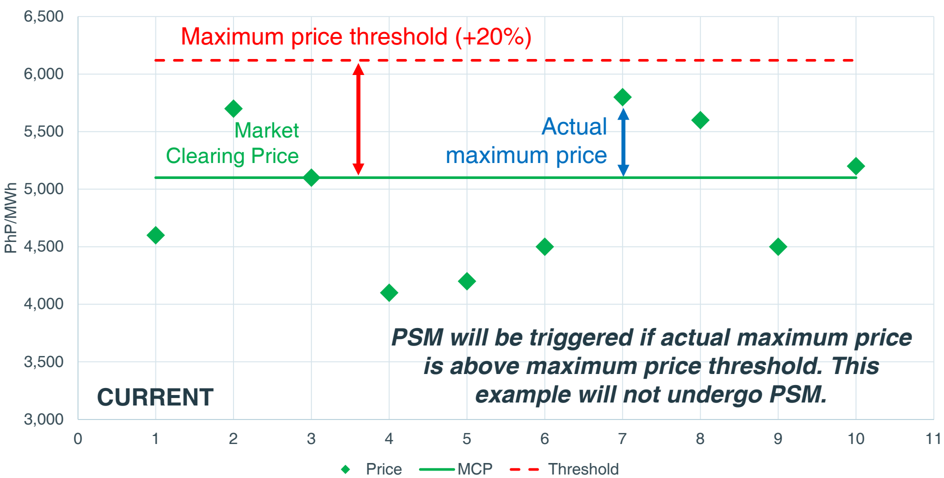
Timeline



PRICE SUBSTITUTION METHODOLOGY

Trigger Factor

Current Implementation	Proposed Changes	Rationale
Trigger factor formulation based on highest market clearing price (MCP).	Trigger factor formulation based on weighted average price of all resources	Consider integration of reserves and cover special cases



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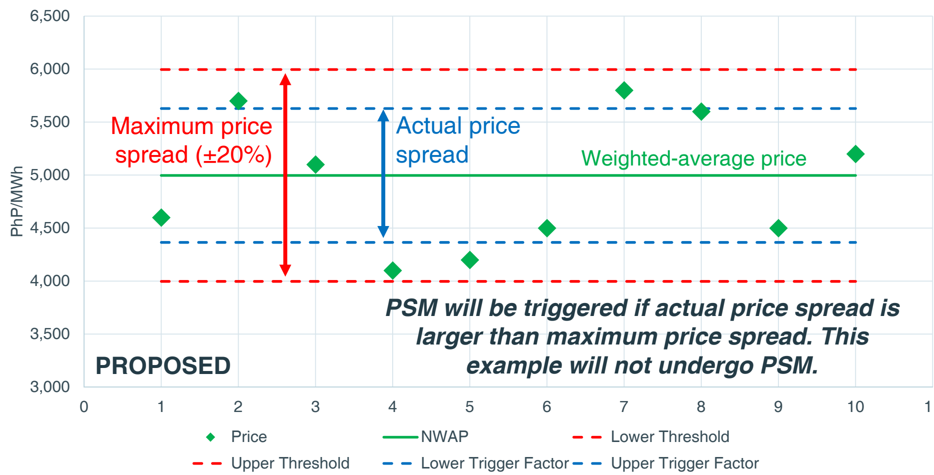
Trigger factor formulation based on highest market clearing price (MCP).	Trigger factor formulation based on weighted average price of all resources	Consider integration of reserves and cover special cases

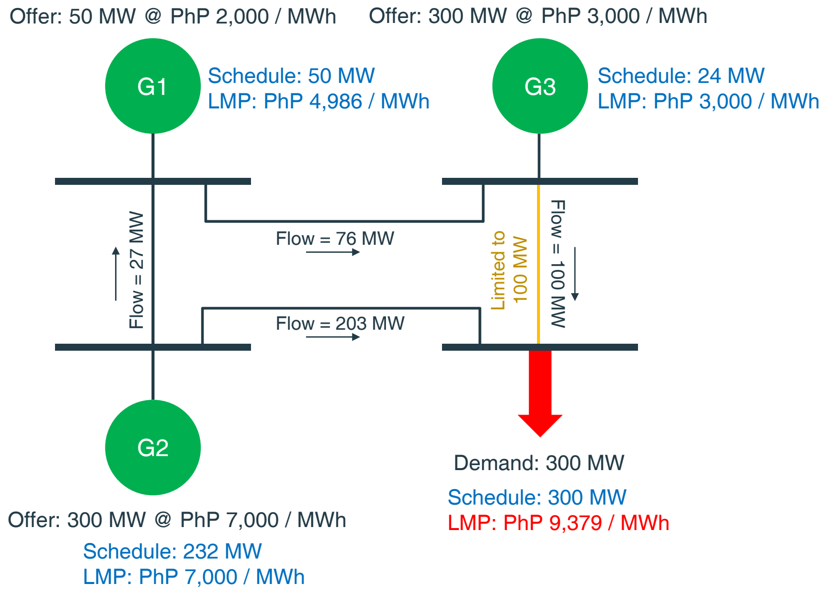


PRICE SUBSTITUTION METHODOLOGY (PSM)

Current Implementation	Proposed Changes	Rationale
Constrained-On Generators – Pay as Bid Not Constrained-On Generators – Unconstrained Market Clearing Price	NONE	To produce market prices immediately after the dispatch interval. Also, consistent with the reduction of dispatch intervals to 5-minutes and ex-ante only pricing.
Generator settlement amounts are allocated to loads based on MQ and BCQ during prelim and final settlement	Single load price is computed in real-time based on the allocation of the total generation cost based on schedule	

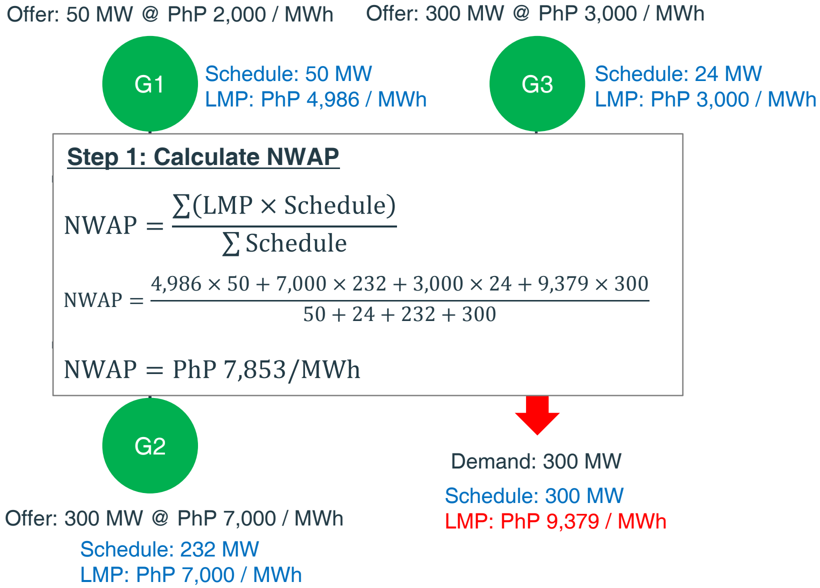
PRICE SUBSTITUTION METHODOLOGY (PSM)

Example



PRICE SUBSTITUTION METHODOLOGY (PSM)

Example



Step 1: Calculate NWAP

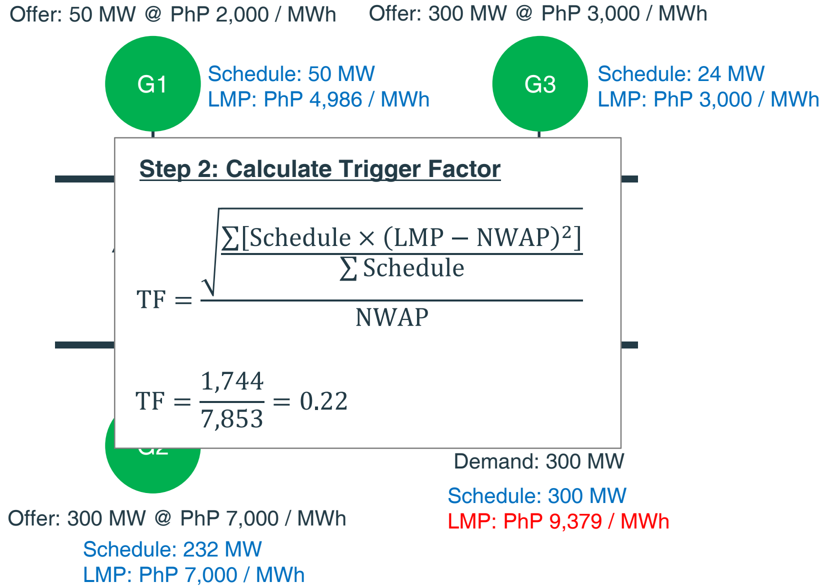
$$\text{NWAP} = \frac{\sum(\text{LMP} \times \text{Schedule})}{\sum \text{Schedule}}$$

$$\text{NWAP} = \frac{4{,}986 \times 50 + 7{,}000 \times 232 + 3{,}000 \times 24 + 9{,}379 \times 300}{50 + 24 + 232 + 300}$$

$$\text{NWAP} = \text{PhP } 7{,}853/\text{MWh}$$

PRICE SUBSTITUTION METHODOLOGY (PSM)

Example



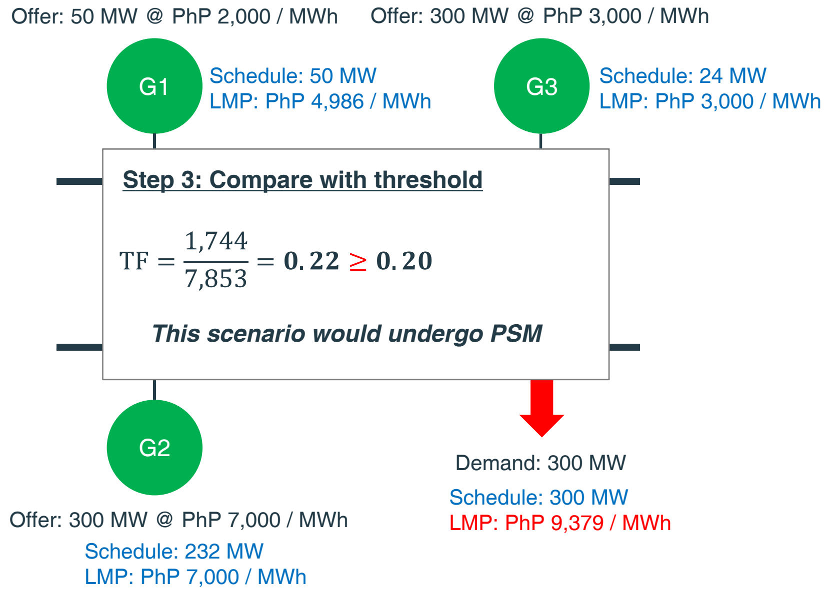
Step 2: Calculate Trigger Factor

$$\text{TF} = \frac{\sqrt{\dfrac{\sum[\text{Schedule} \times (\text{LMP} - \text{NWAP})^2]}{\sum \text{Schedule}}}}{\text{NWAP}}$$

$$\text{TF} = \frac{1{,}744}{7{,}853} = 0.22$$

PRICE SUBSTITUTION METHODOLOGY (PSM)

Example



PRICE SUBSTITUTION METHODOLOGY (PSM)

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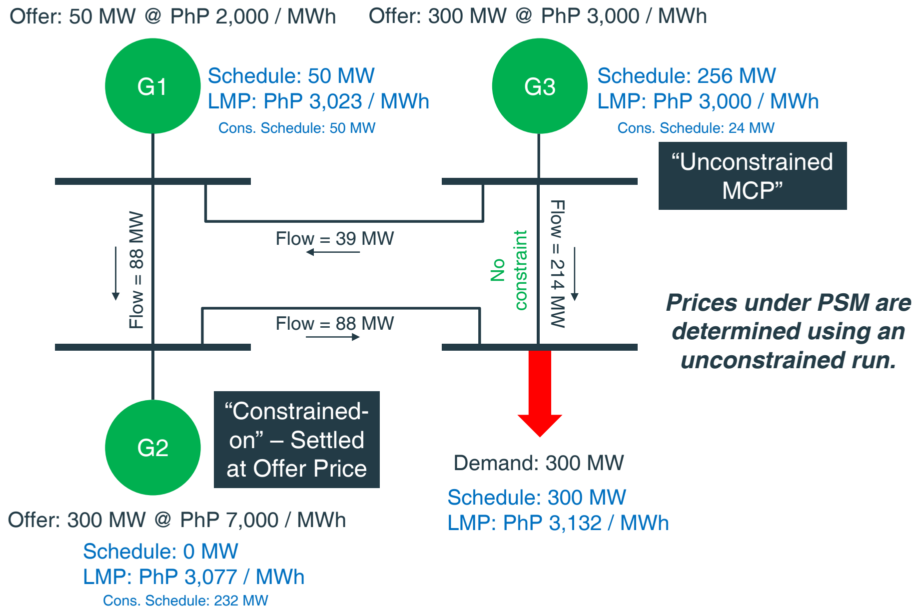


PRICE SUBSTITUTION METHODOLOGY (PSM)

Example

Part	Schedule (MW)	Substitute Energy Dispatch Price (PhP / MWh)
G1 (Unconstrained)	50	3,000
G2 (Constrained-on)	232	7,000
G3 (Unconstrained)	24	3,000
Load	300	?

$$\text{Load SEDP} = \frac{\sum(\text{SEDP}_{\text{Gen}} \times \text{Schedule}_{\text{Gen}})}{\sum \text{Schedule}_{\text{Load}}}$$

$$\text{Load SEDP} = \frac{50 \times 3{,}000 + 232 \times 7{,}000 + 24 \times 3{,}000}{300}$$

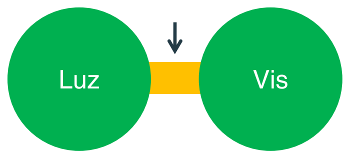
$$\textbf{Load SEDP} = \textbf{PhP 6,153/MWh}$$

PRICE SUBSTITUTION METHODOLOGY (PSM)

Regional Application

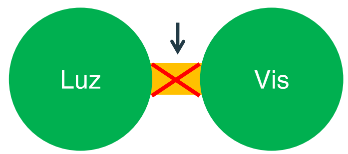
Current Design

Regional if HVDC Sched is Binding (at the limit)



New Design

Regional if HVDC is scheduled at zero



SUMMARY OF ENHANCEMENTS TO THE PDM

- Market Dispatch Optimization Model
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- Price Substitution Methodology
- **Administered Price Determination Methodology**
- Treatment of Must-Run Units
- Settlement Calculations (Energy, Reserves, NSS)

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ADMINISTERED PRICE (AP)

Overview

- Administered prices are used when market intervention or market suspension is declared
- Proposed methodology uses the same principles as the current but allows AP prices to be available near real-time
- Further adjustments to the methodology were made on imports from regions, when one region is not under market intervention or suspension

ADMINISTERED PRICE (AP)

Timeline

Current

Run RTD → If AP → Compute Generator Prices (7 days after end of billing month) → Issue Customer Amounts with Prelim Bills (7 days after end of billing month) → *Issue Final Prices and Amounts with Final Bills* (18 days after end of billing month)

New Process

Run RTD
- Scheduling run
- Pricing run

→ If AP → Calculate Generator and Customer Prices (In real-time) → *Publish Final Prices in MPI* (In real-time)

ADMINISTERED PRICE (AP)

Generator Administered Price

Current Implementation	Proposed Changes	Rationale
Generation energy AP is computed based on ex-post price and metered quantity.	Generation energy AP is computed based on nodal energy dispatch prices and schedules.	Timely provision of administered prices.

	S	M	T	
W-4			H09	EPP_{W-4} x MQ_{W-4}
W-3			H09	EPP_{W-3} x MQ_{W-3}
W-2			H09	EPP_{W-2} x MQ_{W-2}
W-1			H09	EPP_{W-1} x MQ_{W-1}
W			H09	

Change to Final Energy Dispatch Price (FEDP)

Change to Snapshot Quantity (SQ)

$$\frac{\sum(\text{FEDP} \times \text{SQ})}{\sum \text{SQ}} = \textbf{Administered Price}_W$$

Weighted-Average

ADMINISTERED PRICE (AP)

Generator Administered Price - Example

W	FEDP (PhP/MWh)	SQ (MW)	FEDP × SQ
W-4	5,670	15	85,050
W-3	4,438	13	57,694
W-2	4,149	11	45,639
W-1	4,140	15	62,100
TOT	--	**54**	**250,483**

$$\textbf{Administered Price}_W = \frac{\sum(\text{FEDP x SQ})}{\sum \text{SQ}}$$

$$\frac{250{,}483}{54}$$

Administered Price$_W$ = PhP 4,639 / MWh

ADMINISTERED PRICE (AP)

Customer Administered Price

Current Implementation	Proposed Changes	Rationale
Customer settlement amounts are based on the allocation of total generation payments	Customer prices are computed based on the allocation of the total generation cost based on snapshot	Timely provision of administered prices.

$$\text{Settlement Amount}_{\text{Load}} = \underbrace{\boxed{\left(\frac{\sum \text{AP}_{\text{Gen}} \times \text{MQ}_{\text{Gen}}}{\text{Total MQ}_{\text{Load}}}\right)}}_{\textbf{AP}_{\textbf{Load}}} \times \text{MQ}_{\text{Load}}$$

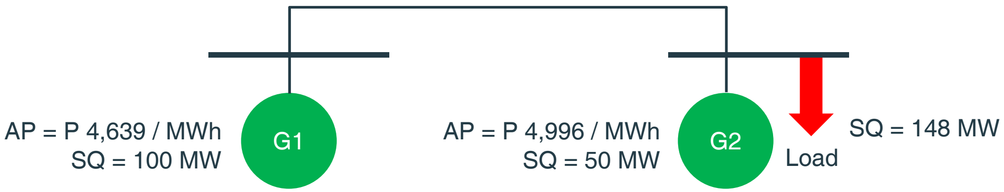
$$\text{Administered Price}_{\text{Load}} = \frac{\sum(\text{AP}_{\text{Gen}} \times \text{MQ}_{\text{Gen}})}{\text{Total MQ}_{\text{Load}}}$$

Change to Snapshot Quantity (SQ) of Generators

Change to Snapshot Quantity (SQ) of Loads

ADMINISTERED PRICE (AP)

Customer Administered Price - Example



$$\text{Administered Price}_{\text{Load}} = \frac{\sum(\text{AP}_{\text{Gen}} \times \text{SQ}_{\text{Gen}})}{\text{Total SQ}_{\text{Load}}}$$

$$\text{Administered Price}_{\text{Load}} = \frac{4{,}639 \times 100 + 4{,}996 \times 50}{148}$$

$$\text{Administered Price}_{\text{Load}} = \text{PhP } 4{,}822/\text{MWh}$$

ADMINISTERED PRICE (AP)

Other features

Current Implementation	Proposed Changes	Rationale
NEW	Added formula for determining AP when node is newly modelled based on GWAP of other generators.	In compliance with the ERC's direction during the APDM hearing
NEW	AP for reserves based on the schedule weighted average of the reserve prices for each reserve category of the 4 most recent similar trading day and similar dispatch intervals that have not been administered.	To consider the integration of reserves into the WESM, wherein market results are based from and reflect a co-optimized solution.

ADMINISTERED PRICE (AP)

Regional Application

- The administered price shall be applied in the region where the market suspension or market intervention is declared. For this purpose, the regions are Luzon, Visayas and Mindanao.
- If there is an interconnection, the actual flow in the interconnection shall be considered in the customer allocation.

ADMINISTERED PRICE (AP)

Regional Application

Current Implementation	Proposed Changes	Rationale
Determination of import and export amounts use EPP and MQ Determination of adjustment to non-administered region use EPP and MQ	Use GWAP of non-administered region (instead of EPP) and snapshot of HVDC flow (instead of MQ)	Generalize reference price in non-administered region

Change to Snapshot Quantity (SQ) of Generators

Change to GWAP of non-administered region or GWAEAP

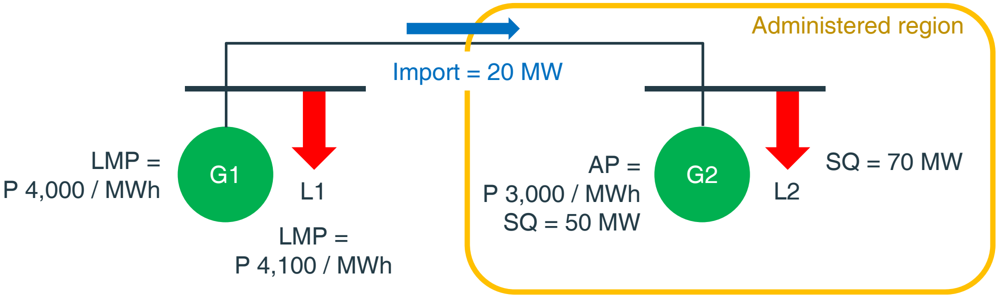
$$\text{Administered Price}_{\text{Load}} = \frac{\sum(\text{AP}_{\text{Gen}} \times \text{MQ}_{\text{Gen}}) \pm (\text{EPP}_{\text{NAR}} \times \text{MQ}_{\text{HVDC}})}{\text{Total MQ}_{\text{Load}}}$$

Change to Snapshot Quantity (SQ) of Loads

Change to snapshot quantity (SQ) of interconnection

ADMINISTERED PRICE (AP)

Customer Administered Price with Import - Example



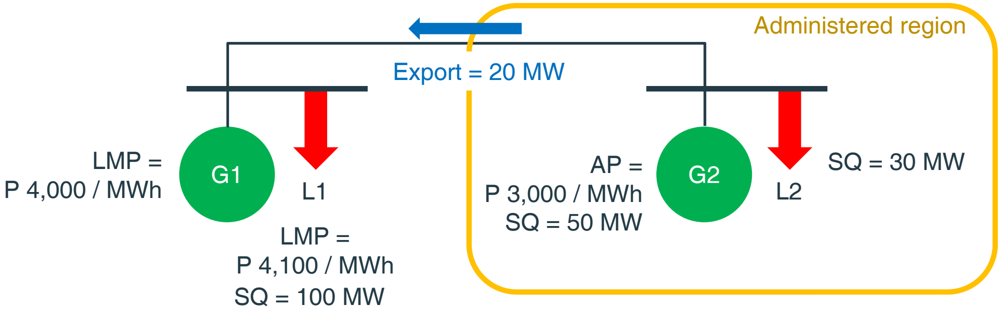
$$\text{Administered Price}_{\text{Load}} = \frac{\sum(\text{AP}_{\text{Gen}} \times \text{SQ}_{\text{Gen}}) + (\text{GWAP}_{\text{NAR}} \times \text{SQ}_{\text{HVDC}})}{\text{Total SQ}_{\text{Load}}}$$

$$\text{Administered Price}_{\text{Load}} = \frac{(3{,}000 \times 50) + (4{,}000 \times 20)}{70}$$

$$\text{Administered Price}_{\text{Load}} = \text{PhP } 3{,}296/\text{MWh}$$

ADMINISTERED PRICE (AP)

Customer Administered Price with Export - Example



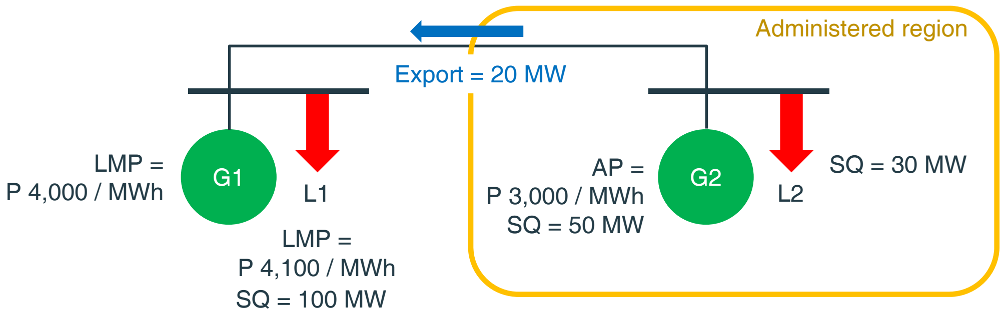
$$\text{Administered Price}_{\text{Load}} = \frac{\sum(\text{AP}_{\text{Gen}} \times \text{SQ}_{\text{Gen}}) - (\text{GWAEAP} \times \text{SQ}_{\text{HVDC}})}{\text{Total SQ}_{\text{Load}}}$$

$$\text{Administered Price}_{\text{Load}} = \frac{(3{,}000 \times 50) - (3{,}000 \times 20)}{30}$$

$$\text{Administered Price}_{\text{Load}} = \text{PhP } 3{,}000/\text{MWh}$$

ADMINISTERED PRICE (AP)

Customer Administered Price with Export - Example



$$\text{Non}-\text{Administered Region Administered Price Adjustment(NARAPA)} = \frac{SQ_{HVDC} \times (GWAEAP - GWAP_{NAR})}{\text{Total } SQ_{NAR-Load}}$$

$$NARAPA = \frac{20 \times (3{,}000 - 4{,}000)}{100} \qquad NARAPA = -PhP\ 200/MWh$$

$$\text{Final L1 Price} = 4{,}100 - 200 = PhP\ 3{,}900\ /MWh$$

SUMMARY OF ENHANCEMENTS TO THE PDM

- Market Dispatch Optimization Model
- Automatic Pricing Re-runs
- Price Substitution Methodology
- Administered Price Determination Methodology
- Treatment of Must-Run Units
- Settlement Calculations (Energy, Reserves, NSS)

*NSS – net settlement surplus

MUST-RUN UNITS

Overview

- Used address a threat in system security when all available ancillary services have been exhausted
- Criteria:
  - o System Voltage Requirement
  - o Thermal Limits
  - o Real Power Balancing and Frequency Control
- Change in methodology driven by the need to produce settlement ready prices near real-time.

MUST-RUN UNITS

Compensation

Current Implementation	Proposed Changes	Rationale
Generation price index (GPI)* + If necessary, additional compensation** to cover variable costs	Market price (price taker) + If necessary, additional compensation** to cover variable costs	Timely provision of prices.

$$* \quad GPI_{h,m} = \frac{\sum_{d=1}^{n} Payment_{bilateral,h,d,m-1} + \sum_{d=1}^{n} Payment_{Spot,h,d,m-1}}{\sum_{d=1}^{n} Quantity_{metered,h,d,m-1}}$$

Based on NPC-TOU rates

** Recent changes allow constrain-on plants to apply for additional compensation

SUMMARY OF ENHANCEMENTS TO THE PDM

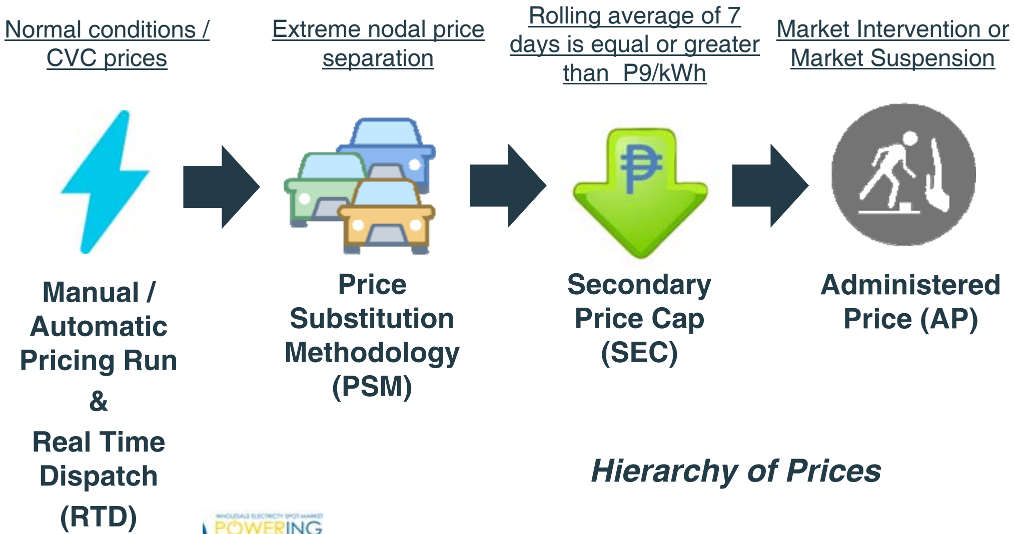
- Market Dispatch Optimization Model
- Automatic Pricing Re-runs
- Price Substitution Methodology
- Administered Price Determination Methodology
- Treatment of Must-Run Units
- Settlement Calculations (Energy, Reserves, NSS)

*NSS – net settlement surplus

SETTLEMENT CALCULATIONS
Overview

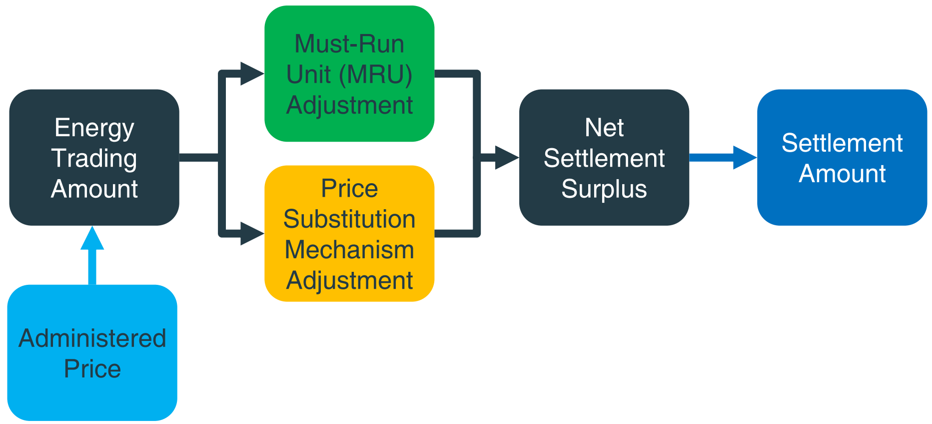
- Changes in the settlement calculations are driven by shortening of dispatch interval and ex ante only pricing, and the amendments to the pricing methodologies
- Resulting amendment provides for settlement calculations that are simplified and uniform
- Reserve cost recovery is included in the PDM

SETTLEMENT CALCULATIONS
Final Energy Dispatch Price (FEDP)

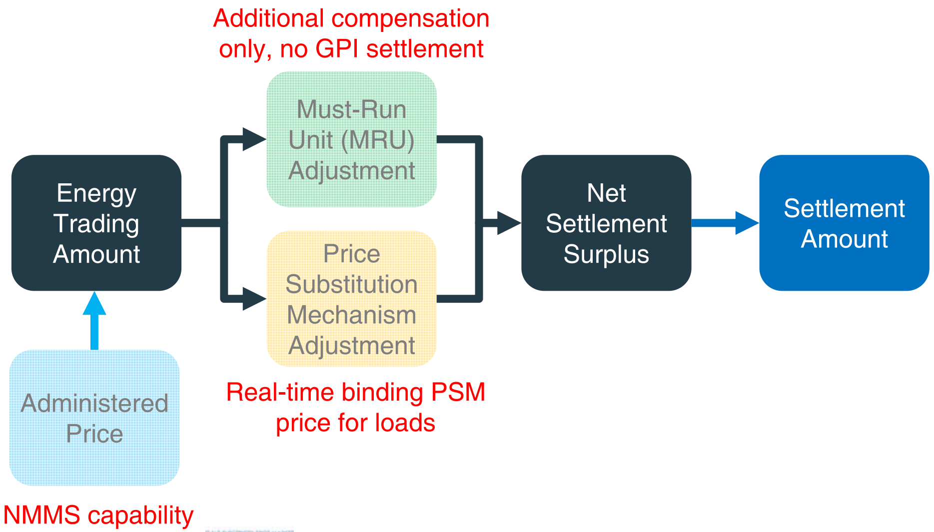


Hierarchy of Prices

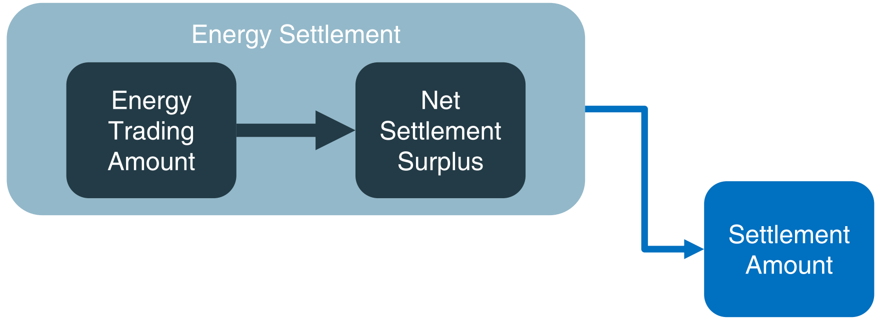
SETTLEMENT CALCULATIONS
Current



SETTLEMENT CALCULATIONS
Enhanced



SETTLEMENT CALCULATIONS
Enhanced



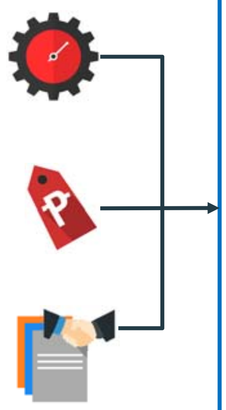
SETTLEMENT CALCULATIONS
Enhanced – Energy Trading Amount

Settlement Inputs

Metered Quantities (MQ)

Final Energy Dispatch Price (FEDP)

Bilateral Contract Quantities (BCQ)



Per dispatch interval (5-minutes),

Energy Trading Amount =

$$MQ \times FEDP - BCQ \times FEDP_{@RefNode}$$

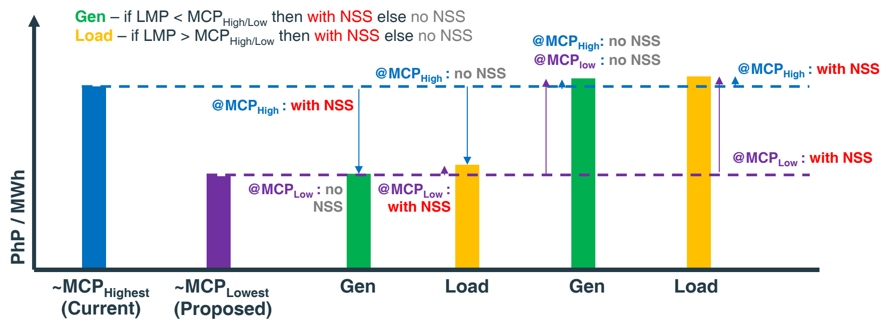
SETTLEMENT CALCULATIONS
Enhanced – Energy Trading Amount (Example)

PART	MQ [A]	BCQ [B]	FEDP [C]	FEDP@RefNode [D]	ETA [A×C – B×D]
G1	252	150	3,000	3,000	**306,300**
G2	103	50	5,000	5,102	**259,924**
L1	(150)	(150)	3,046	3,000	**(6,827)**
L2	(200)	(50)	5,102	5,102	**(765,230)**
				NET	**(205,833)**

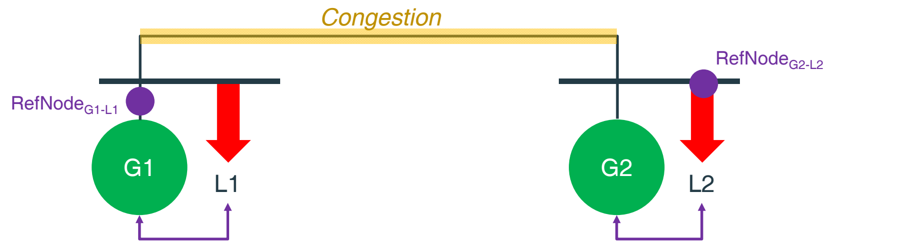
Net Settlement Surplus

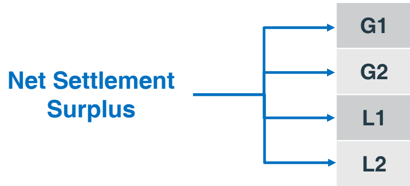
SETTLEMENT CALCULATIONS
Enhanced – Net Settlement Surplus

Parameter	Current	Proposed
Line Loss and Congestion Cost	Estimated based on LMP and MCP	Based on actual marginal loss and congestion cost
Cost of Line Loss and Congestion associated with Bilateral Contracts	Accounted to generator	Accounted to actual payer based on contract delivery point
Generator	Receives NSS if payment is less than the higher clearing price	Receives NSS if payment is less than the lower clearing price
Load	Receives NSS if payment is more than the higher clearing price	Receives full NSS if payment is more than the lower clearing price



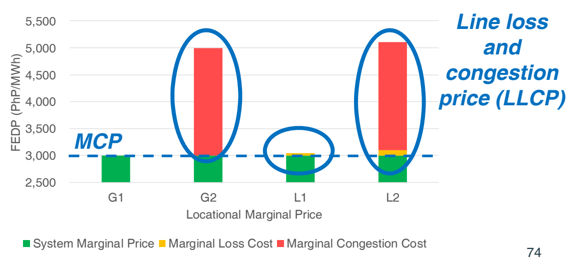
SETTLEMENT CALCULATIONS
Enhanced – Net Settlement Surplus



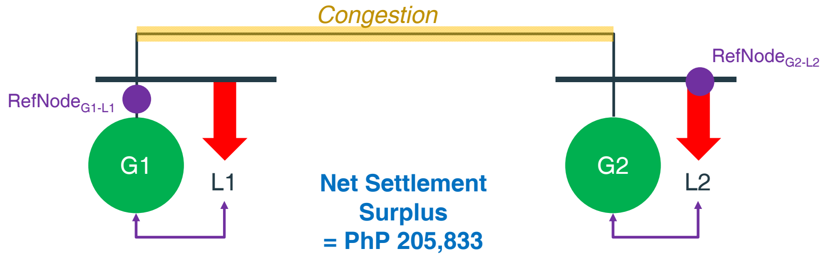


Allocate based on line loss and congestion cost (LLCC) payments

$LLCC = MQ \times LLCP - BCQ \times LLCP_{@RefNode}$



SETTLEMENT CALCULATIONS
Enhanced – Net Settlement Surplus (Example)



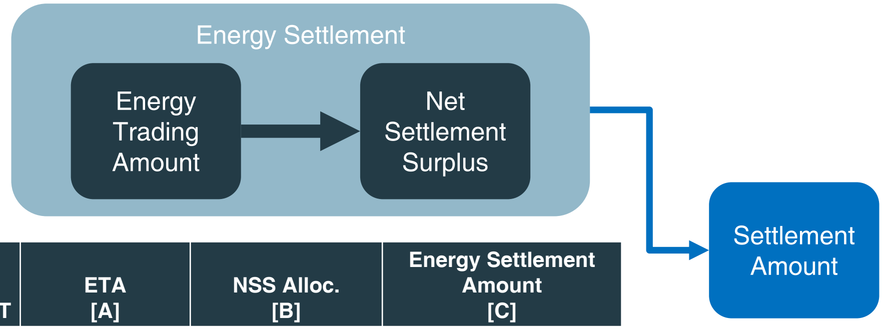
Net Settlement Surplus = PhP 205,833

PART	MQ [A]	BCQ [B]	LLCP [C]	LLCP@RefNode [D]	LLCC* [E=A×C – B×D]	NSS Alloc. [NSS×E/TOTAL E]
G1	252	150	0	0	0	**0**
G2	103	50	2,000	2,102	0	**0**
L1	(150)	(150)	46	0	(6,827)	**4,363**
L2	(200)	(50)	2,102	2,102	(315,230)	**201,470**
	5	0			(322,056)	**205,833**

NSS is allocated to participants with actual payments for congestion

*Only payments are considered (negative value)

SETTLEMENT CALCULATIONS
Enhanced

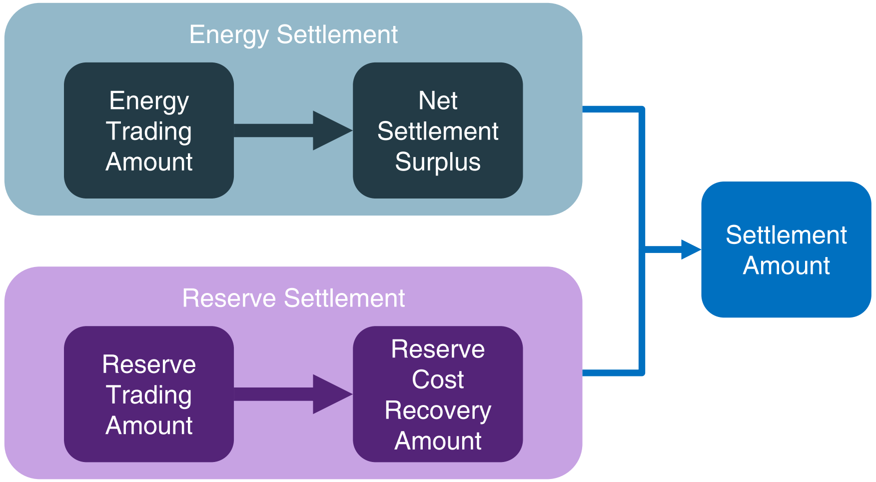


PART	ETA [A]	NSS Alloc. [B]	Energy Settlement Amount [C]
G1	306,300	0	**306,300**
G2	259,924	0	**259,924**
L1	(6,827)	4,363	**(2,464)**
L2	(765,230)	201,470	**(563,760)**
TOT	**(205,833)**	**205,833**	**0**

No amount remaining with the Market Operator

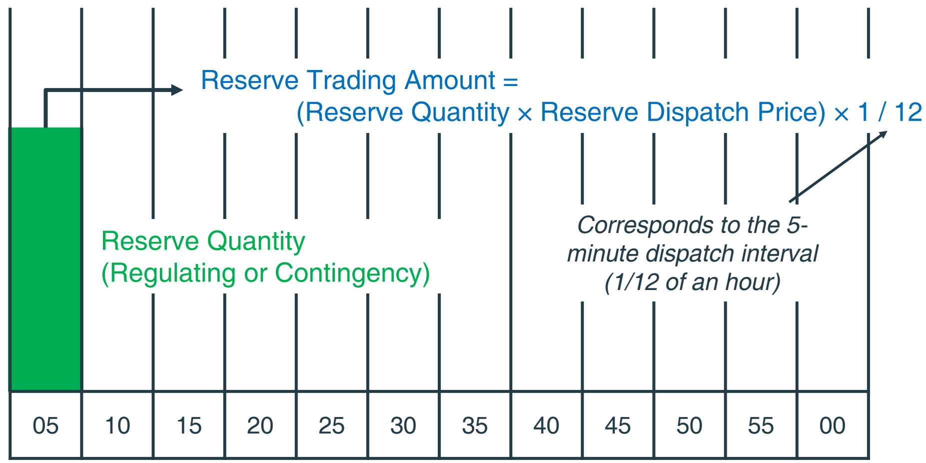
SETTLEMENT CALCULATIONS

Enhanced



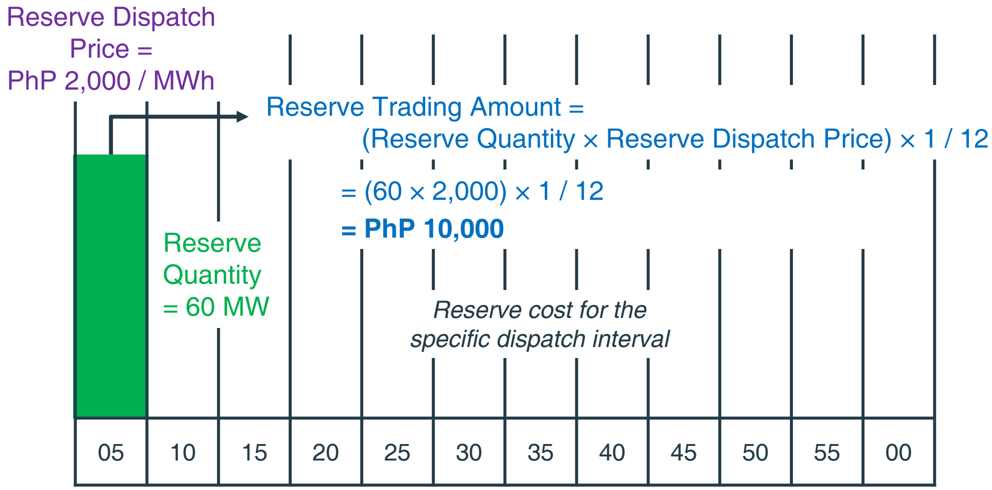
SETTLEMENT CALCULATIONS

Enhanced – Reserve Trading Amount



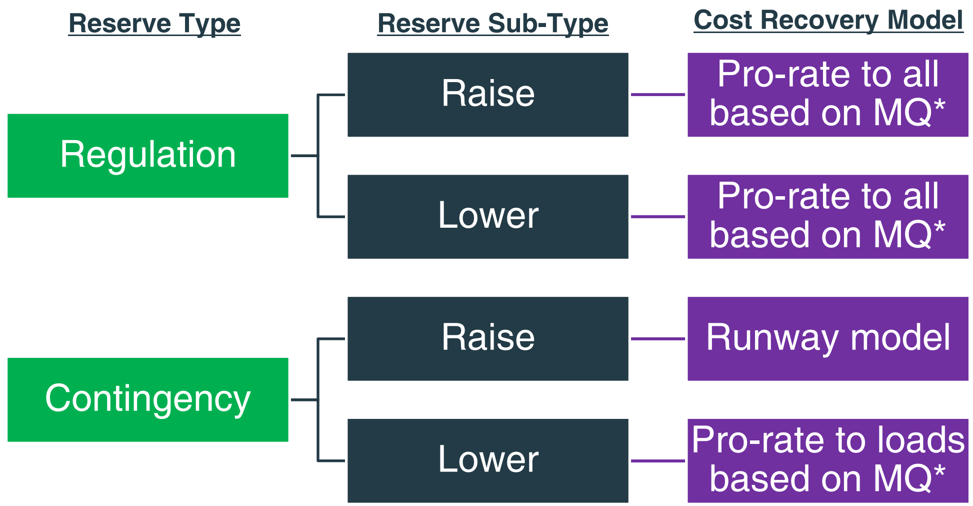
SETTLEMENT CALCULATIONS

Enhanced – Reserve Trading Amount (example)



SETTLEMENT CALCULATIONS

Enhanced – Reserve Cost Recovery



*MQ – metered quantity

SETTLEMENT CALCULATIONS

Enhanced – Reserve Cost Recovery (example)

Regulation

- Raise — Pro-rate to all based on MQ*
- Lower — Pro-rate to all based on MQ*

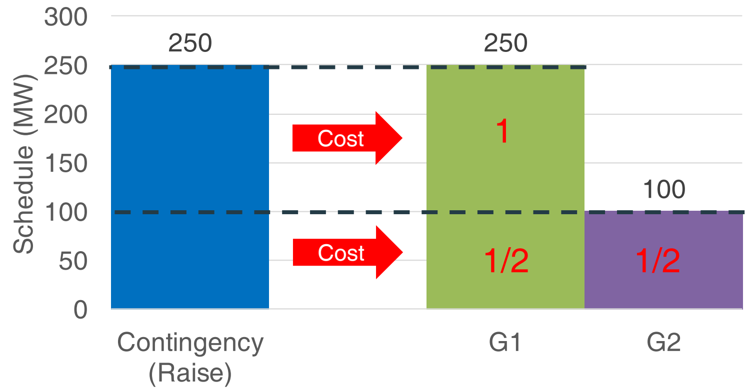
	Cost (PhP)
Raise	20,000
Lower	10,000
TOTAL REGULATION (RR COST)	30,000

	Metered Quantity, MQ (MWh)	Cost Recovery Amount (PhP) $\left[\frac{MQ}{TOTAL\ MQ} \times RR\ COST\right]$
G1	252	(10,726)
G2	103	(4,382)
L1	150	(6,382)
L2	200	(8,509)
TOT	**705**	**(30,000)**

SETTLEMENT CALCULATIONS

Enhanced – Reserve Cost Recovery (example)

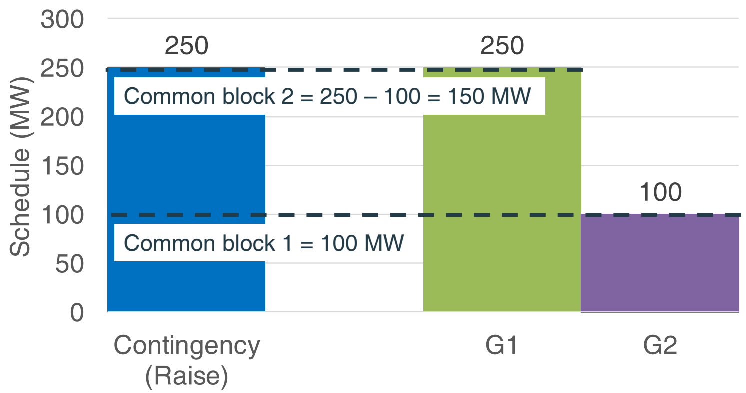
Contingency — Raise — Runway model



SETTLEMENT CALCULATIONS

Enhanced – Reserve Cost Recovery (example)

Contingency — Raise — Runway model



SETTLEMENT CALCULATIONS

Enhanced – Reserve Cost Recovery (example)

Contingency — Raise — Runway model

Ex. RDP = PhP 2,500 / MWh

For common block 1 (100 MW),

$RTA_{CB1} = 100 \times 2{,}500 \times 1 / 12 = \text{PhP } 20{,}833$

$RCRA_{CB1} = 20{,}833 \times 1 / 2 = \text{PhP } 10{,}417$

For common block 2 (150 MW),

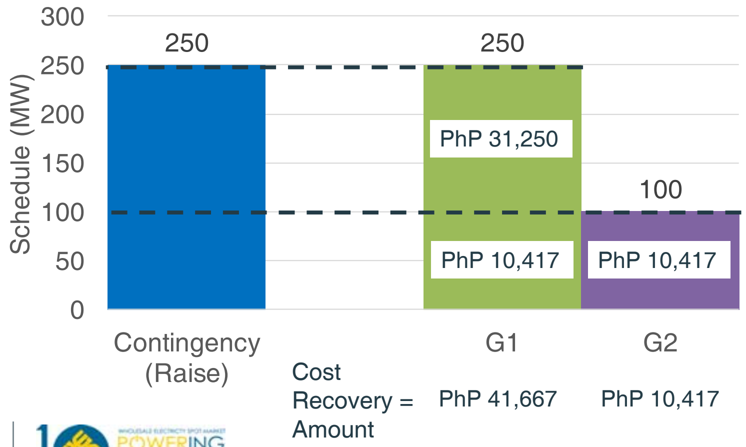
$RTA_{CB2} = 150 \times 2{,}500 \times 1 / 12 = \text{PhP } 31{,}250$

$RCRA_{CB2} = 31{,}250 \times 1 = \text{PhP } 31{,}250$

SETTLEMENT CALCULATIONS

Enhanced – Reserve Cost Recovery (example)

Contingency — Raise — Runway model



SETTLEMENT CALCULATIONS

Enhanced – Reserve Cost Recovery (example)

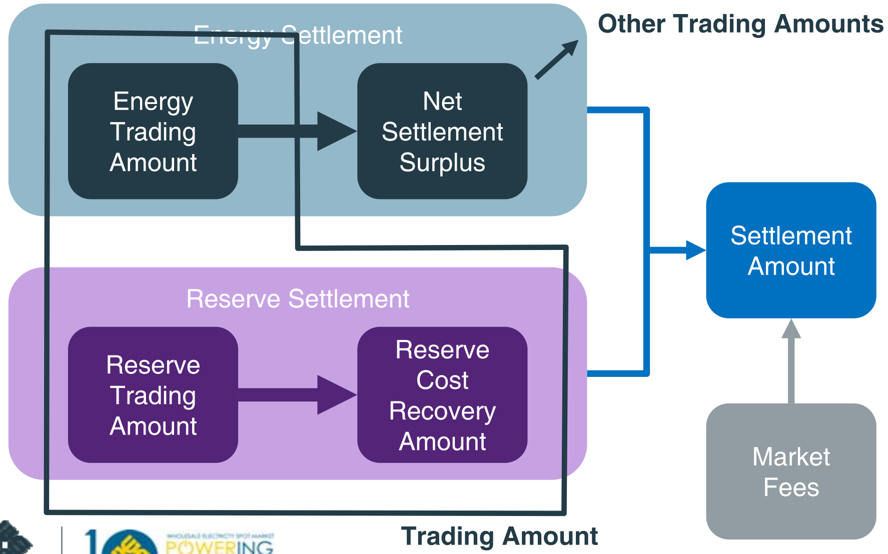
Contingency — Lower — Pro-rate to loads based on MQ*

	Cost (PhP)
CONTINGENCY – LOWER (CL COST)	20,000

	Metered Quantity, MQ (MWh)	Cost Recovery Amount (PhP) $\left[\frac{\text{CUS MQ}}{\text{TOTAL CUS MQ}} \times \text{CL COST}\right]$
G1	252	N/A
G2	103	N/A
L1	150	(8,571)
L2	200	(11,429)
TOT	**705**	**(20,000)**

SETTLEMENT AMOUNT

Enhanced WESM Design



SETTLEMENT AMOUNT

Enhanced WESM Design

Settlement Amount = Trading Amounts +

Other Trading Amounts –

Market Fees

SUMMARY

KEY DESIGN ENHANCEMENTS

FEATURE	OLD	NEW	RATIONALE
Dispatch Interval	1 Hour	5 minutes	Lessen intra-hour deviations and reduce imbalances
Pricing	Ex-ante & Ex-post	Ex-ante only	Shorter dispatch interval will not require ex-post runs
Market Re-runs	Manual Market re-runs	Automatic pricing re-runs	Improve availability of prices in real time
Consideration of Pmin	Priority dispatch	Submitted as offer	Encourage participants to offer all its capacities
Scheduling/ Trading of Energy and Reserves	Results of central scheduling of reserves are input to energy-only market	Co-optimized energy and reserves	Ensuring optimal scheduling of energy and reserves
Settlements	One Hour interval and resolution	One Hour interval and 5-minute resolution	Reflect actual market results
	Two-Part Settlement	One-Part Settlement	Ex-ante pricing only
Administered Prices	Calculated during settlement	Calculated by NMMS	Real-time pricing
PSM Settlement	Adjustments made during settlement	PSM prices by NMMS is binding	Real-time pricing
MRU Settlement	GPI plus additional compensation	Market price plus additional compensation	Real-time pricing

Philippine Electricity Market Corporation

END OF PRESENTATION

WESM Works.

WESM Helpdesk Ticketing System
www.wesm.ph/wesm-helpdesk

+63.2.318.WESM (9376)

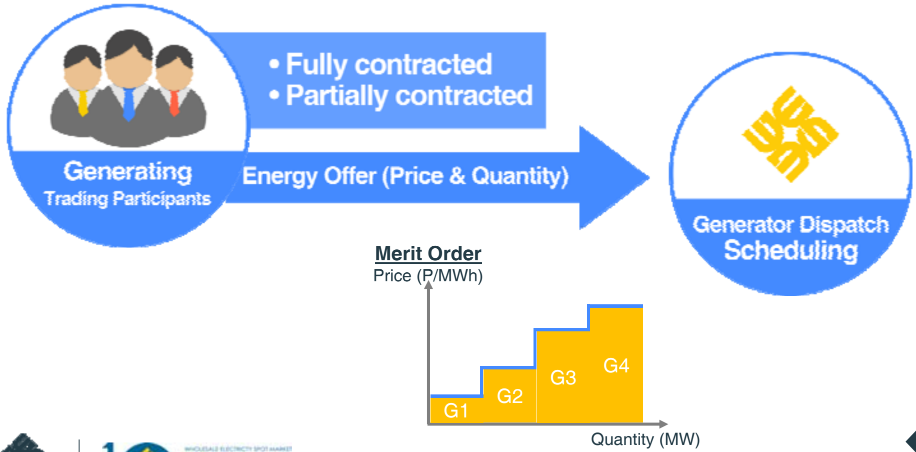
+63.2.634.0985

www.wesm.ph

GUIDING PRINCIPLES

Gross pool

- All energy is traded through the WESM (i.e., mandatory market)

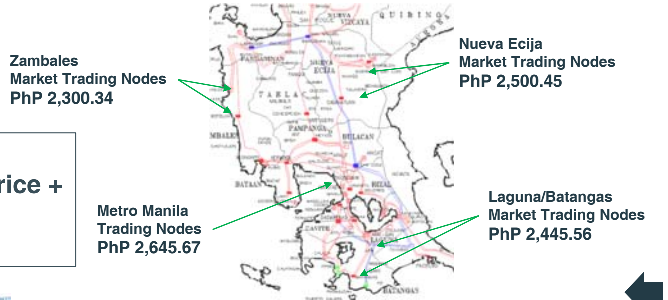


GUIDING PRINCIPLES

Locational Marginal Pricing / Nodal Pricing

- Marginal price is computed at each node or location in the power system to reflect transmission line loss or congestion, or both.

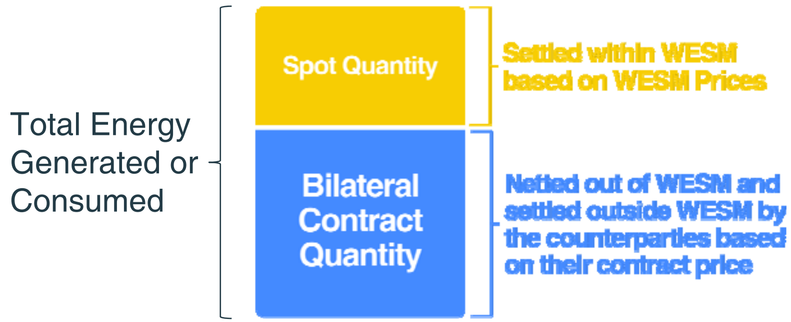
LMP =
System Marginal Price +
Cost of Losses +
Congestion Cost



GUIDING PRINCIPLES

Net Settlement

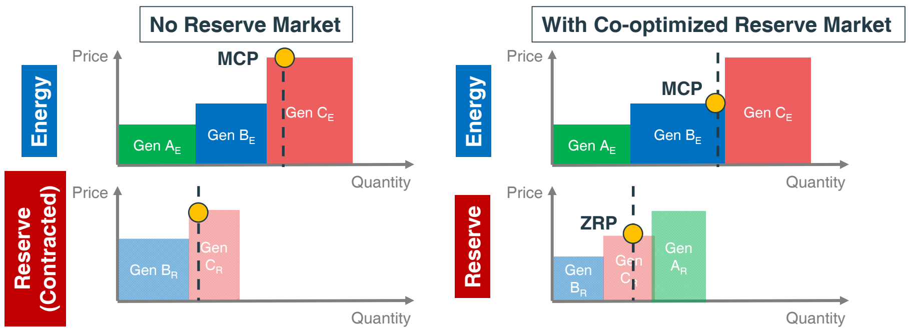
- Participants may declare bilateral contract quantities
- Only spot quantity is settled at market price (nodal)



GUIDING PRINCIPLES

Energy and Reserve Co-optimization

- Energy and reserve schedules are jointly determined under a single solution



Energy and reserve markets are scheduled separately

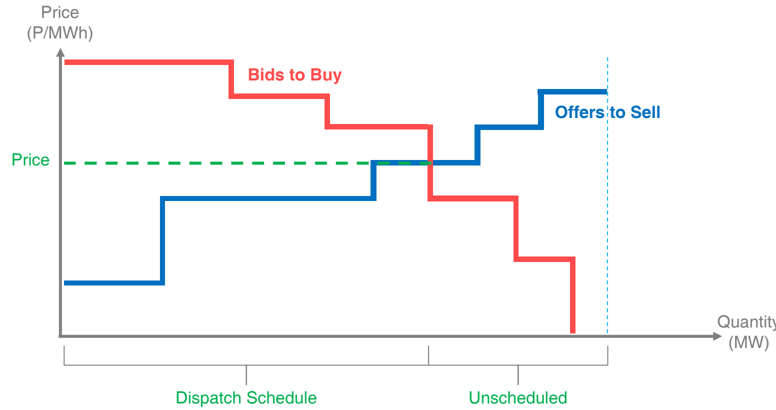
Energy and reserve market are optimized together

Advantages of Co-Optimized Reserve Market:
- All available capacities can be seen by the WESM
- Determination of optimal schedules and prices between energy and reserves with the least over-all cost
  - Mitigate artificial under-generation

GUIDING PRINCIPLES

Demand Bidding

- Customers submit bids at the price they are willing to pay



GUIDING PRINCIPLES

Self Commitment

- Trading participants are responsible for the management of their technical operations, unit commitment decisions and other market risks through submission of offers to the WESM

GUIDING PRINCIPLES

RULES-BASED

- Governing rules are applied to all
  - o Level playing field
  - o Consulted with stakeholders

Date/Venue	Attendees	Agenda
15-18 April 2013 at PEMC Office	DOE, PEMC, NGCP-SO, and other stakeholders (AES-MPPCL, FGP Corporation, First Gas, MERALCO, NPC, PANASIA, PSALM, SNAP, and SPPC)	Phase 1 issues
17-20 June 2013 at PEMC Office	DOE, PEMC, NGCP-SO, and other stakeholders (Aboitiz Power, AES-MPPCL, AP Renewables, Bac-Man, CEDC, CIP II Power Corp., EDC, First Gas, First Gen, GMCP, Green Core, HEDCOR, Luzon Hydro, Northwind, NPC, One Subic Power, PANASIA, PEDC, Petron, SEM-Calaca, SPC Island Power Corp., SMC Global, SNAP, Therma Luzon, Therma Mobile, Toledo Power Company 1590 EC/Vivant)	• Phase 1 findings and recommendations • Phase 2 issues
12-16 August 2013 at PEMC Office	DOE, GMC, ERC, PEMC, WESM Committees, NGCP-SO, and stakeholders (AES-MPPCL, ALECO, AP Renewables, BENECO, CAGELCO I, CANORECO, CASURECO II, CASURECO IV, CEBECO I, CEC, CELCOR, CENECO, DECORP, GUIMELCO, GN Power, IEEC, ILECO II, ILECO III, INEC, LEYECO, LEYECO II, MERALCO, NEECO, NEECO-Area I, PEDC, San Jose City Electric Cooperative, SMEC, SNAP-Benguet Inc., SNAP-Magat Inc., SPC Island Corporation, TARELCO II, VECO)	Phase 2 findings and recommendations
13-15; 19-20 November 2013 at PEMC Office	DOE, ERC, PEMC, WESM Committees, NGCP-SO	Phase 3 recommendations
18 November 2013 **Stakeholders' Consultation Meeting at the Development Academy of the Philippines**	DOE, DMC, GMC, ERC, PEMC, NGCP-SO, and stakeholders (1590 EC, Aboitiz Power, AES Masinloc, Angeles Power, AP Renewables, BATELEC II, BENECO, CAGELCO I, CAGELCO II, CANORECO, CASURECO II, Clark Electric Distribution Corporation, Dagupan Electric Corporation, EAUC, Ecozone Power Management Inc., FLECO, GN Power, Green Core Geothermal Inc., Guimaras Electric Cooperative, INEC, MERALCO, MOPRECO, MPower, NEECO II – Area I, NEECO – Area II, NORECO I, Northern Renewables, PANASIA, Panay Power Corporation, PENELCO, Pilipinas Shell Petroleum Corporation, PERC, PSALM, Samar II Electric Cooperative Inc., SMEC, SEM-Calaca, SNAP-Benguet, South Premier Power Corp., SPC Island Power Corp., SPDC, TARELCO II, Tarlac Electric Inc., Team Energy, Therma Luzon, Therma Mobile, Toledo Power Company, TPEC, VECO, Vivant, VRESCO)	Phase 1, Phase 2, and Phase 3 findings and recommendations