Philippine Electricity
Market Corporation

WESM PRICE DETERMINATION METHODOLOGY

Expository Presentation

20 September 2017

MinDA Office, Davao City

OUTLINE

BACKGROUND

DESIGN ENHANCEMENTS

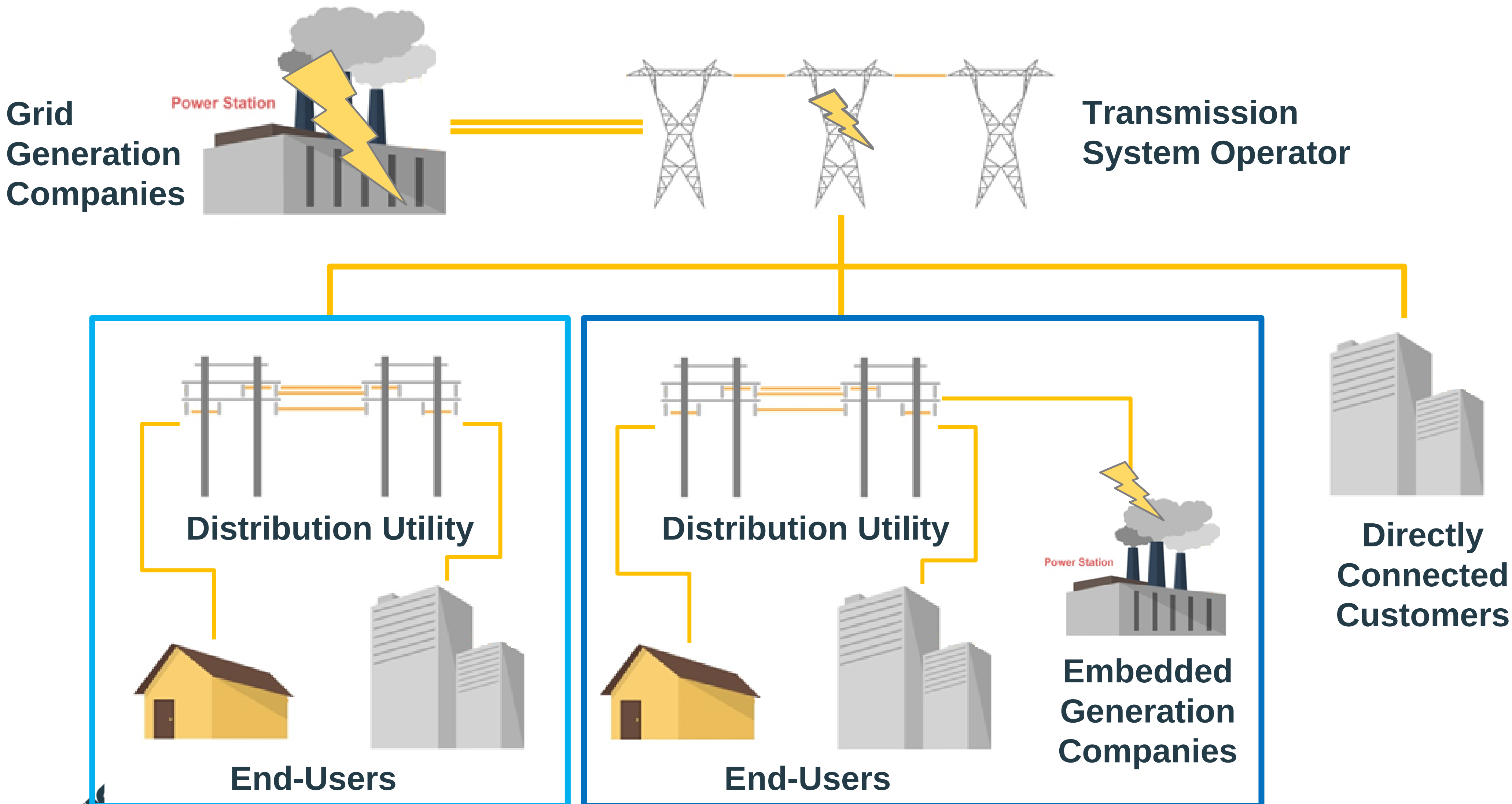
PRICE DETERMINATION METHODOLOGY (PDM) AMENDMENTS

SUMMARY

BACKGROUND

BACKGROUND

How is power delivered to customers?



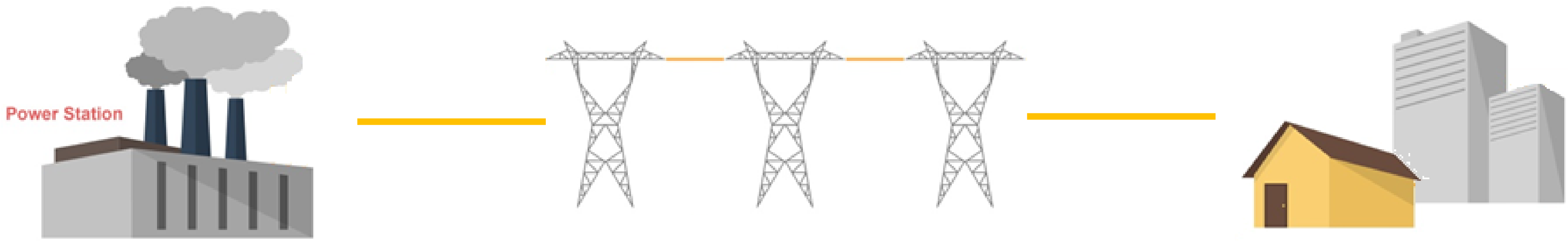
BACKGROUND

Supply and Demand Balancing

- Instantaneous production and consumption
- Cannot be economically stored

…requires a corresponding real-time increase in generation, and vice versa.

Demand increase…



Real-time centralized scheduling and balancing of supply and demand

Market Operator

Market-based Scheduling

Balancing

System Operator

BACKGROUND

Transition to competitive regime

Electric Power Industry Reform Act (EPIRA)

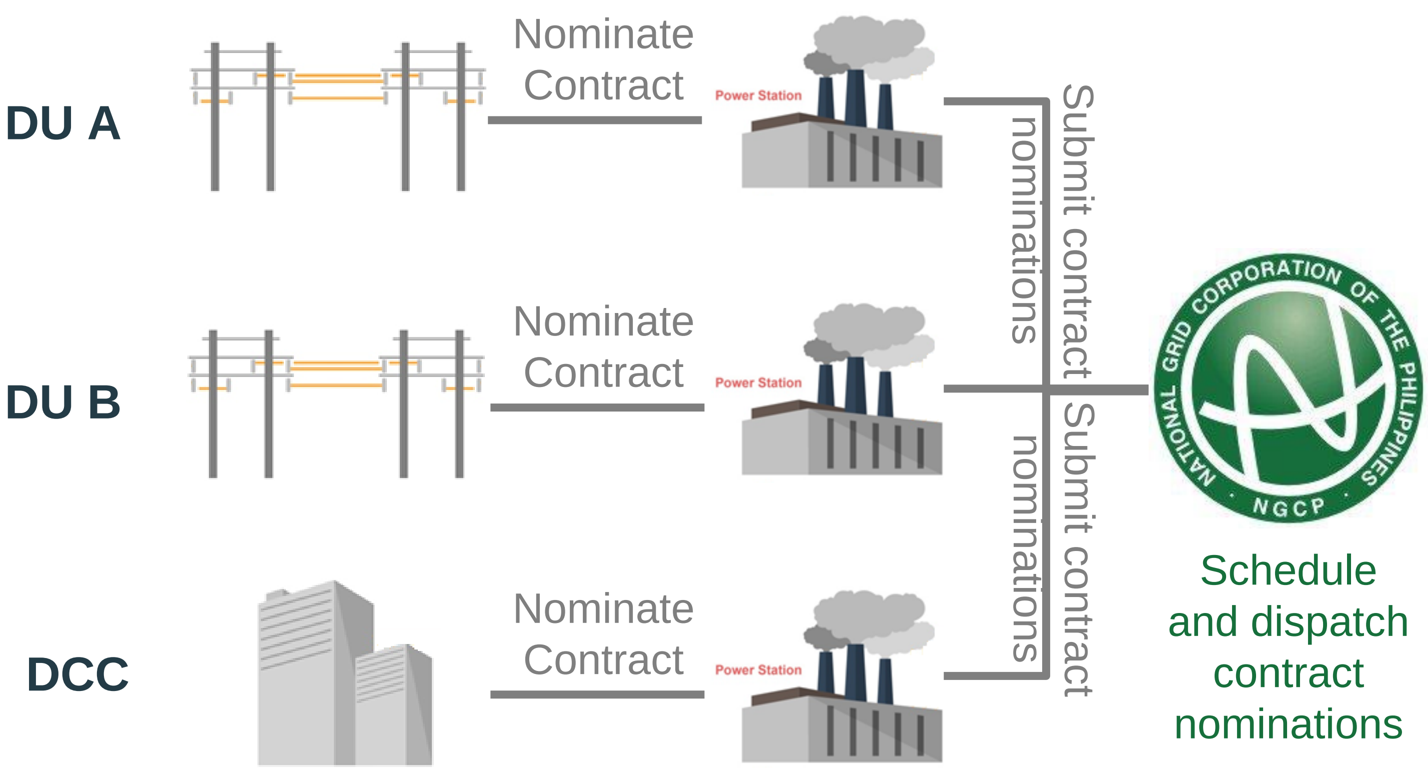
Declaration of Policy

"(c) Transparent and reasonable prices … in a regime of free and fair competition … to achieve greater operational and economic efficiency

(d) To enhance the inflow of private capital and broaden the ownership base of the power generation"

BACKGROUND
Scheduling

Interim Dispatch Protocol



Challenges

- *Cheaper available capacities may not be fully utilized due to contracts*
- *Customers with contract deficiencies cannot source from other available generators*
- *Generation for system security reasons is shouldered by counterparty*

- *Customers may re-nominate contracts*
- *Real-time variations are addressed by reserves*

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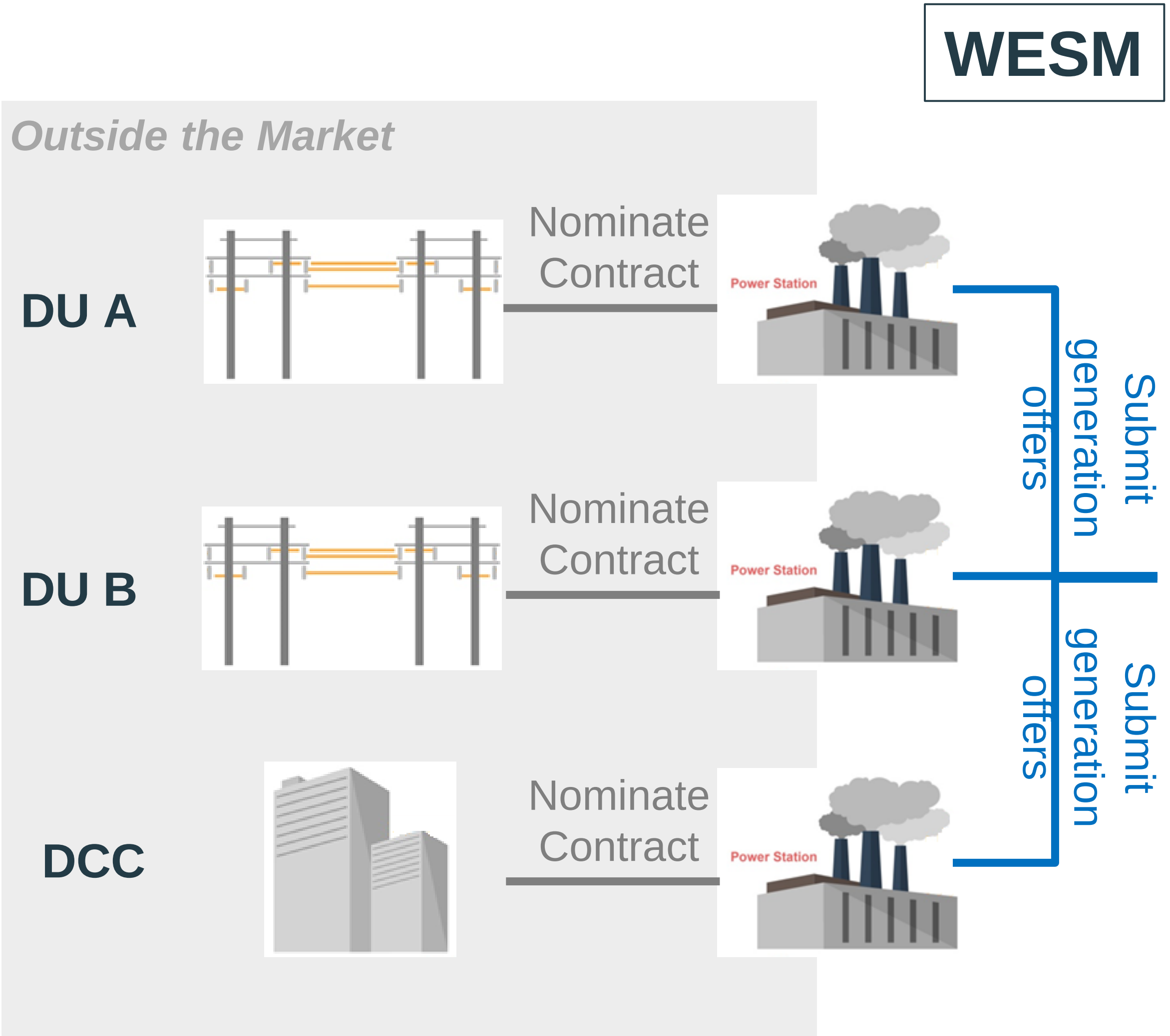
WHOLESALE ELECTRICTY SPOT MARKET POWERING PROGRESS 2006 - 2016

BACKGROUND

Scheduling



Features

- *All capacities are optimized to serve all demand*
- *Generation for system security reasons is shared by whole region*

- Forecast demand
- Schedule generation based on offers

BACKGROUND

Benefits of WESM

System-Optimized Schedules

- Current optimization of individual contract portfolios result in suboptimal system generation mix
- WESM optimizes generation cost for whole system

Full Availability of Capacities

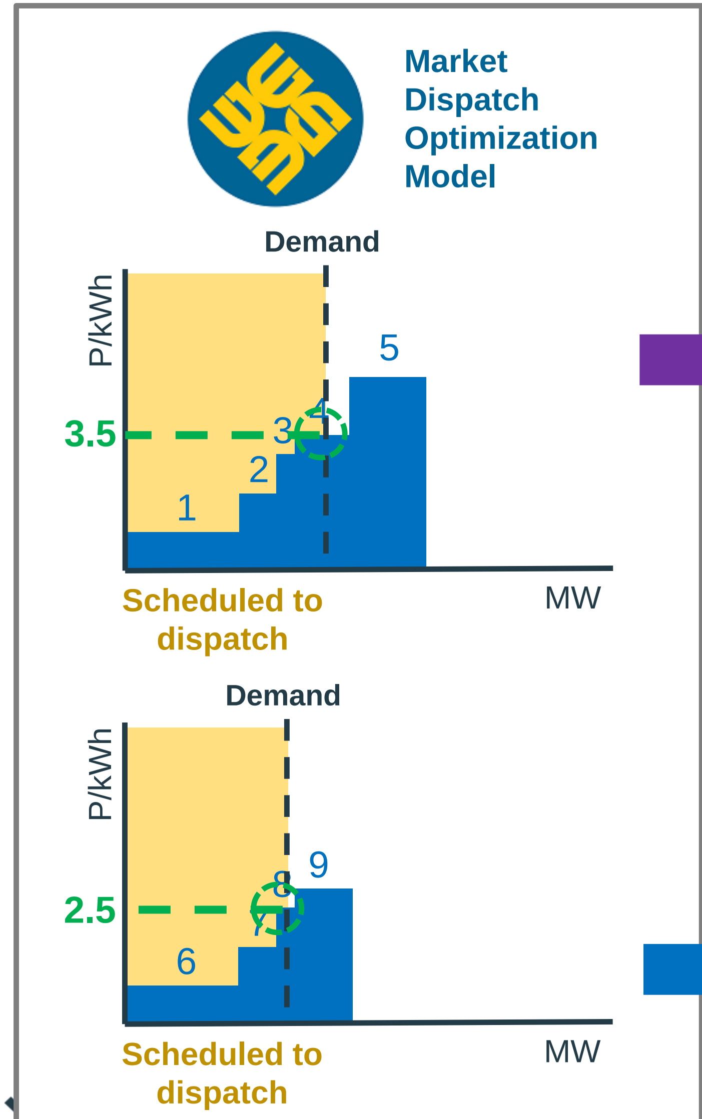
- Generators currently only dispatch to serve their counterparties
- In the WESM, generators can be dispatched to serve any demand
- Any generation can be utilized in the WESM to address congestion

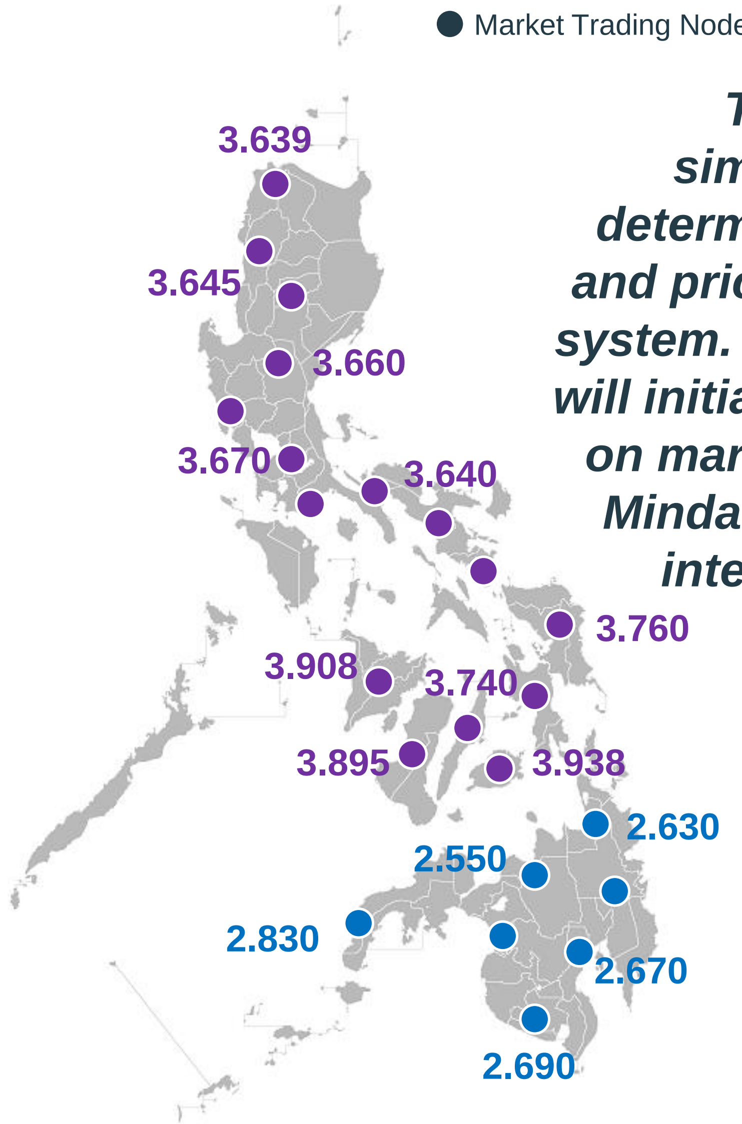
Transparent and Shared Security and Reliability Costs

- Security-based dispatch is currently shouldered by counterparties of generators
- In the WESM, costs to address security concerns are made transparent and shared by the whole region

BACKGROUND

WESM Scheduling with Mindanao





The WESM simultaneously determines schedules and prices for the whole system. Mindanao results will initially be based only on market outcomes in Mindanao prior to the interconnection.

BACKGROUND
Trading in the WESM

Generators

Outside the market

Ensure availability of generating units

↓

Submit offers for scheduling

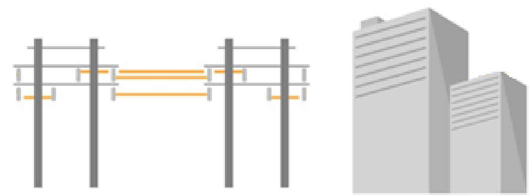
↓

If any, declare bilateral contract quantities

↓

Settled for production not covered by contracts

Customers



Optimize energy sourcing from contracts and WESM

↓

Utilize electricity
(No bidding is required to buy from the WESM)

↓

If any, confirm bilateral contract quantities

↓

Settle consumption not covered by contracts and, if applicable, losses & congestion

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

BACKGROUND

Guiding Principles

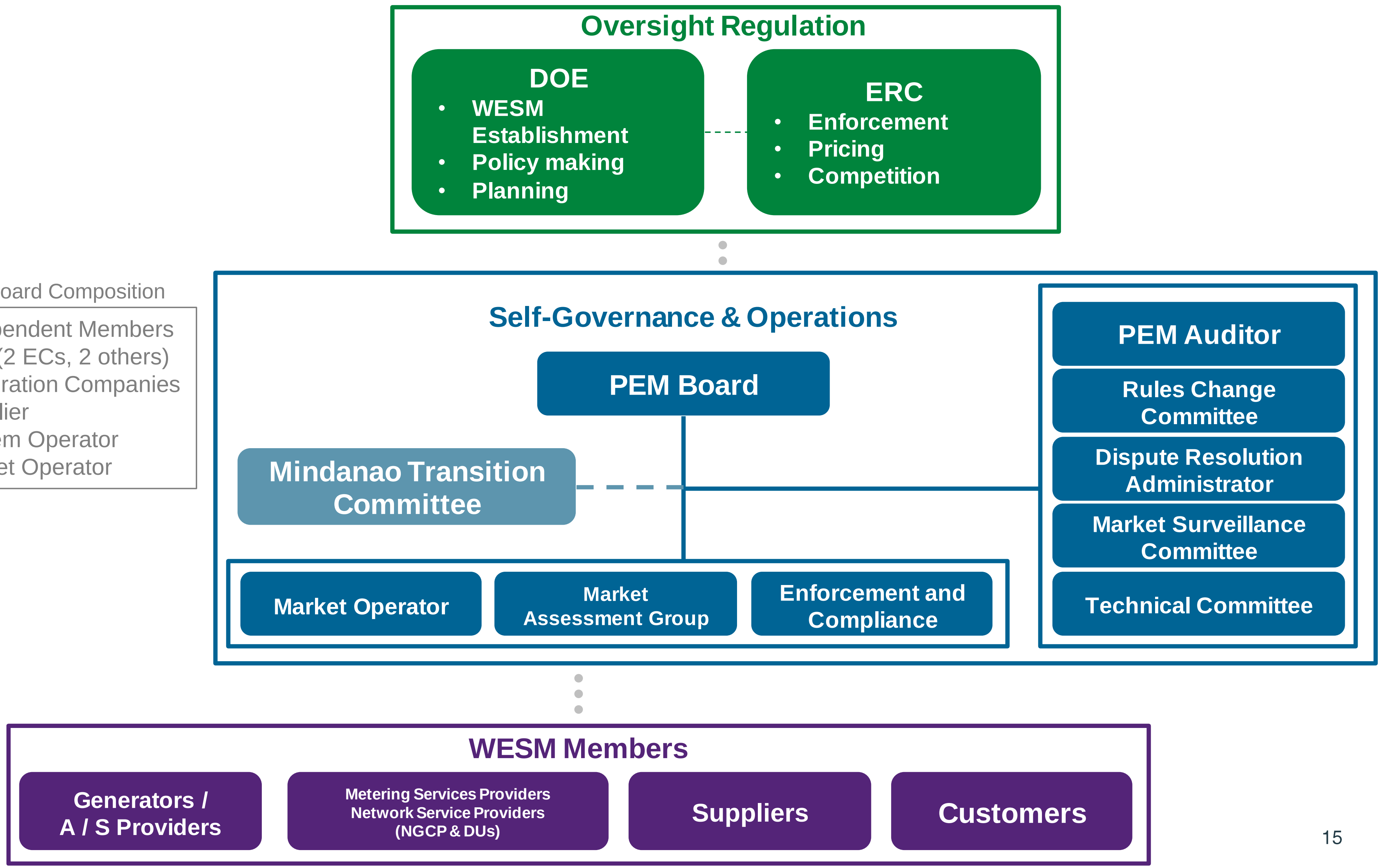
- Gross Pool
- Locational Marginal Pricing / Nodal Pricing
- Net Settlement
- Energy and Reserve Co-optimization
- Demand Bidding
- Self commitment
- Rules-based

BACKGROUND

Structure

PEM Board Composition

4 Independent Members
4 DUs (2 ECs, 2 others)
4 Generation Companies
1 Supplier
1 System Operator
1 Market Operator



WESM DESIGN ENHANCEMENTS

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

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 PRICE DETERMINATION METHODOLOGY (PDM) AMENDMENTS

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)
  - Includes price substitution methodology in cases of extreme nodal price separation
  - Pricing during market intervention and suspension
- Calculation of settlement amounts net of bilateral contracts

REVISED PDM MANUAL STRUCTURE

Contents

PDM (2006)

- Market Dispatch Optimization Model
- Billing and Settlement

Enhancements

***Revised* PDM**

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

Other pricing & settlement manuals:

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

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WHOLESALE ELECTRICTY SPOT MARKET POWERING PROGRESS 2006 - 2016

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

SUMMARY OF ENHANCEMENTS TO THE PDM

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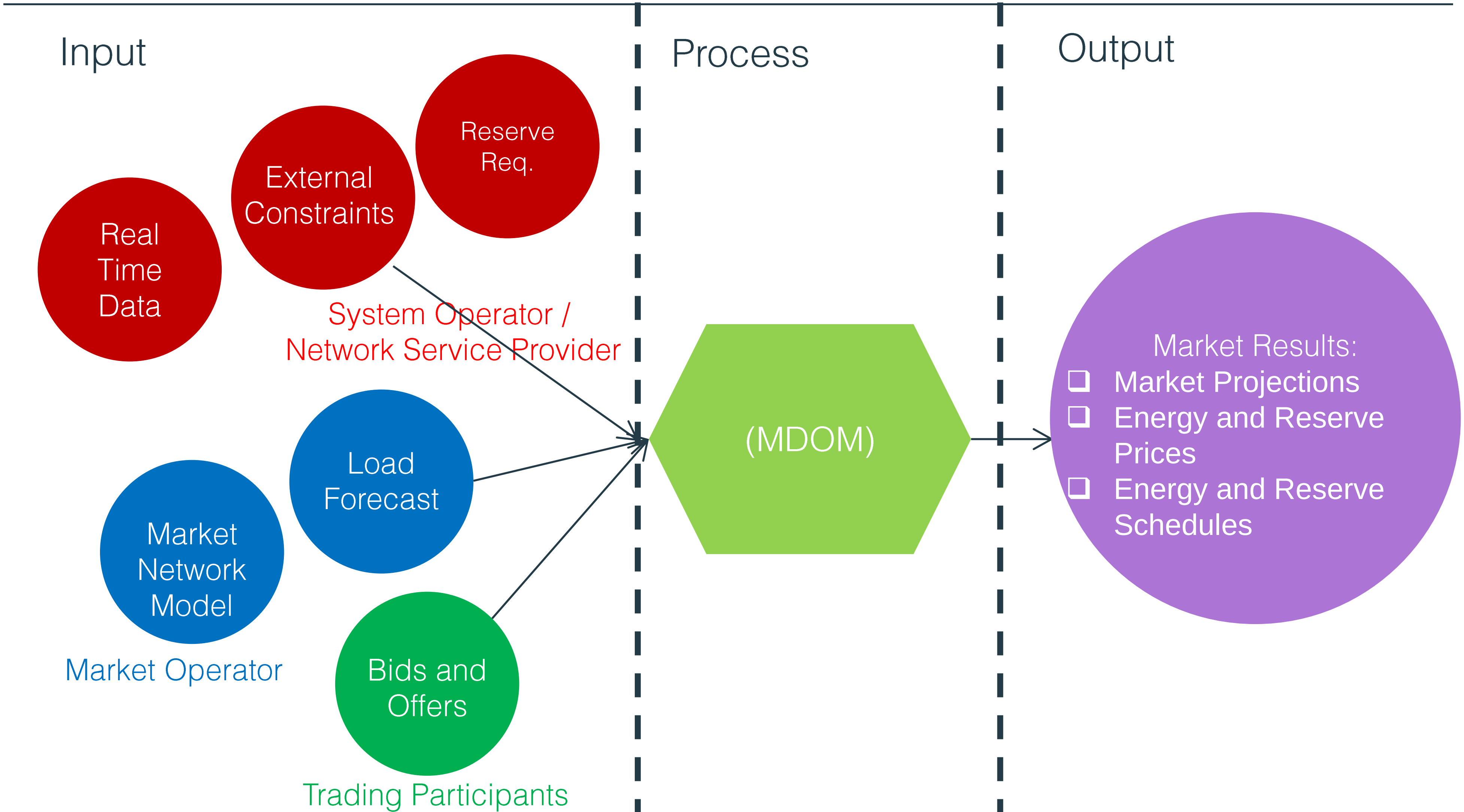
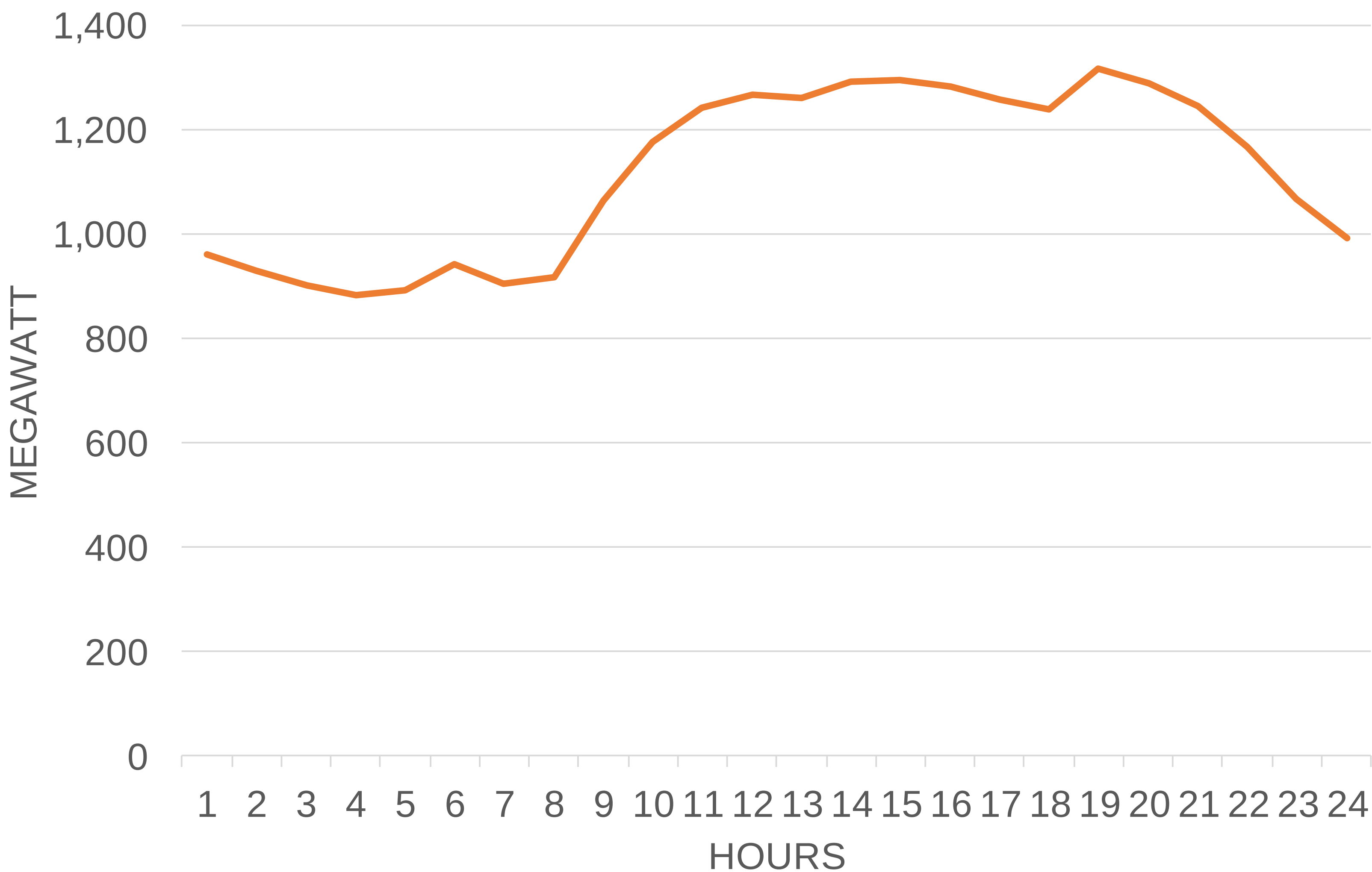
MARKET DISPATCH OPTIMIZATION MODEL (MDOM)

Overview



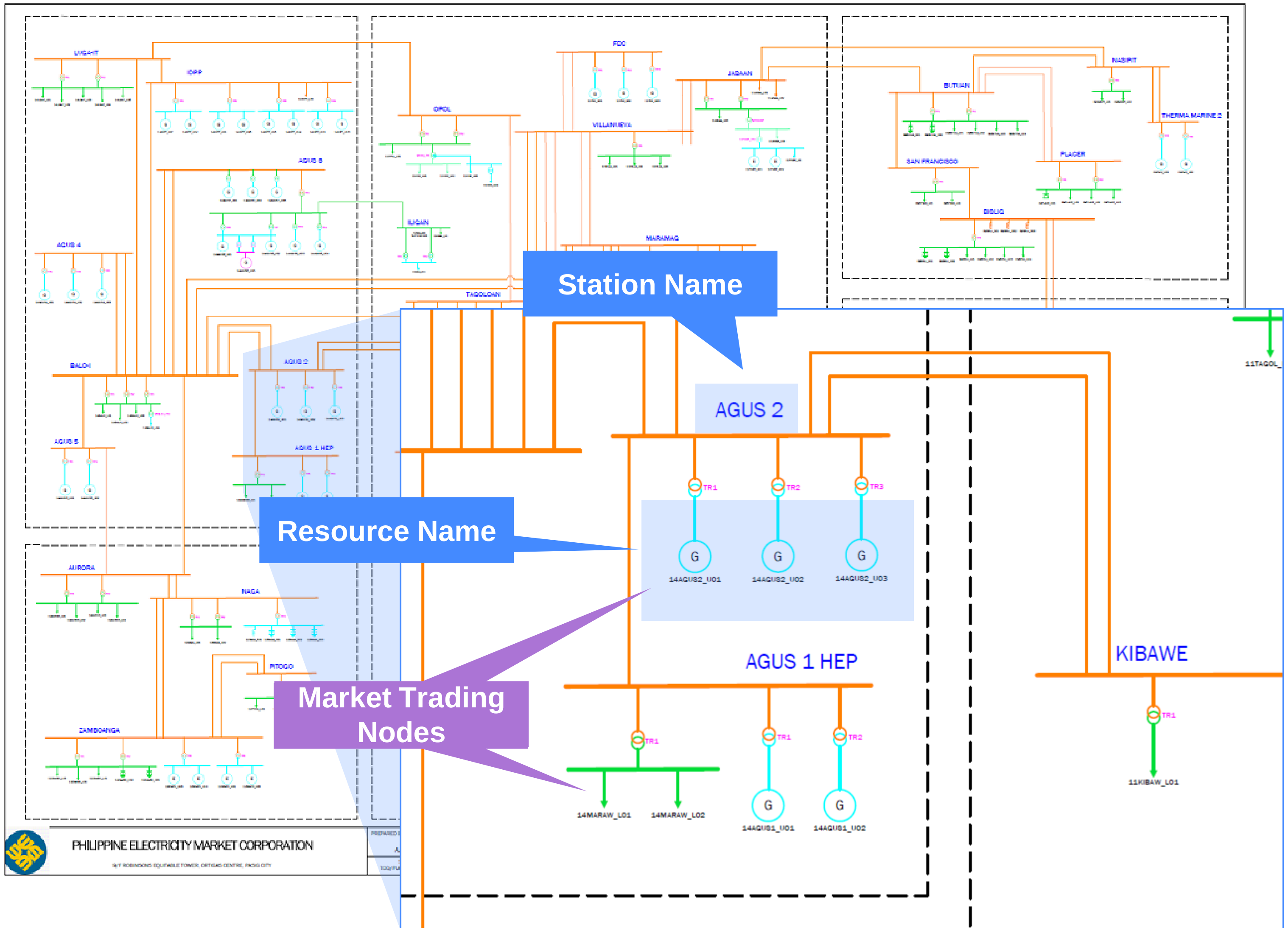
MDOM

MDOM Input – Load Forecast



MDOM

MDOM Input – Market Network Model



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MARKET DISPATCH OPTIMIZATION MODEL (MDOM)

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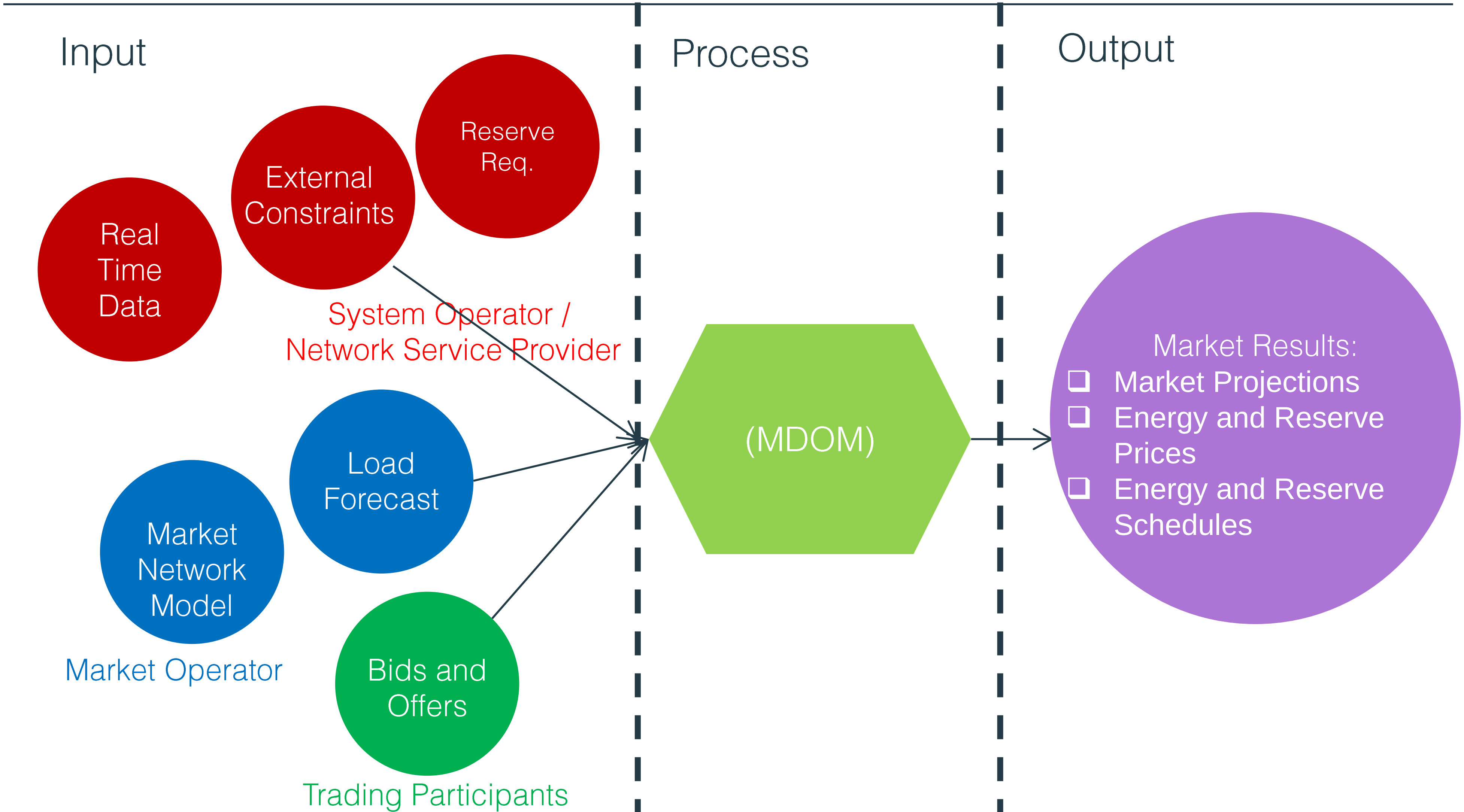

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WHOLESALE ELECTRICTY SPOT MARKET POWERING PROGRESS 2006 - 2016

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

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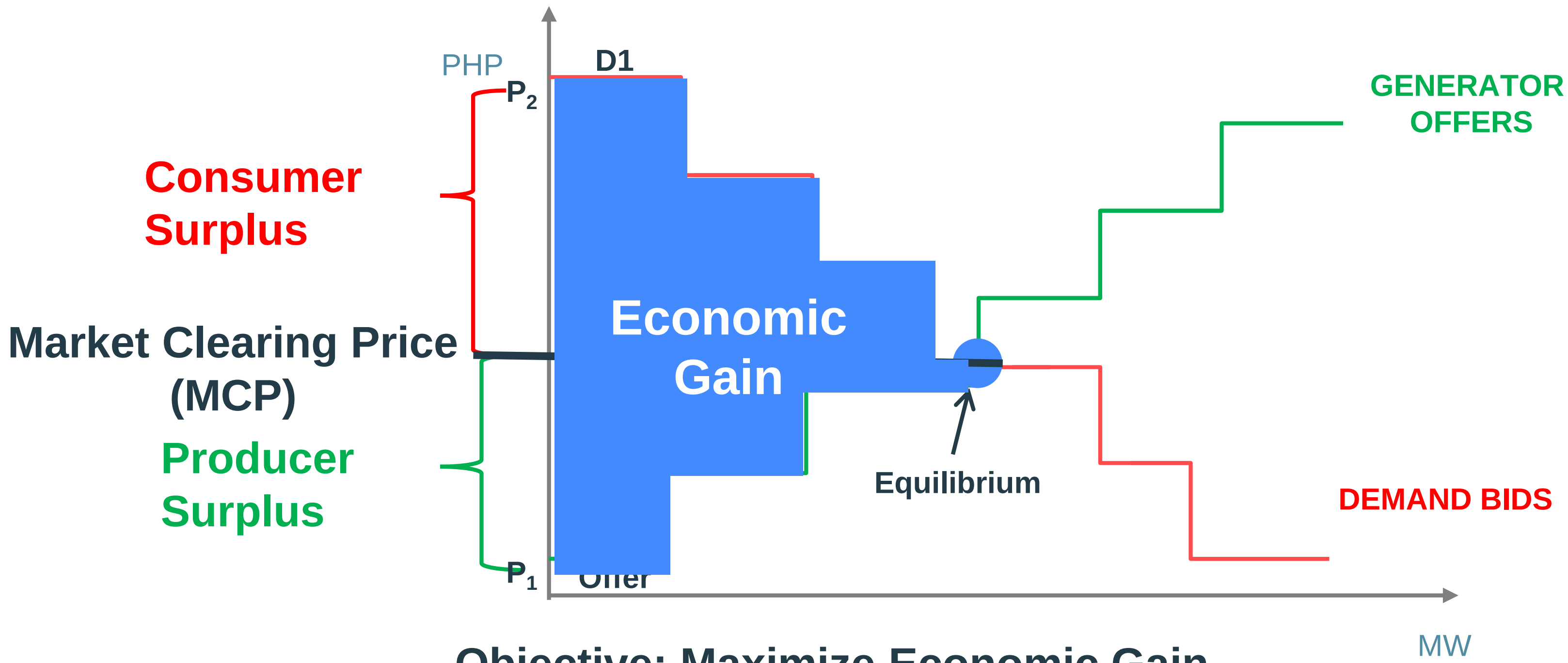
MDOM

Objective Function



Objective: Maximize Economic Gain

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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)

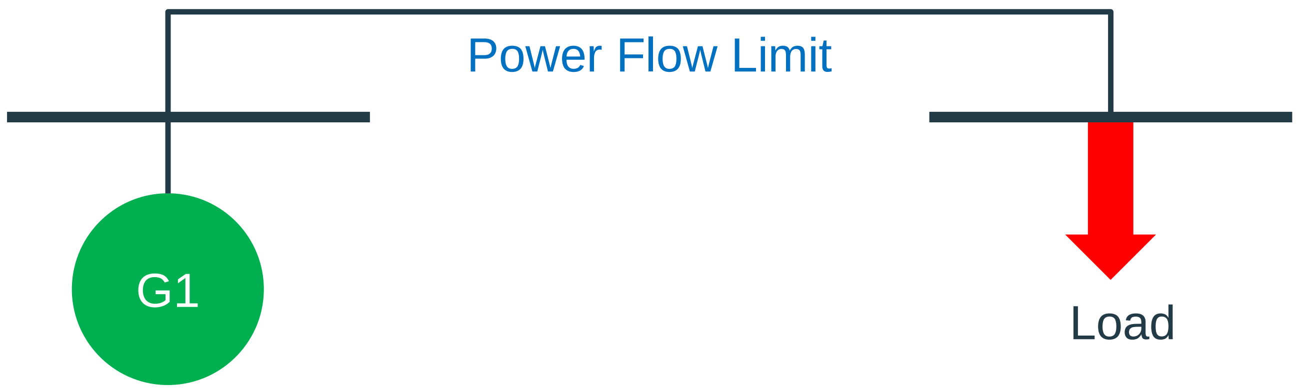
MDOM

Sample Constraints

System Power Balance:

Generation = Load + Losses

Transfer Capacity = 300 MW



Offer: 300 MW @ P 3,000 / MWh

Generator resource energy constraint

250 MW

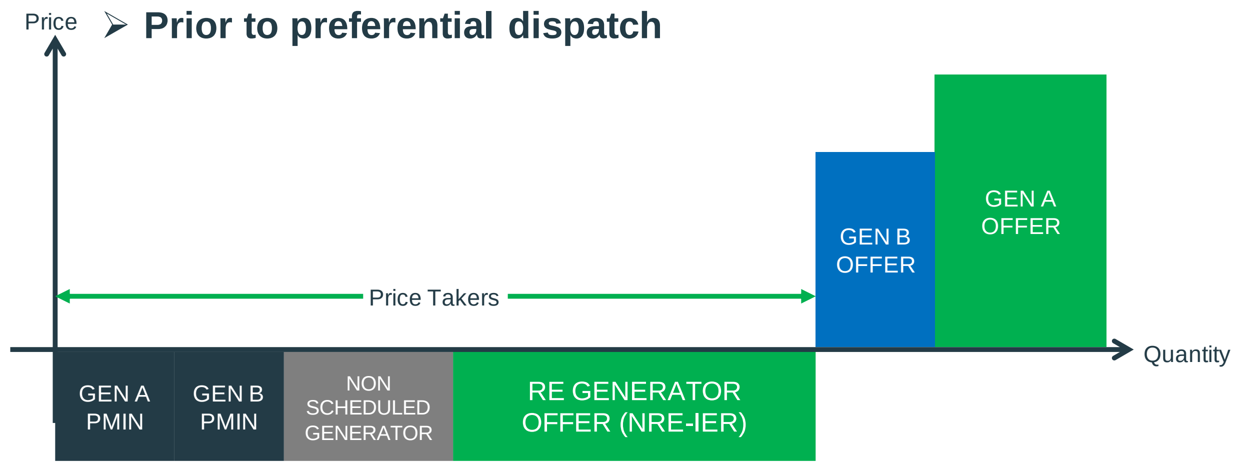
Nodal energy balance constraint

MDOM

Priority-scheduling

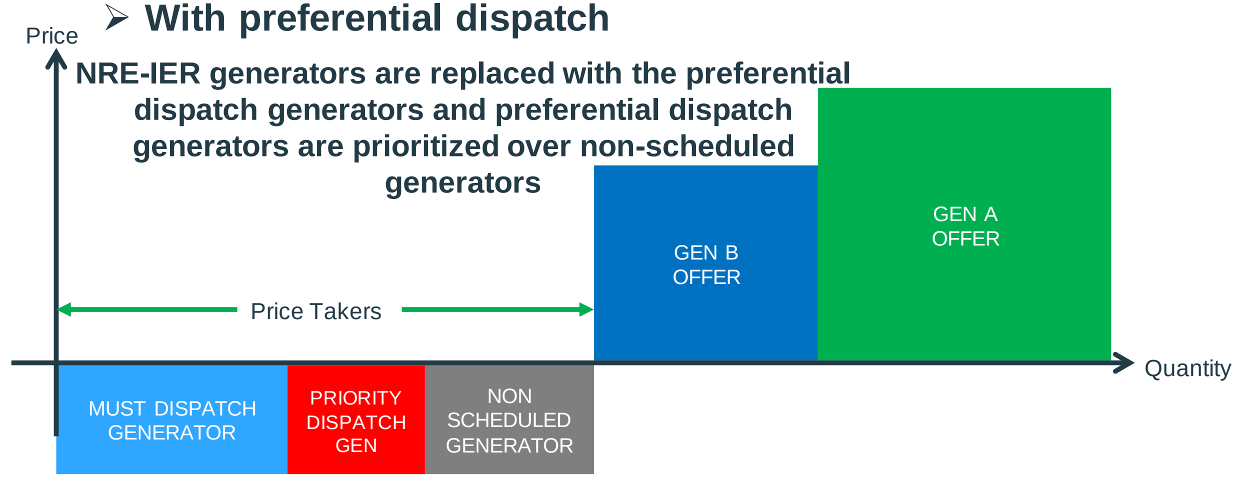
- When restricting dispatch schedules, following hierarchy shall be followed:
  - Market offers of scheduled generating units;
  - Non-scheduled generating units[1];
  - Priority dispatch generating units[2]; and
  - Must dispatch generating units[3].

➢ **Prior to preferential dispatch**



➢ **With preferential dispatch**

NRE-IER generators are replaced with the preferential dispatch generators and preferential dispatch generators are prioritized over non-scheduled generators



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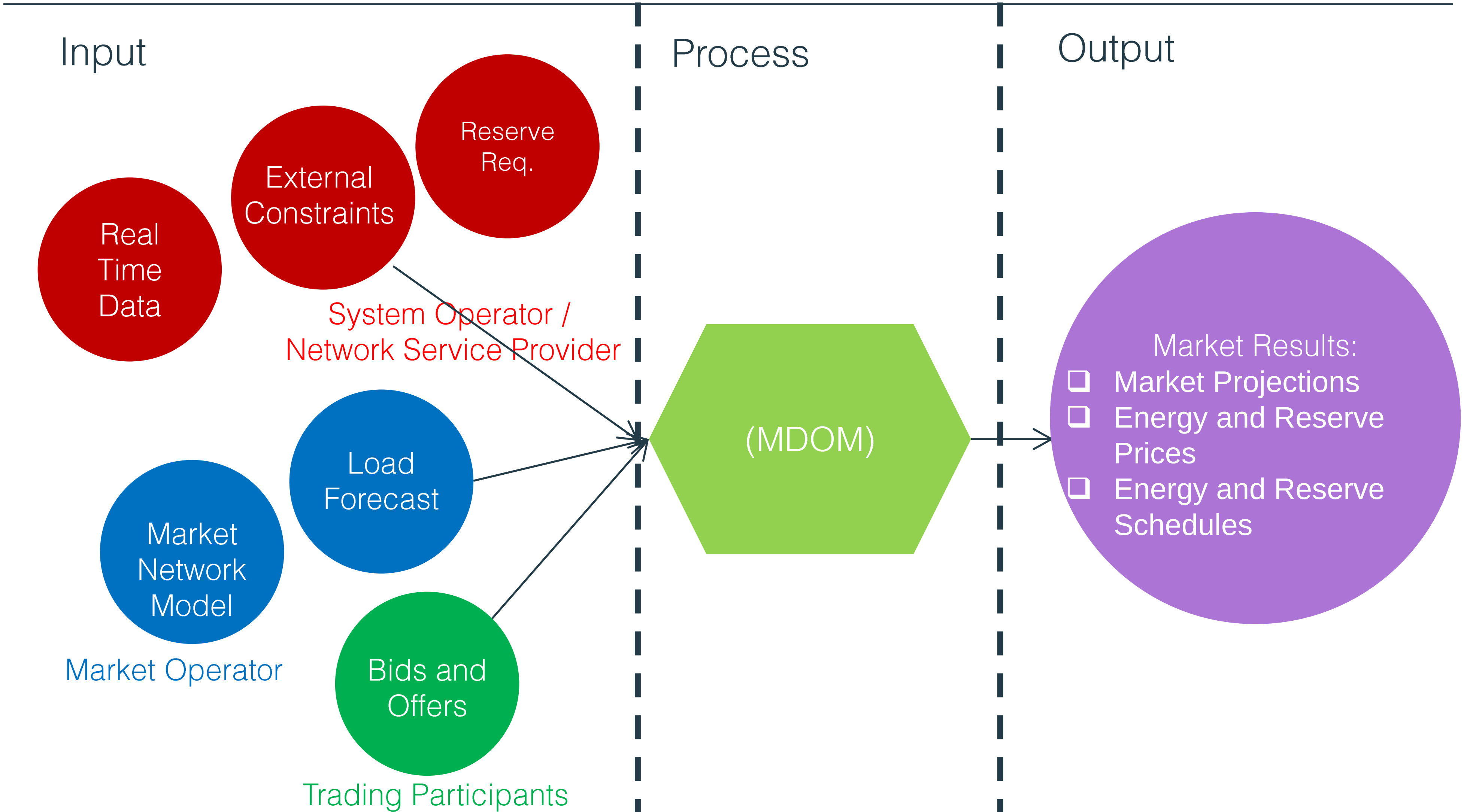
1\ Plants with capacity less than 0.1% of regional peak demand
2\ FIT-qualified biomass plants
3\ Solar, wind, run-of-river hydro plants

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

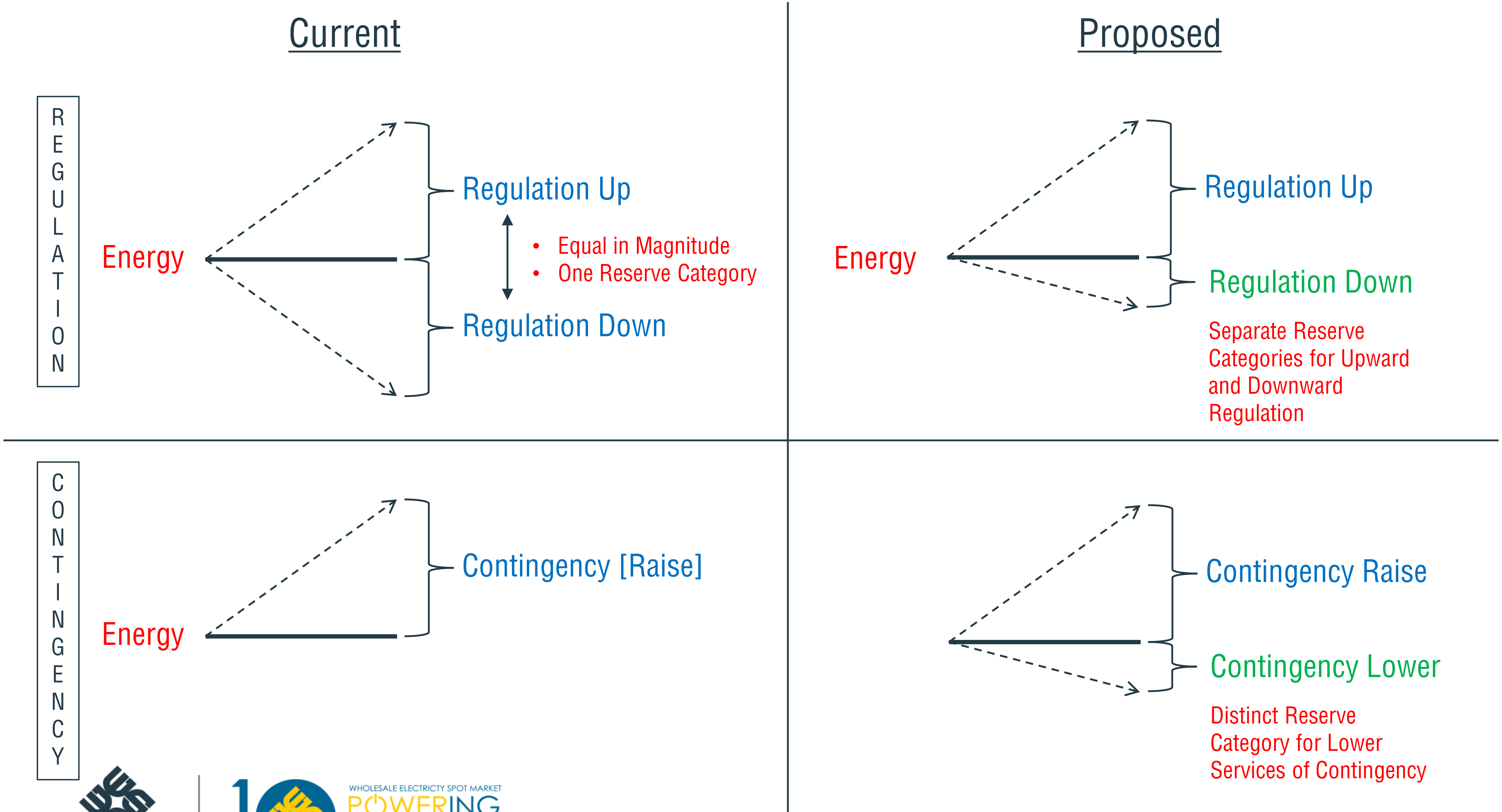
MDOM

Reserves

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

RESERVES

Reserve Categories [Distinction between Raise and Lower Reserves]



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

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

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

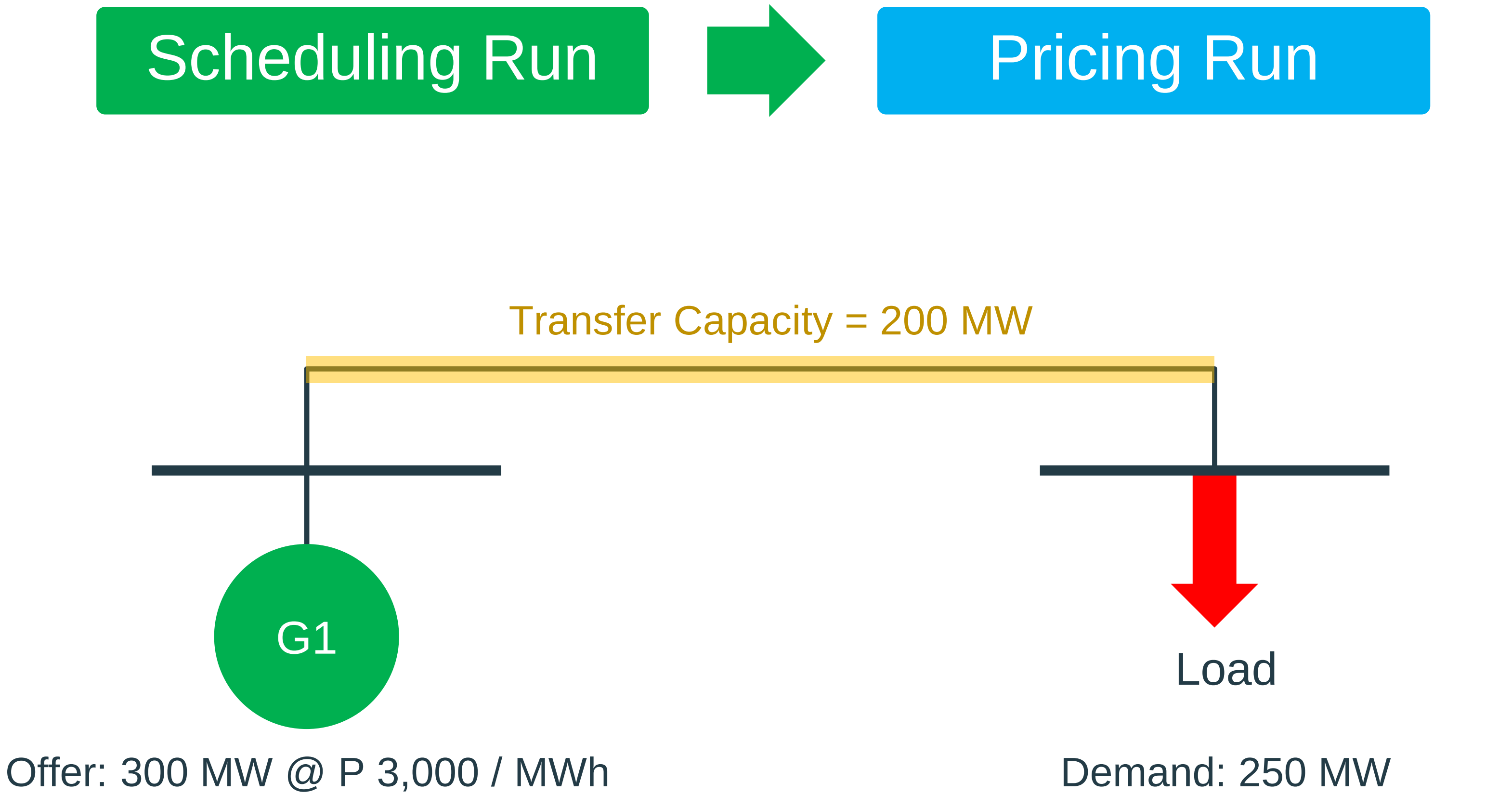
MARKET PRICING RE-RUNS

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.

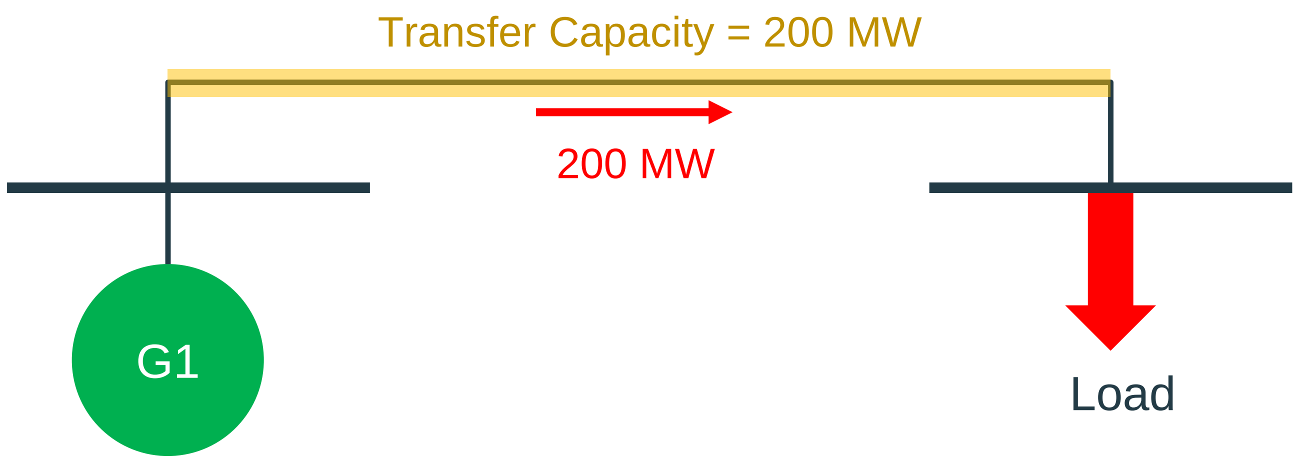
○ Manual re-runs done only for errors due to erroneous input data

MARKET PRICING RE-RUNS



MARKET PRICING RE-RUNS

Scheduling Run → Pricing Run

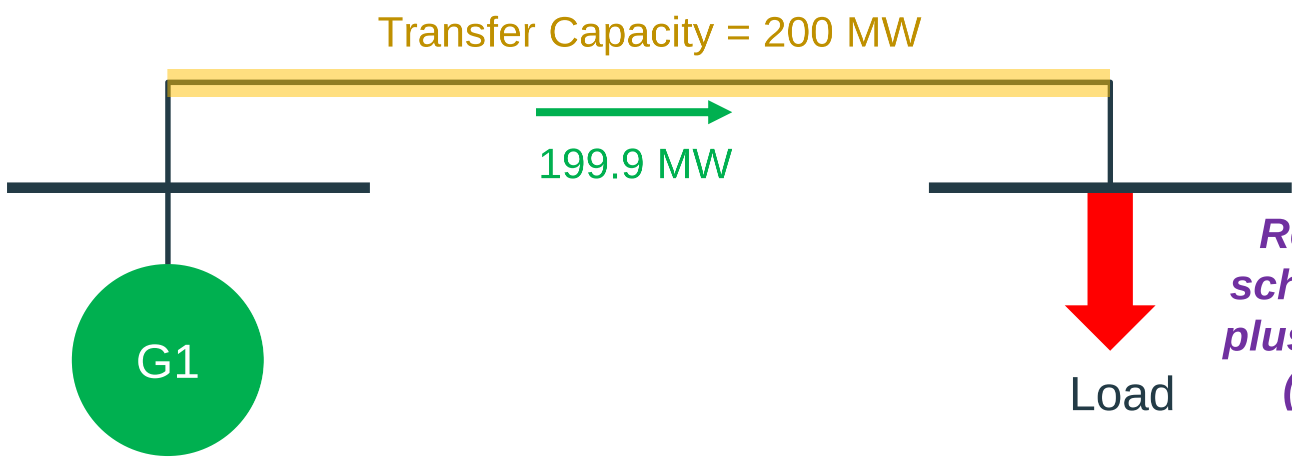


Offer: 300 MW @ P 3,000 / MWh	Demand: 250 MW
Schedule: 200 MW Price: P 3,000 / MWh	Schedule: 200 MW Price: P 800,000 / MWh

Load will be scheduled to curtail 50 MW and price will reflect VoLL CVC

MARKET PRICING RE-RUNS

Scheduling Run → Pricing Run



Reduce forecast by scheduled curtailment plus a very small value (50 MW + 0.1 MW = 50.1 MW)

Offer: 300 MW @ P 3,000 / MWh

Schedule: 199.9 MW
Price: P 3,000 / MWh

Final Schedule: 200 MW (scheduling run)
Final Price: P 3,000 / MWh (pricing run)

Demand: 250 MW → 199.9 MW

Schedule: 199.9 MW
Price: P 3,000 / MWh

Final Schedule: 200 MW (scheduling run)
Final Price: P 3,000 / MWh (pricing run)

MARKET PRICING RE-RUNS

Timeline

Current

In real-time

Prior to preliminary bill issuance (7 days after end of billing month)

18 days after end of billing month

Run RTD → Publish price with CVCs in MPI → Perform Manual Re-Run → *Issue Final Prices with Final Bills*

New Process

In real-time

Run RTD
- Scheduling run
- Pricing run

→ *Publish Final Prices in MPI*

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

SUMMARY OF ENHANCEMENTS TO THE PDM

- Market Dispatch Optimization Model
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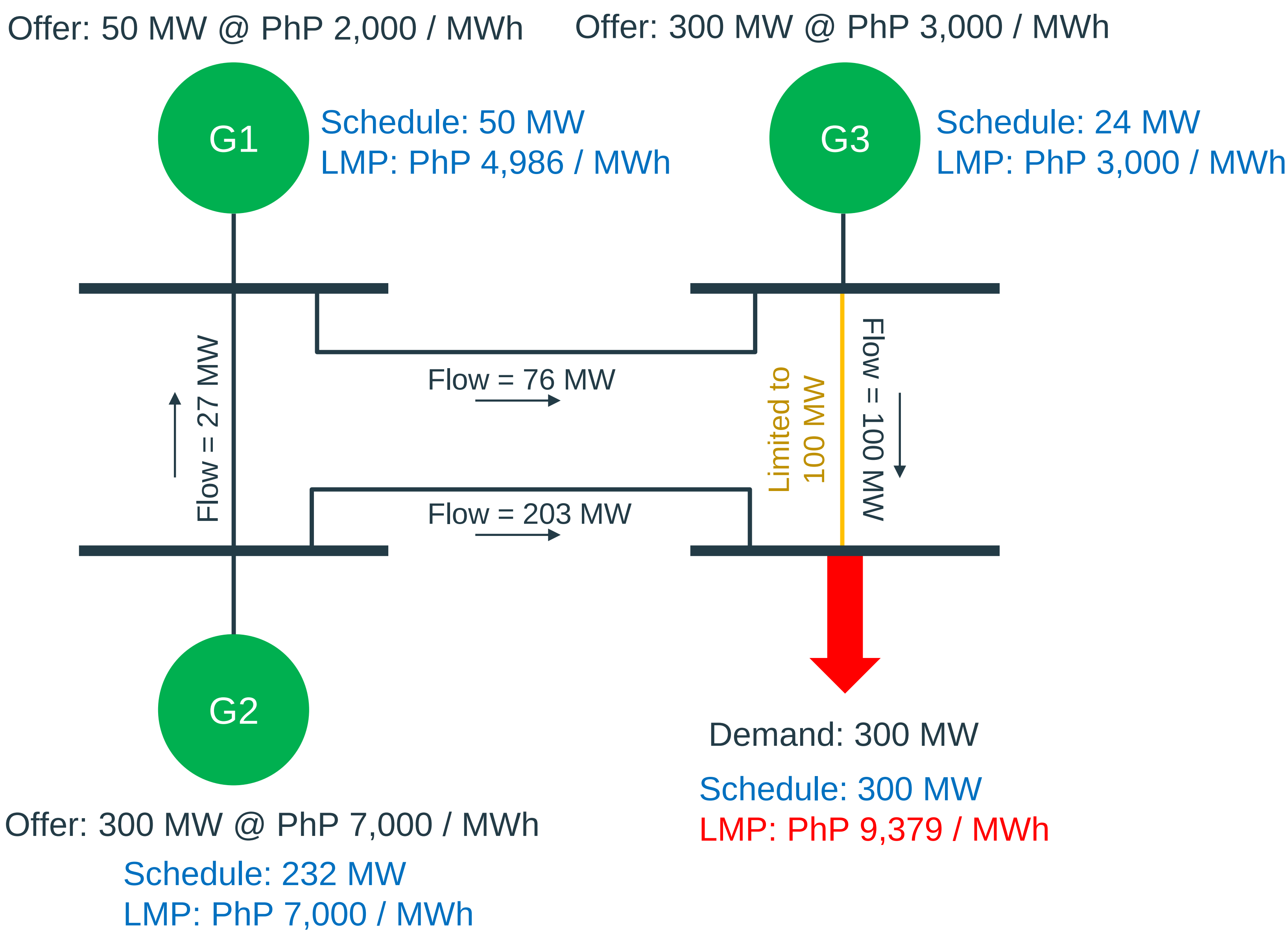
PRICE SUBSTITUTION METHODOLOGY (PSM)

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)

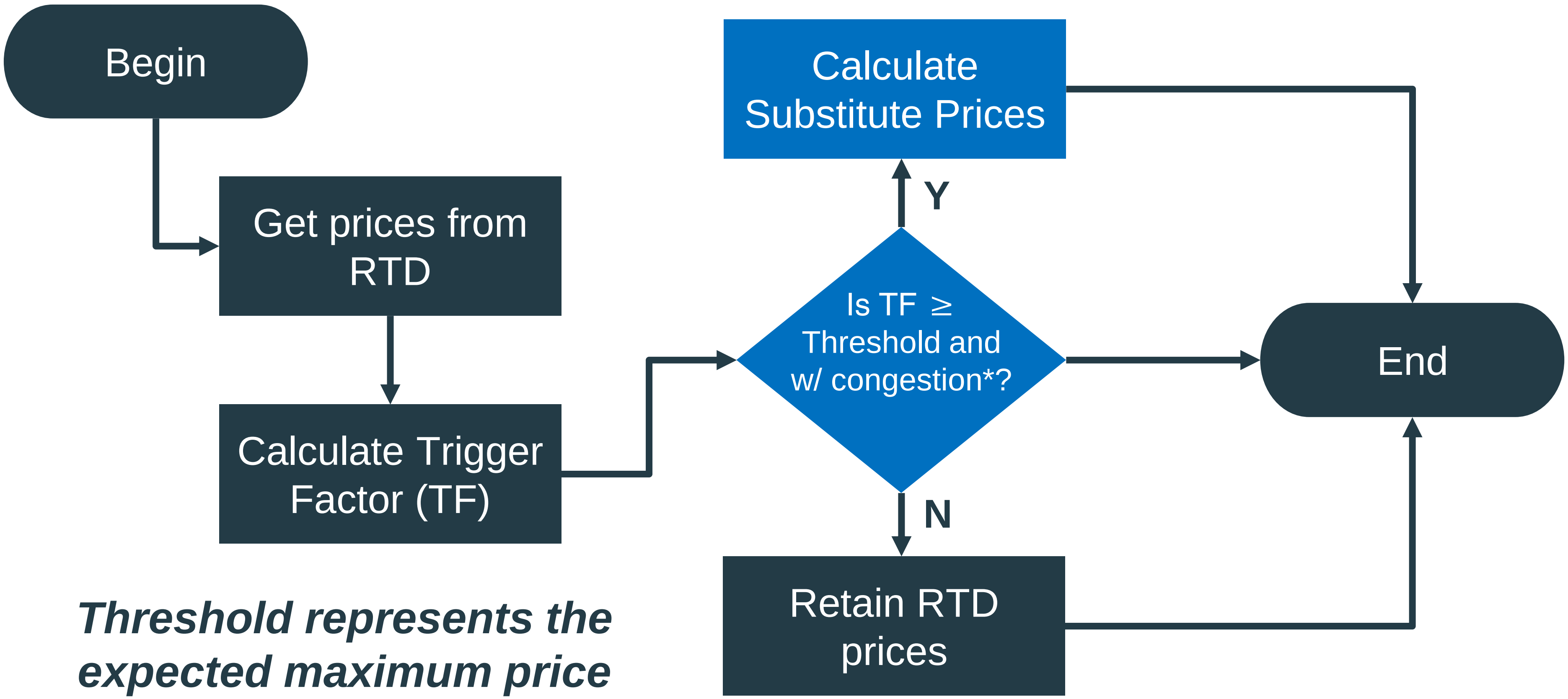
Example



PRICE SUBSTITUTION METHODOLOGY (PSM)

Overview

- When is PSM applied?



Threshold represents the expected maximum price spread from losses

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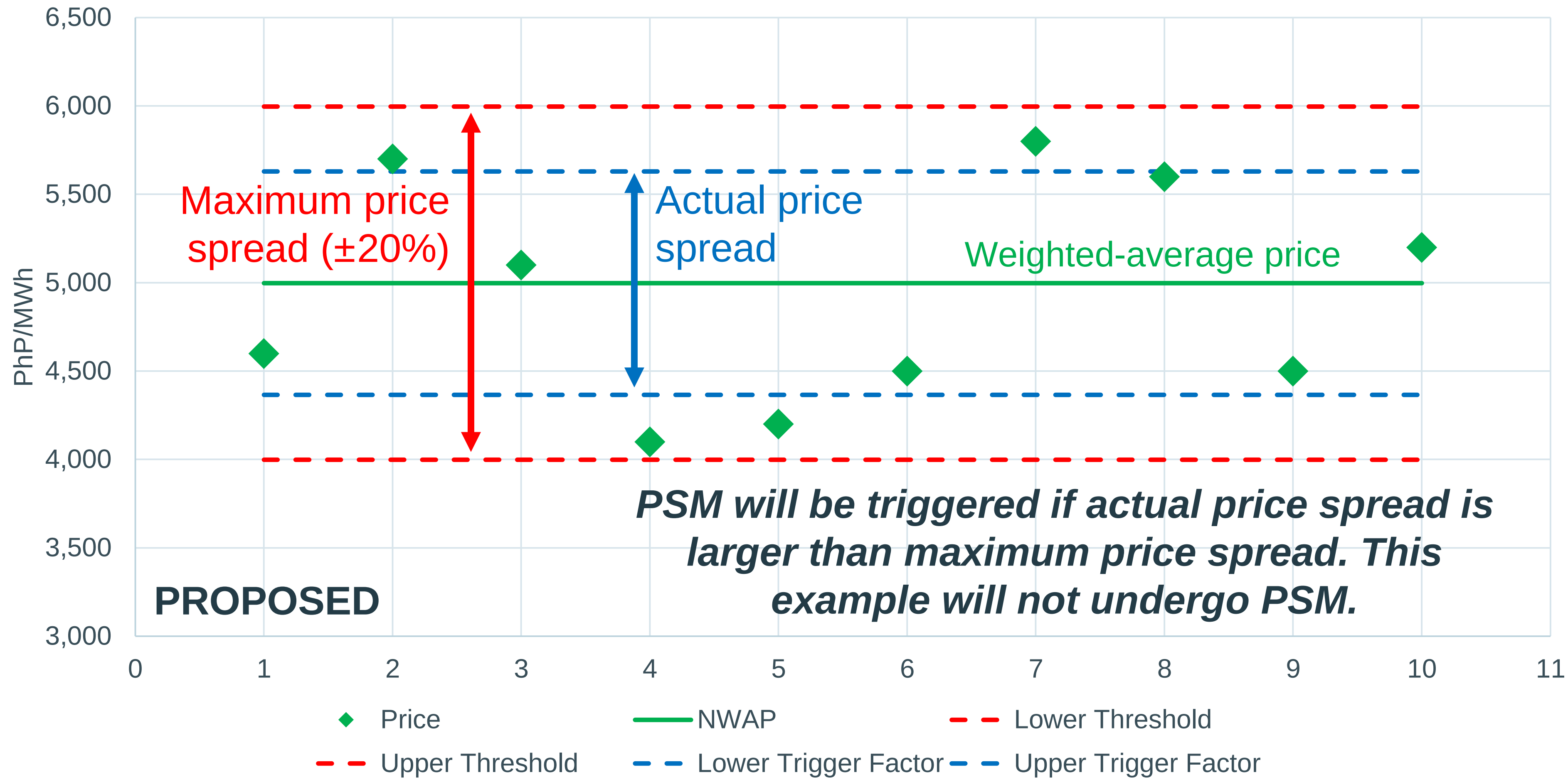
*PSM will only be triggered if there is congestion on network lines with loop flows

PRICE SUBSTITUTION METHODOLOGY

Trigger Factor



PRICE SUBSTITUTION METHODOLOGY (PSM)

Example

Offer: 50 MW @ PhP 2,000 / MWh

G1

Schedule: 50 MW
LMP: PhP 4,986 / MWh

Offer: 300 MW @ PhP 3,000 / MWh

G3

Schedule: 24 MW
LMP: PhP 3,000 / MWh

Step 1: Calculate NWAP

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

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

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

G2

Offer: 300 MW @ PhP 7,000 / MWh

Schedule: 232 MW
LMP: PhP 7,000 / MWh

Demand: 300 MW

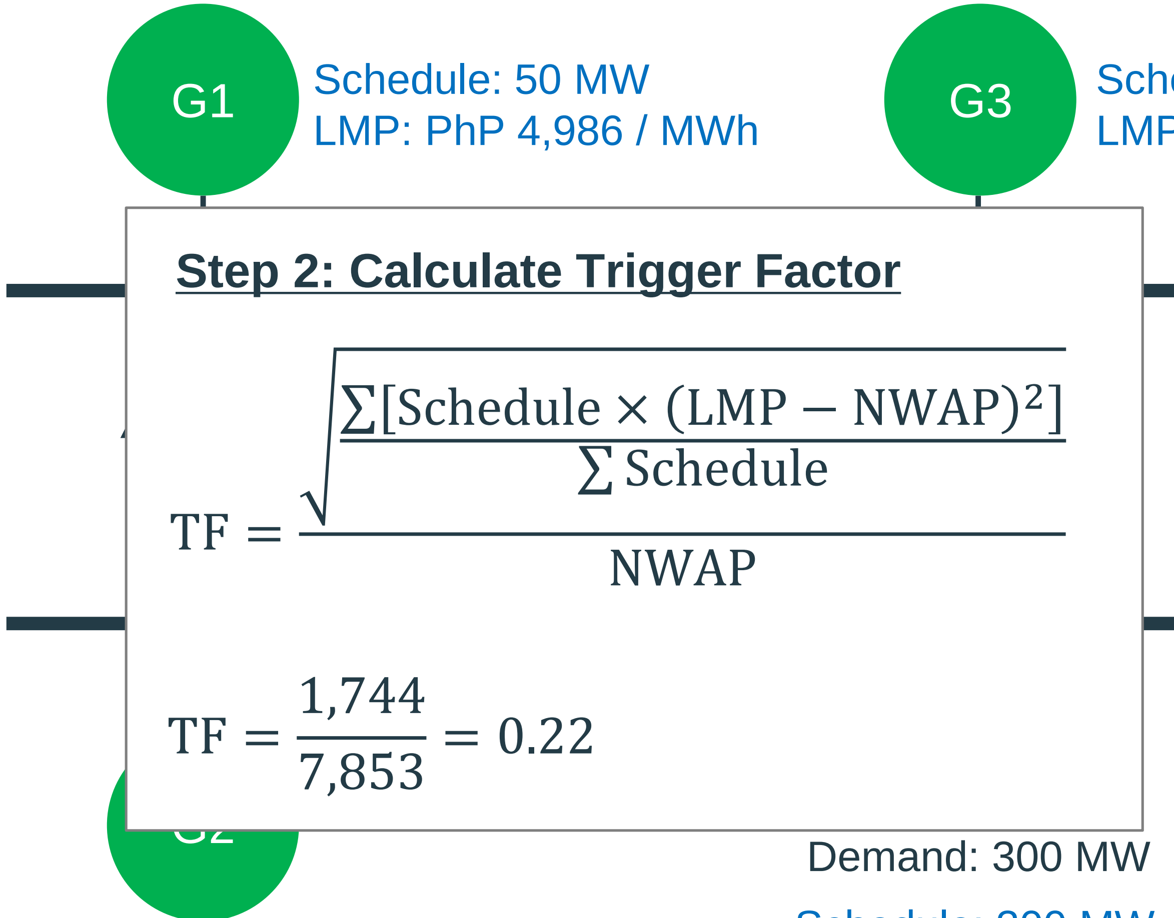
Schedule: 300 MW
LMP: PhP 9,379 / MWh

PRICE SUBSTITUTION METHODOLOGY (PSM)

Example

Offer: 50 MW @ PhP 2,000 / MWh

Offer: 300 MW @ PhP 3,000 / MWh



Schedule: 50 MW
LMP: PhP 4,986 / MWh

Schedule: 24 MW
LMP: PhP 3,000 / MWh

Step 2: Calculate Trigger Factor

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

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

Demand: 300 MW

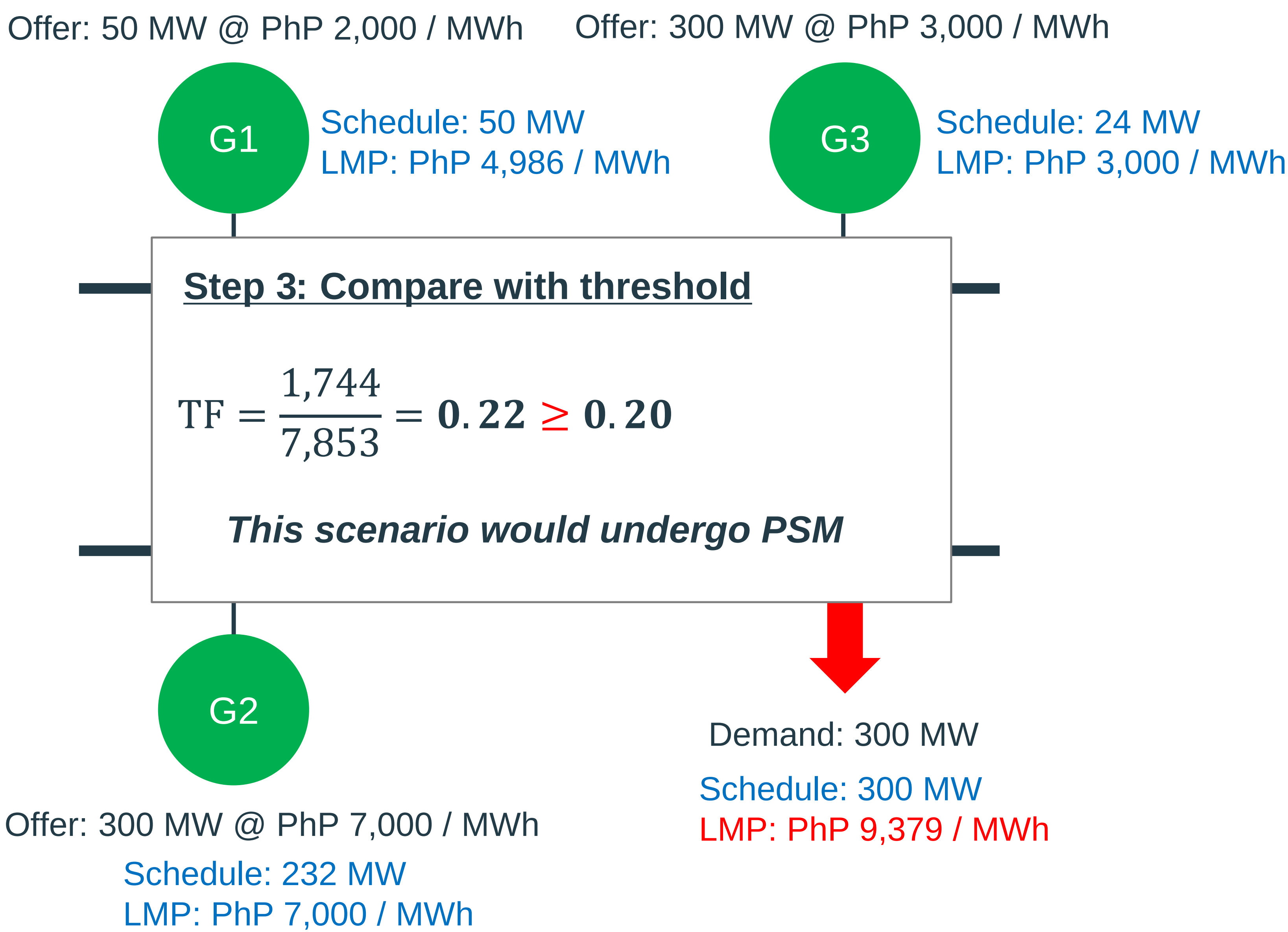
Schedule: 300 MW
LMP: PhP 9,379 / MWh

Offer: 300 MW @ PhP 7,000 / MWh

Schedule: 232 MW
LMP: PhP 7,000 / MWh

PRICE SUBSTITUTION METHODOLOGY (PSM)

Example



Step 3: Compare with threshold

$$\mathrm{TF} = \frac{1{,}744}{7{,}853} = \mathbf{0.22} \geq \mathbf{0.20}$$

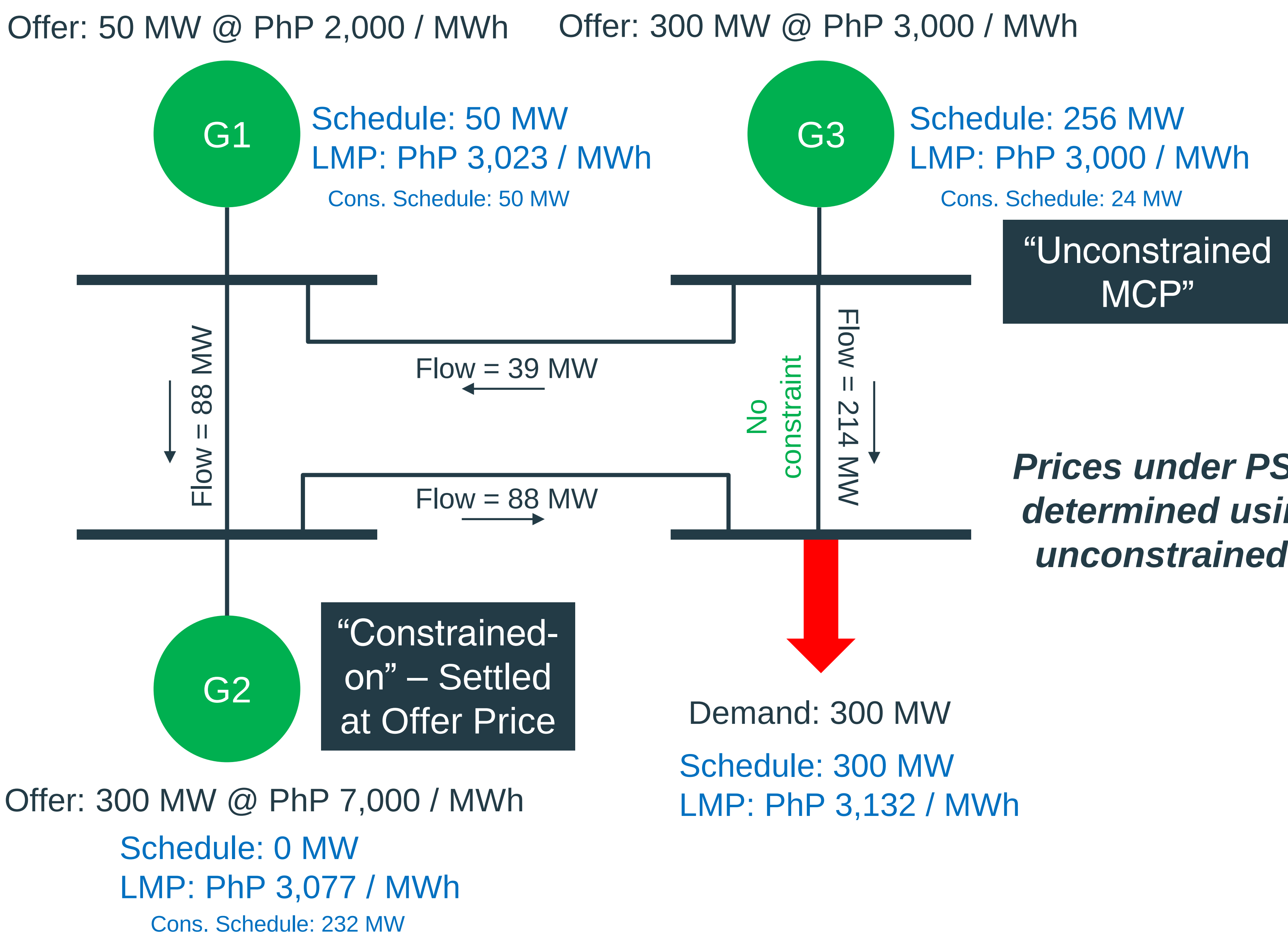
This scenario would undergo PSM

PRICE SUBSTITUTION METHODOLOGY (PSM)

Feature	Methodology
Pricing of Generators	Generators dispatched to address congestion (“Constrained-On Generators”) – Pay-as-Bid Other Generators – Unconstrained Market Clearing Price
Pricing of Customers	Single load price is computed in real-time based on the allocation of the estimated total generation cost based on schedule

PRICE SUBSTITUTION METHODOLOGY (PSM)

Example



Prices under PSM are determined using an unconstrained run.

PRICE SUBSTITUTION METHODOLOGY (PSM)

Example

Participant	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	?

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

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

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

PRICE SUBSTITUTION METHODOLOGY (PSM)

Example

Comparison of original and substitute prices:

Participant	Schedule (MW)	Original Price (PhP / MWh)	Substitute Energy Dispatch Price (PhP / MWh)
G1 (Unconstrained)	50	4,986	3,000
G2 (Constrained-on)	232	7,000	7,000
G3 (Unconstrained)	24	3,000	3,000
Load	300	9,379	6,153

PRICE SUBSTITUTION METHODOLOGY (PSM)

Timeline

Current

Run RTD → If PSM → 1 Day after: Publish Gen Prices → 7 days after end of billing month: Issue Customer Amounts with Prelim Bills → 18 days after end of billing month: *Issue Final Prices and Amounts with Final Bills*

New Process

Run RTD
- Scheduling run
- Pricing run

→ If PSM → In real-time: Calculate Generator and Customer Prices → In real-time: *Publish Final Prices in MPI*

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

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)

Generator Administered Price

	Su	Mo	Tu	We	Th	Fr	Sa
Week-4			Hour 09				
Week-3			Hour 09				
Week-2			Hour 09				
Week-1			Hour 09				
Week			Hour 09				

Administered price = Weighted-average of settlement prices

**Weighted using snapshot quantities*

Interval under suspension / intervention

ADMINISTERED PRICE (AP)

Generator Administered Price - Example

W	*Settlement Price* FEDP (PhP/MWh)	*Snapshot* SQ (MW)	FEDP× SQ
Week-4	5,670	15	85,050
Week-3	4,438	13	57,694
Week-2	4,149	11	45,639
Week-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)

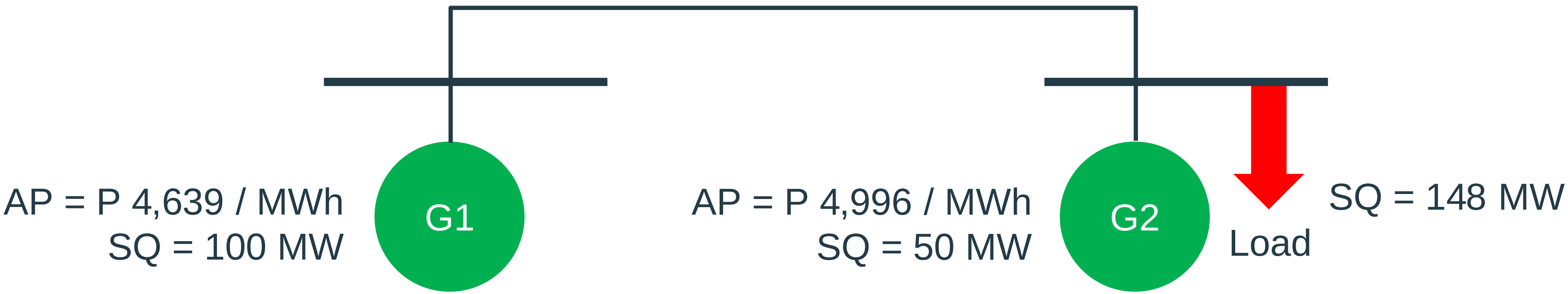
Load Administered Price

$$\text{Load Administered Price} = \frac{\text{Generation Cost}}{\text{Total Generation}}$$

$$\text{Load Administered Price} = \frac{\text{Total (Generator Administered Price} \times \text{Snapshot)}}{\text{Total Generation MW Snapshot}}$$

ADMINISTERED PRICE (AP)

Customer Administered Price - Example



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

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

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

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ADMINISTERED PRICE (AP)

Other features

Case	Methodology
Intervention / Suspension was declared and there is a newly modelled generator	Based on weighted-average price of other administered generators
Reserves	*Similar to energy administered price* 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.

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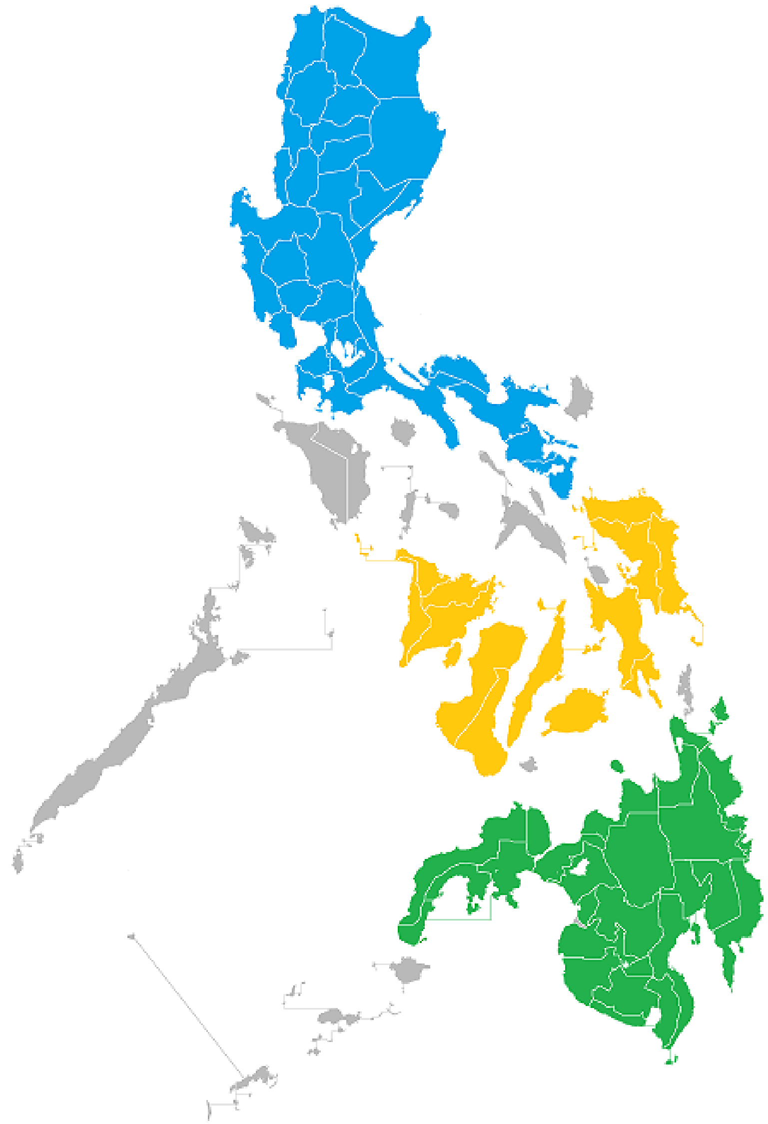
ADMINISTERED PRICE (AP)

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)

Timeline

Current

Run RTD

If AP →

7 days after end of billing month

Compute Generator Prices

→

7 days after end of billing month

Issue Customer Amounts with Prelim Bills

→

18 days after end of billing month

Issue Final Prices and Amounts with Final Bills

New Process

Run RTD
- Scheduling run
- Pricing run

If AP →

In real-time

Calculate Generator and Customer Prices

→

In real-time

Publish Final Prices in MPI

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:
  - System Voltage Requirement
  - Thermal Limits
  - 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

- Market price (price taker)
- If necessary, additional compensation to cover variable costs

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

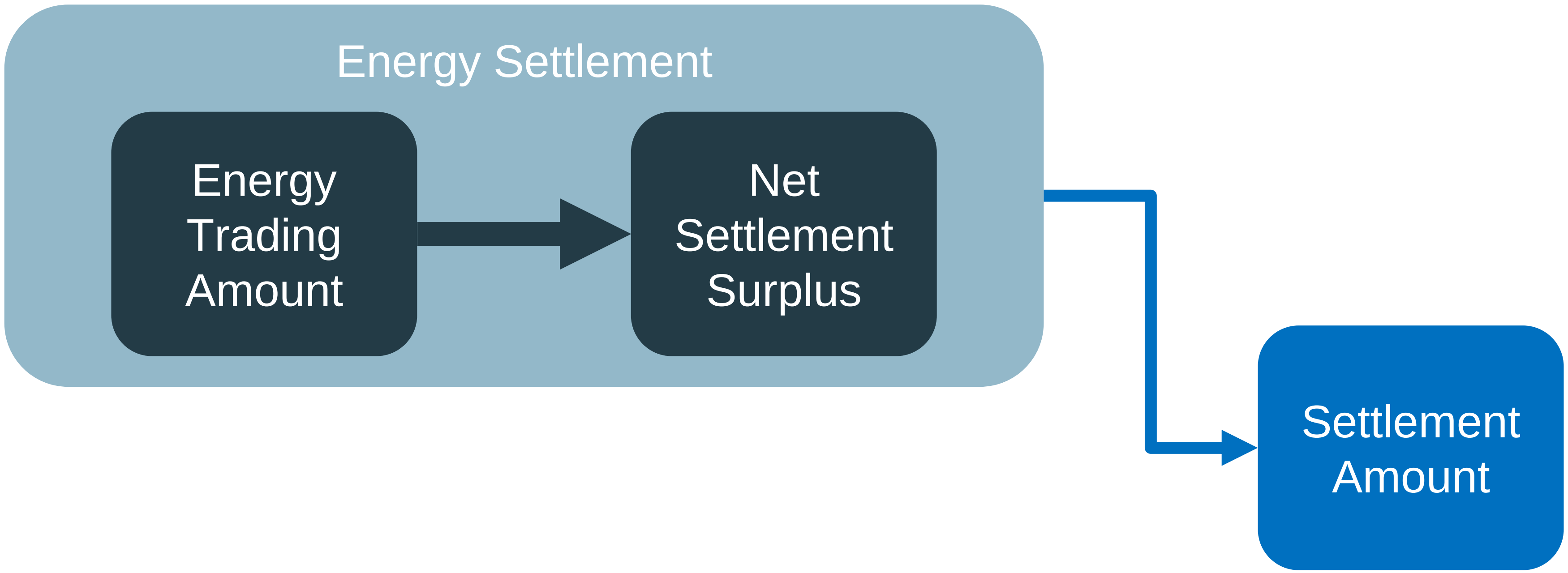
Final Energy Dispatch Price (FEDP)

Normal conditions / CVC prices	Extreme nodal price separation	Rolling average of 7 days is equal or greater than P9/kWh	Market Intervention or Market Suspension
Manual / Automatic Pricing Run & Real Time Dispatch (RTD)	**Price Substitution Methodology (PSM)**	**Secondary Price Cap (SEC)**	**Administered Price (AP)**

Hierarchy of Prices

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)

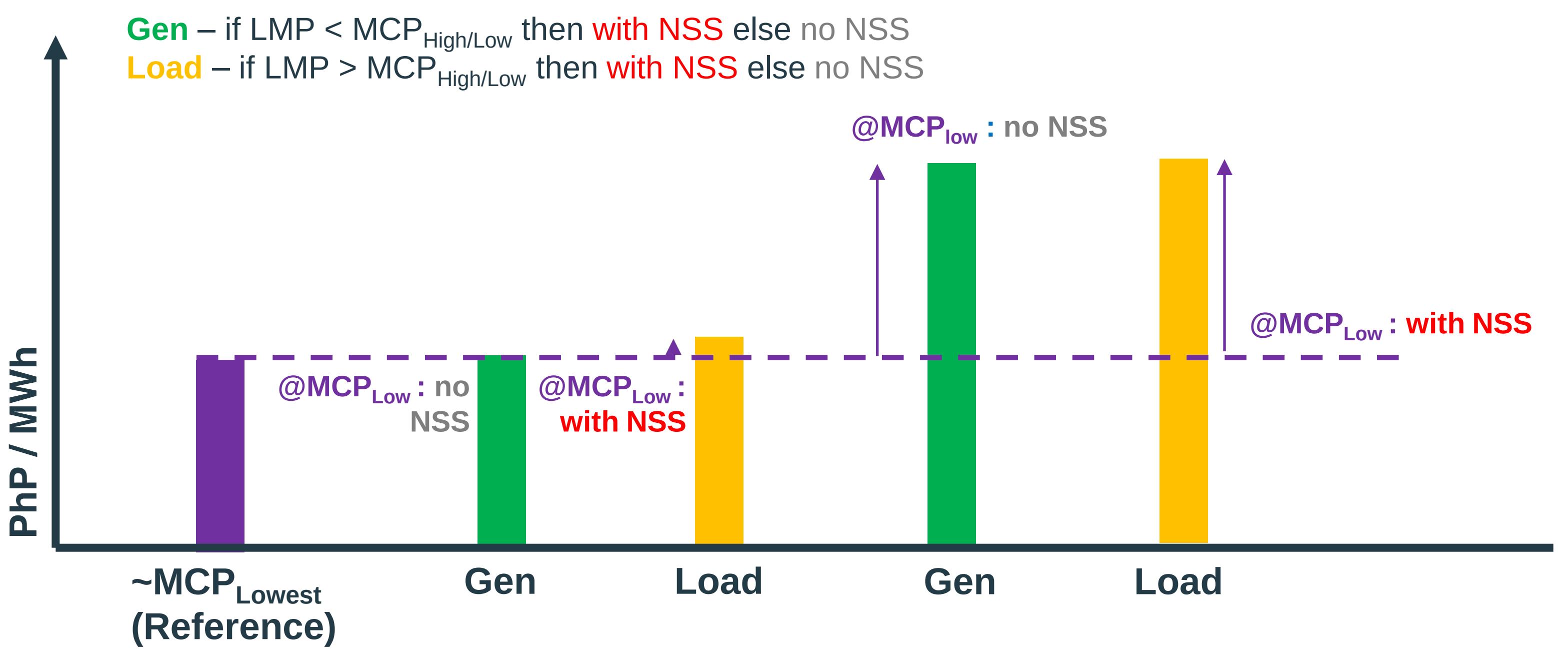
PART	MQ [A]	BCQ [B]	FEDP [C]	FEDP@RefNode [D]	ETA [A×C – B×D]
G1	252	150	3,000	3,000	**306,300**
G2	103	50	5,000	5,102	**259,924**
L1	(150)	(150)	3,046	3,000	**(6,827)**
L2	(200)	(50)	5,102	5,102	**(765,230)**
				NET	**(205,833)**

Net Settlement Surplus

SETTLEMENT CALCULATIONS

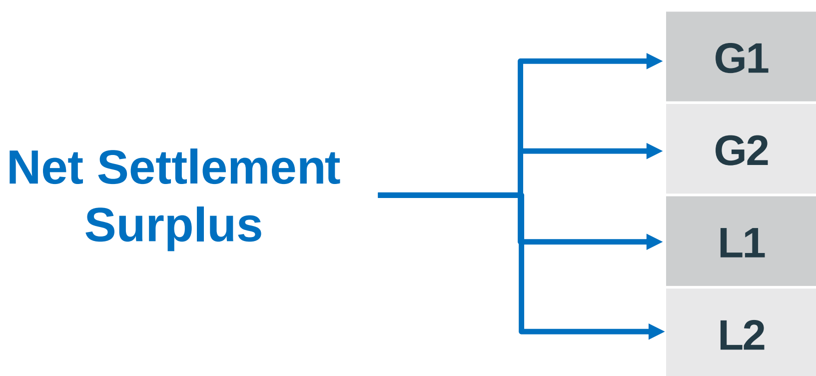
Enhanced – Net Settlement Surplus

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

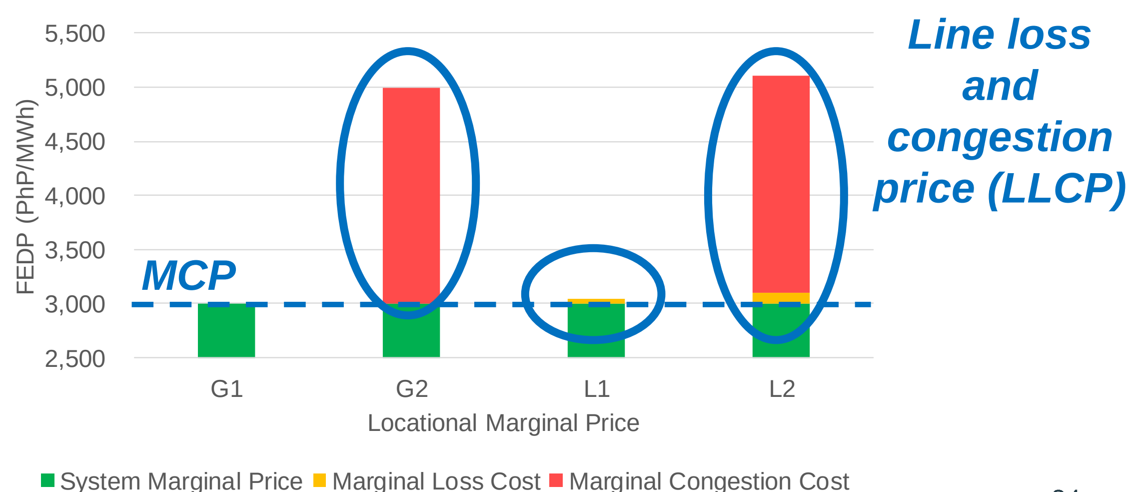


SETTLEMENT CALCULATIONS

Enhanced – Net Settlement Surplus



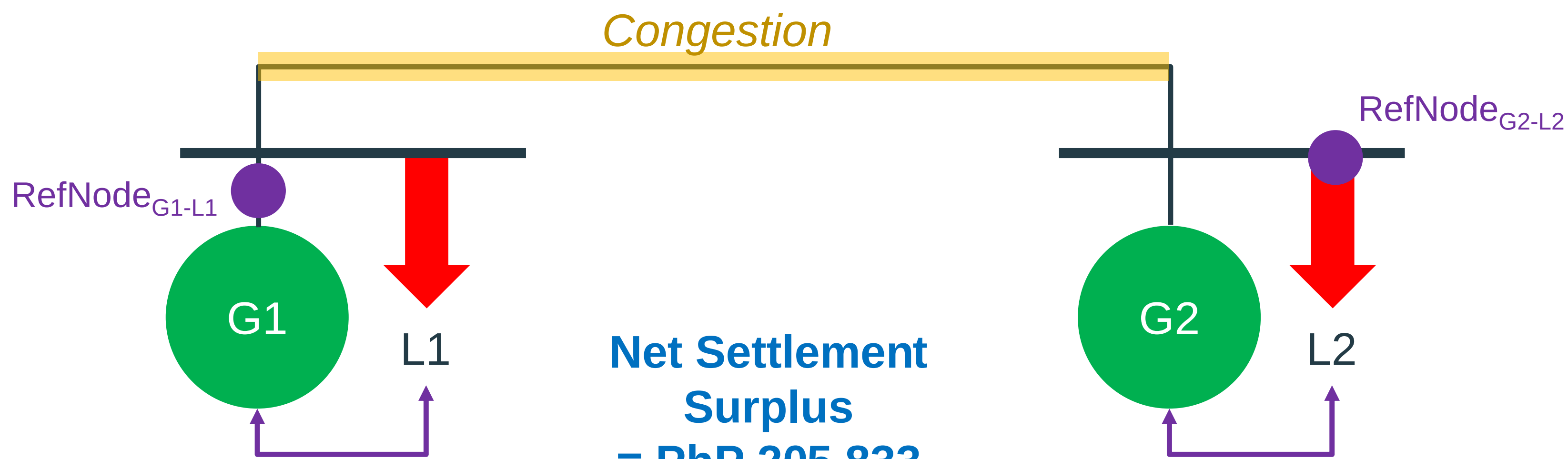
$$\text{LLCC} = \text{MQ} \times \text{LLCP} - \text{BCQ} \times \text{LLCP}_{@\text{RefNode}}$$



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

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**

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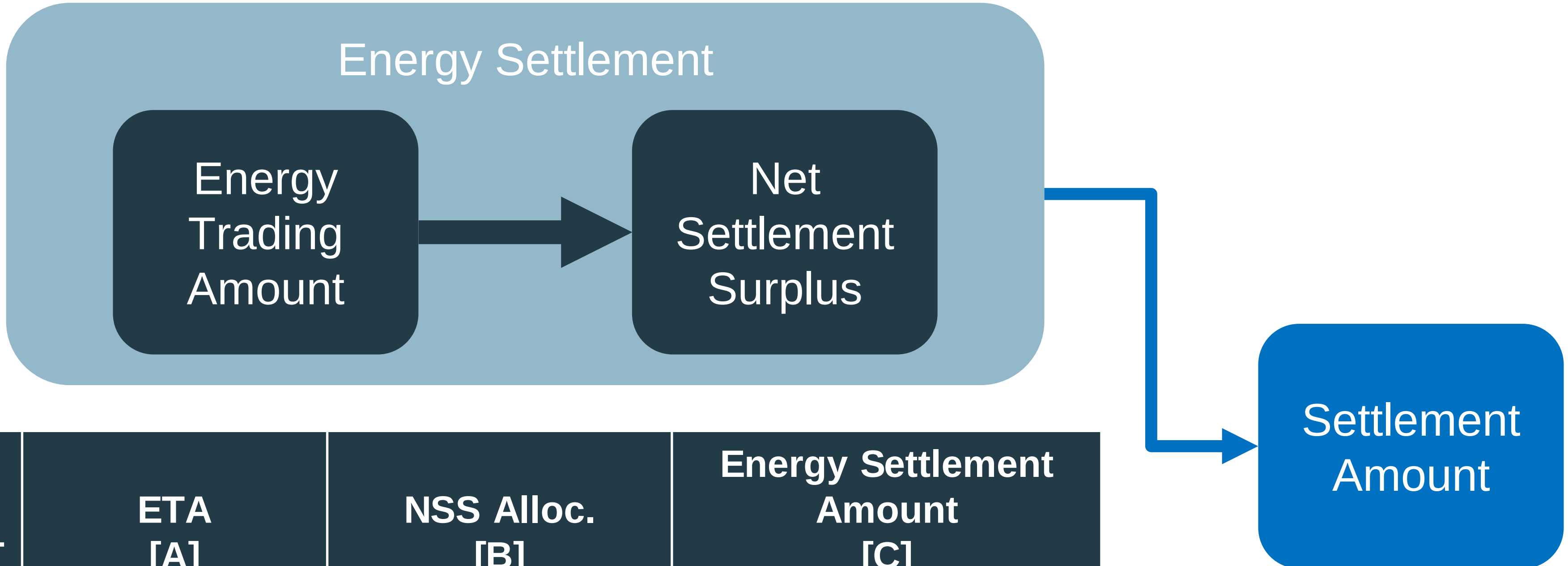
NSS is allocated to participants with actual payments for congestion

*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

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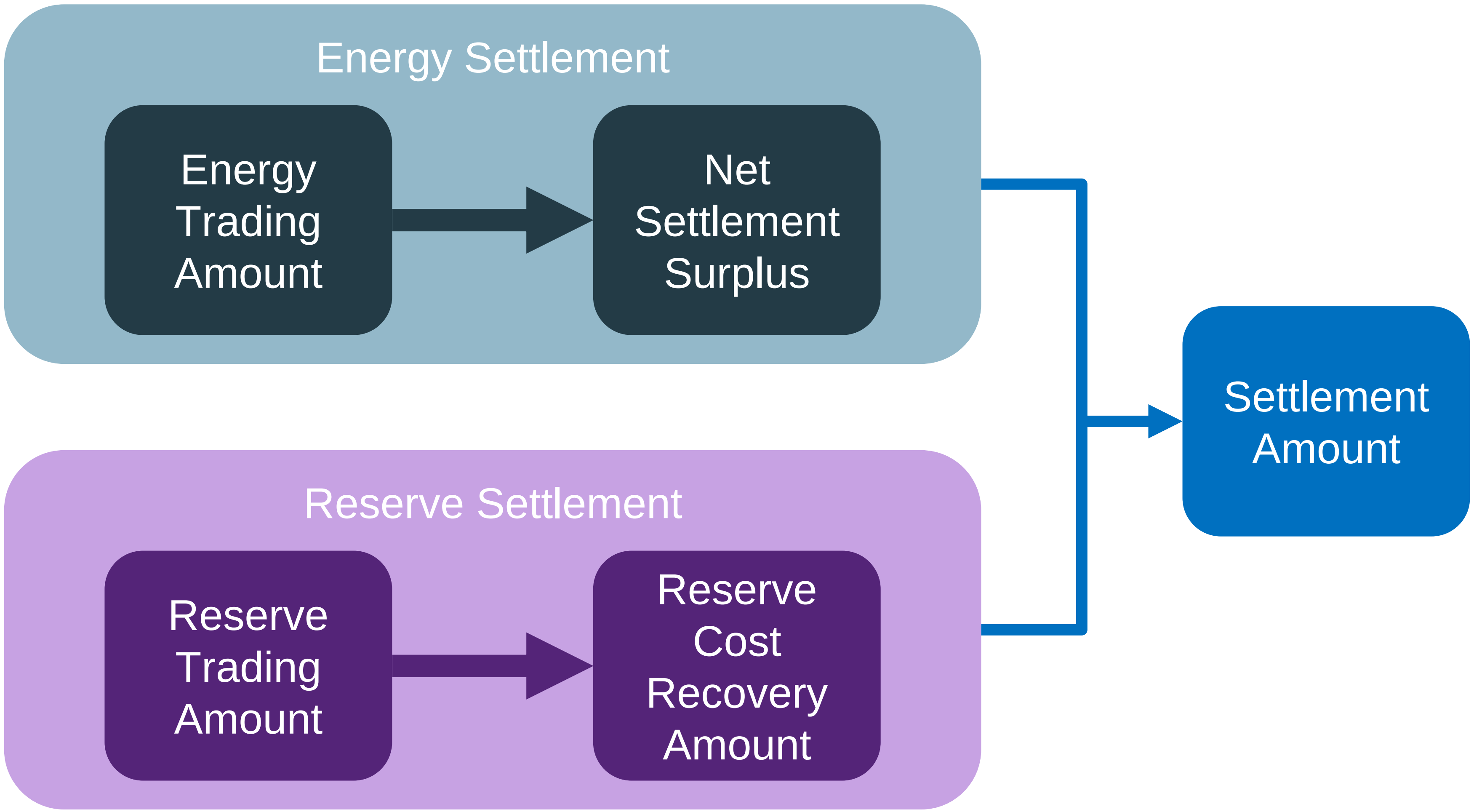
WHOLESALE ELECTRICTY SPOT MARKET POWERING PROGRESS 2006 - 2016

SETTLEMENT CALCULATIONS

Enhanced



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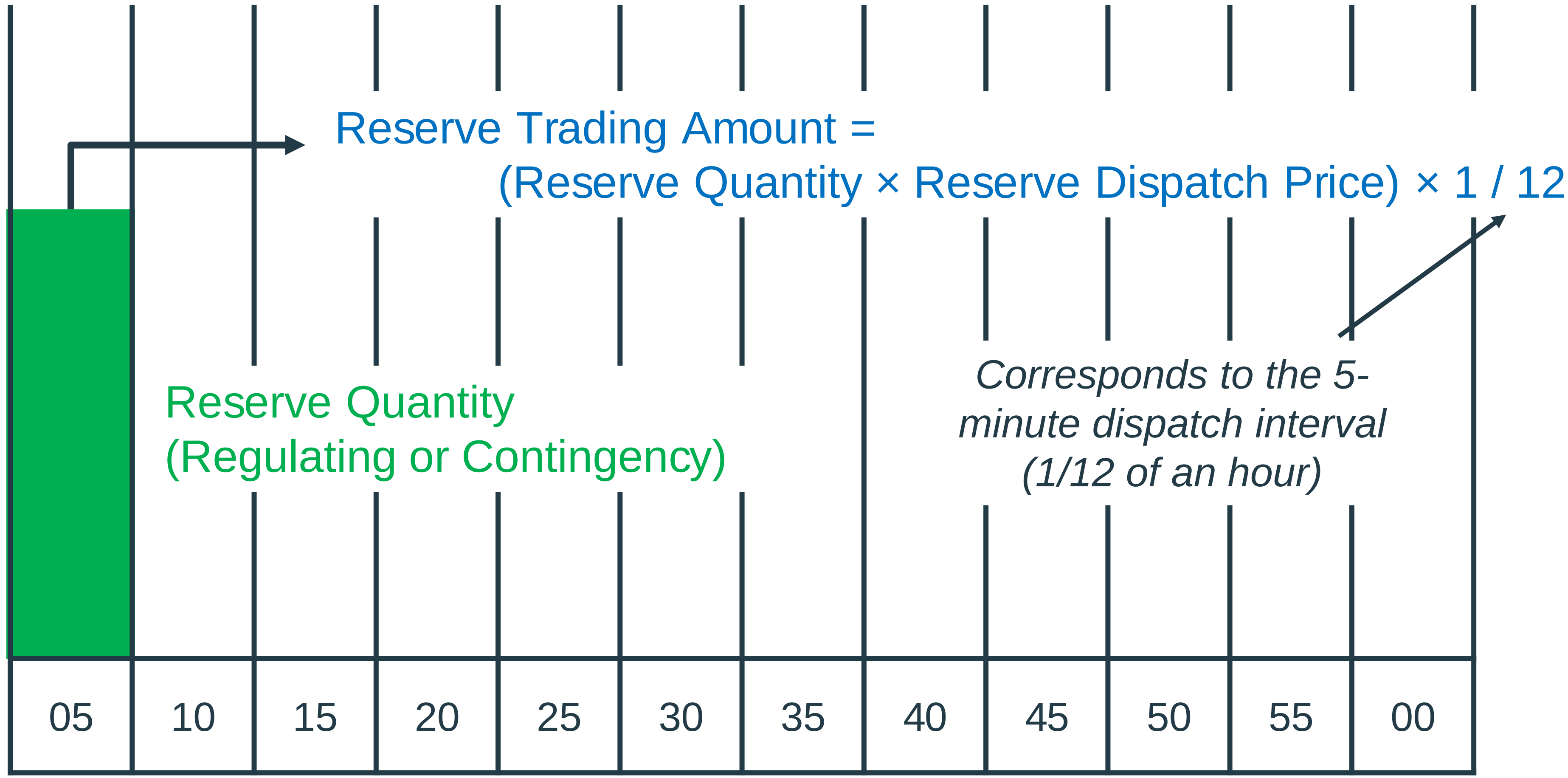
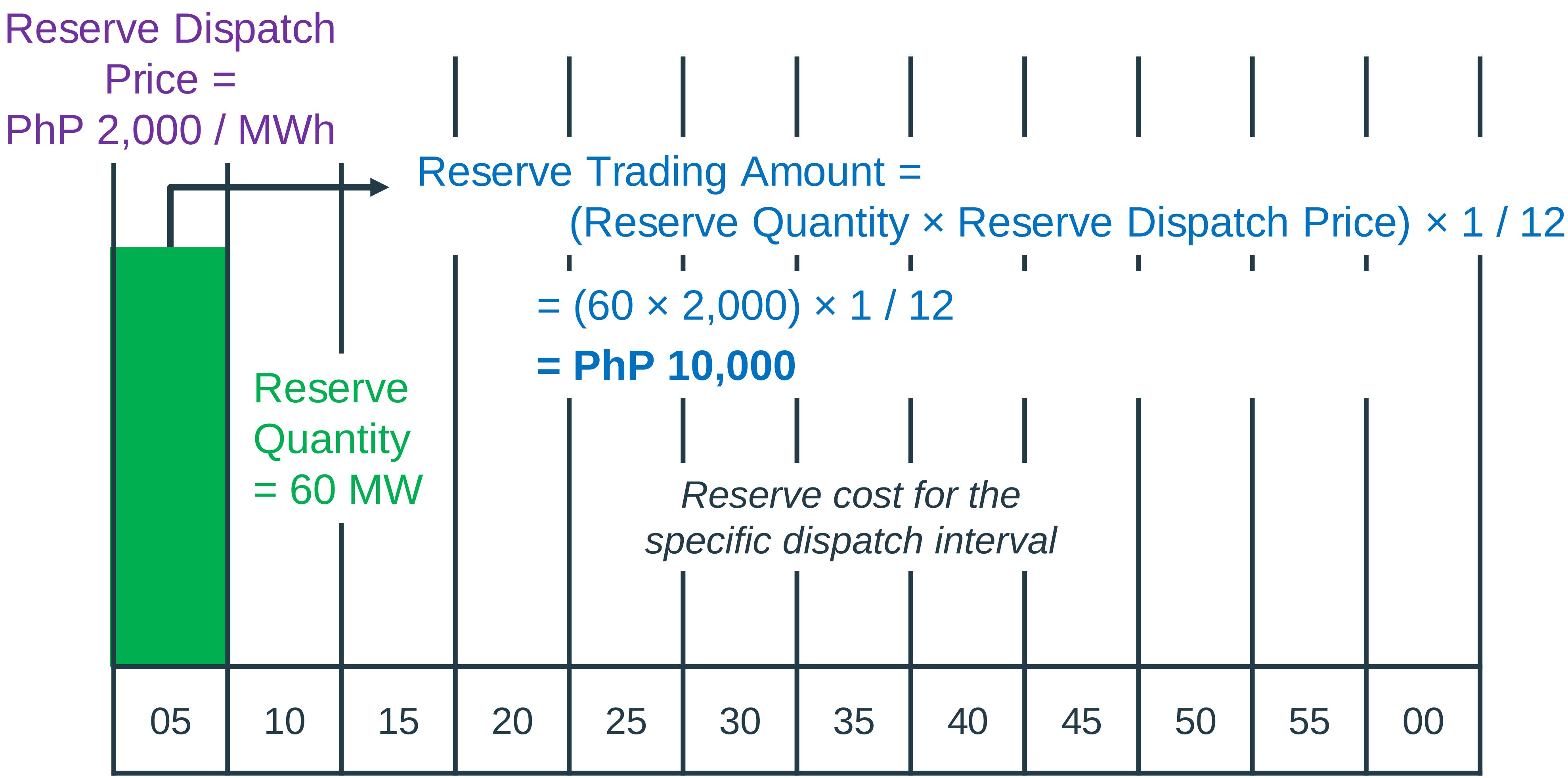
SETTLEMENT CALCULATIONS

Enhanced – Reserve Trading Amount



SETTLEMENT CALCULATIONS

Enhanced – Reserve Trading Amount (example)



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SETTLEMENT CALCULATIONS

Enhanced – Reserve Cost Recovery

Reserve Type	Reserve Sub-Type	Cost Recovery Model
Regulation	Raise	Pro-rate to all based on MQ*
	Lower	Pro-rate to all based on MQ*
Contingency	Raise	Runway model
	Lower	Pro-rate to loads based on MQ*

*MQ – metered quantity

SETTLEMENT CALCULATIONS

Enhanced – Reserve Cost Recovery (example)

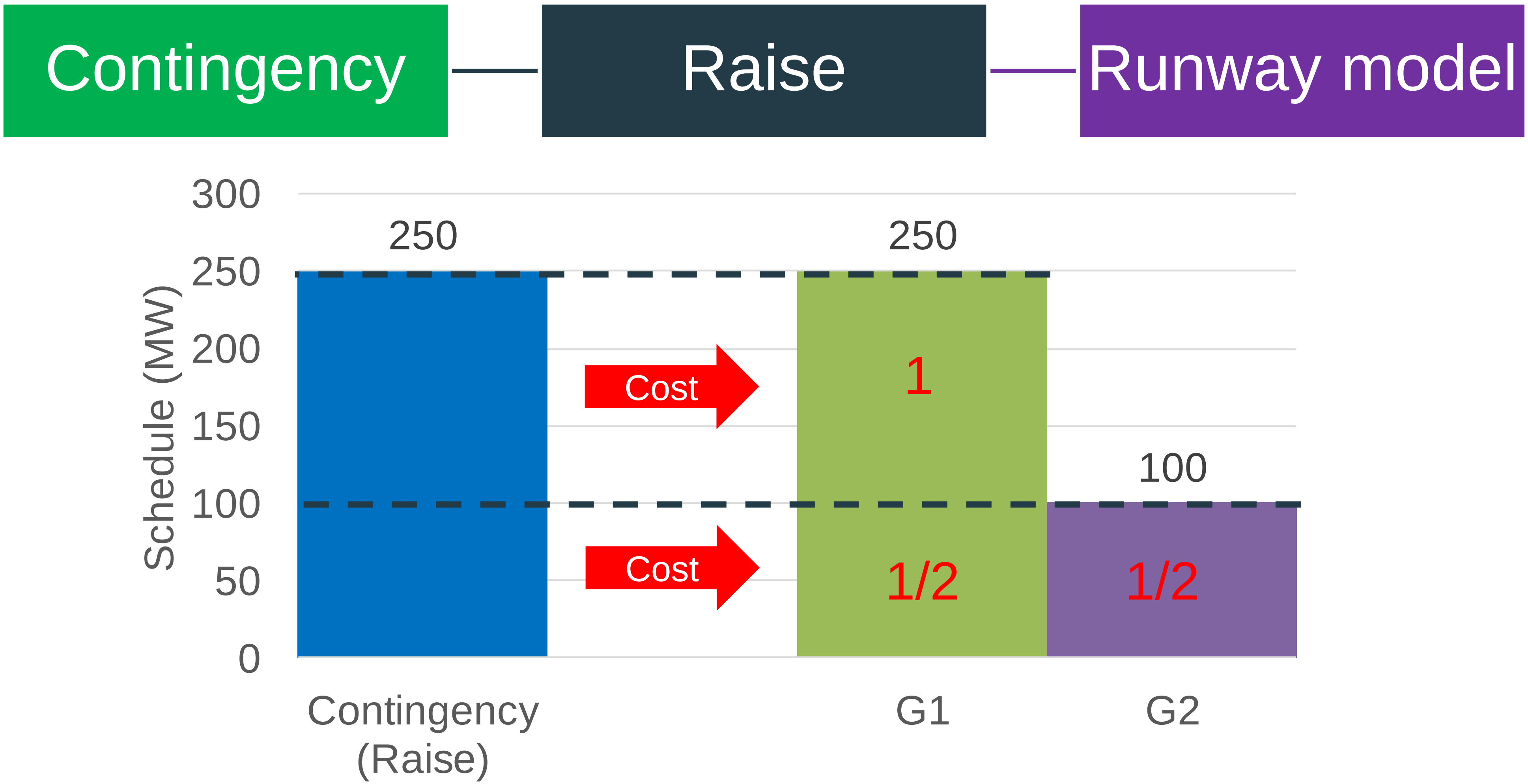
Regulation
- Raise — Pro-rate to all based on MQ*
- Lower — Pro-rate to all based on MQ*

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

	Metered Quantity, MQ (MWh)	Cost Recovery Amount (PhP) $\frac{\text{MQ}}{\text{TOTAL MQ}} \times \text{RR COST}$
G1	252	(10,726)
G2	103	(4,382)
L1	150	(6,382)
L2	20	(8,509)
TOT	**705**	**(30,000)**

SETTLEMENT CALCULATIONS

Enhanced – Reserve Cost Recovery (example)



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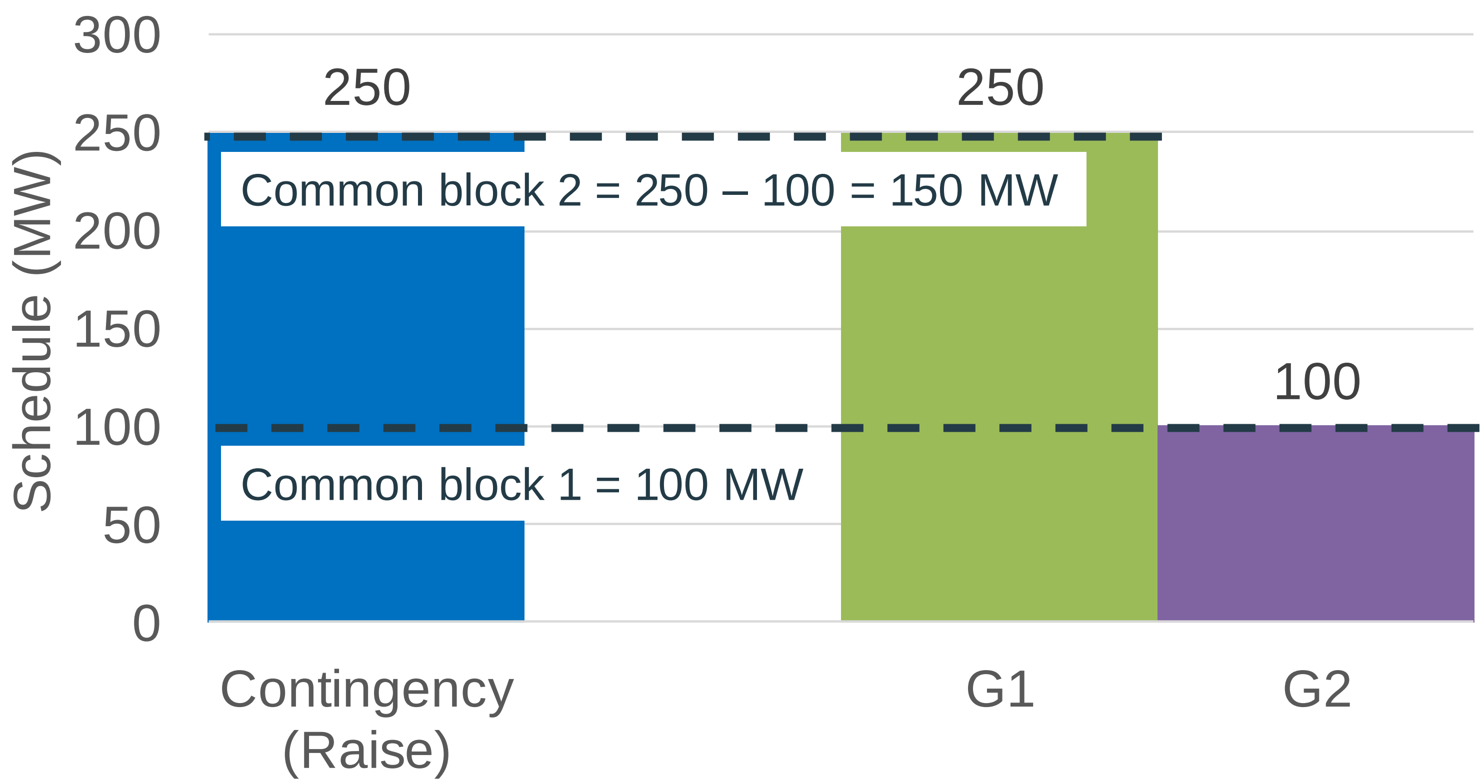
SETTLEMENT CALCULATIONS

Enhanced – Reserve Cost Recovery (example)

Contingency — Raise — Runway model



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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 × 2,500 × 1 / 12 = PhP 20,833

$RCRA_{CB1}$ = 20,833 × 1 / 2 = PhP 10,417

For common block 2 (150 MW),

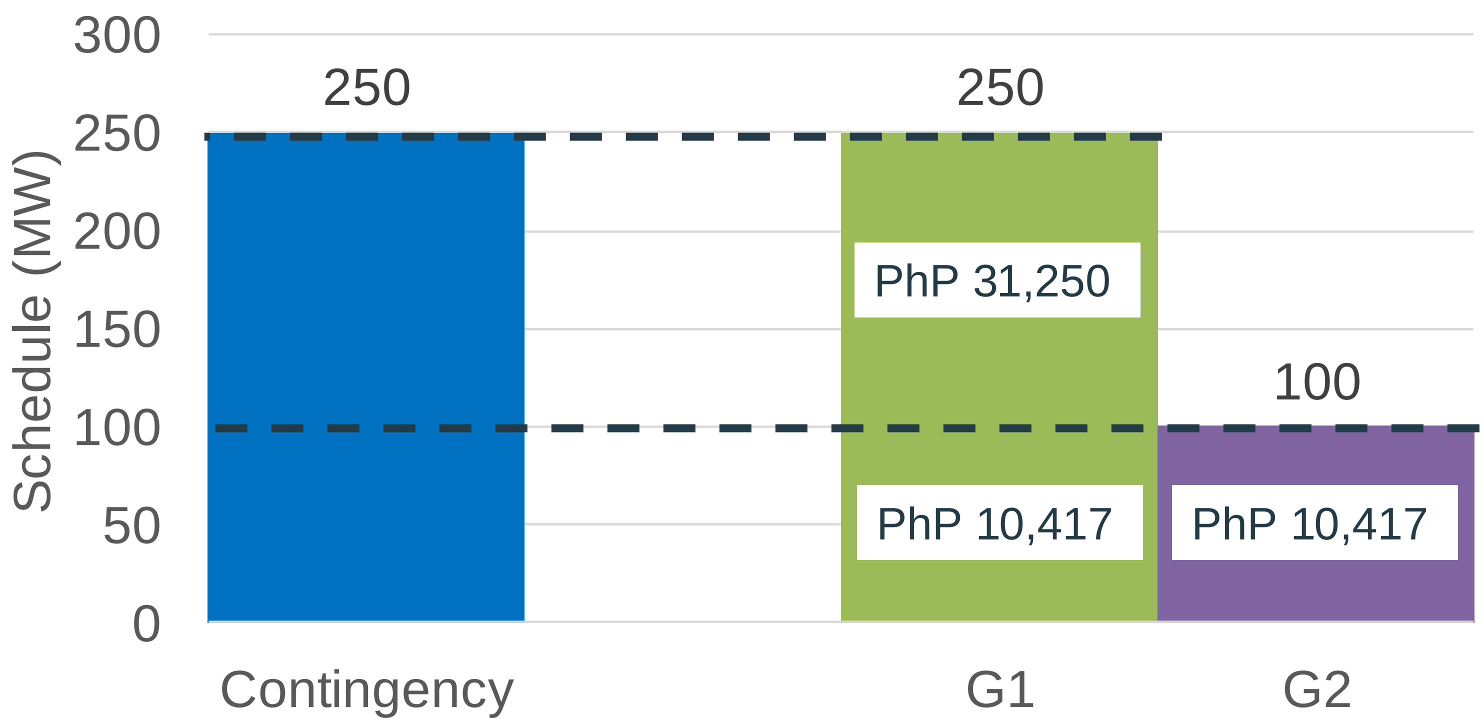
RTA_{CB2} = 150 × 2,500 × 1 / 12 = PhP 31,250

$RCRA_{CB2}$ = 31,250 × 1 = PhP 31,250

SETTLEMENT CALCULATIONS

Enhanced – Reserve Cost Recovery (example)

Contingency — Raise — Runway model



Cost Recovery = Amount	PhP 41,667	PhP 10,417

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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) $\frac{\text{CUS MQ}}{\text{TOTAL CUS MQ}} \times \text{CL COST}$
G1	252	N/A
G2	103	N/A
L1	150	(8,571)
L2	20	(11,429)
TOT	**705**	**(20,000)**

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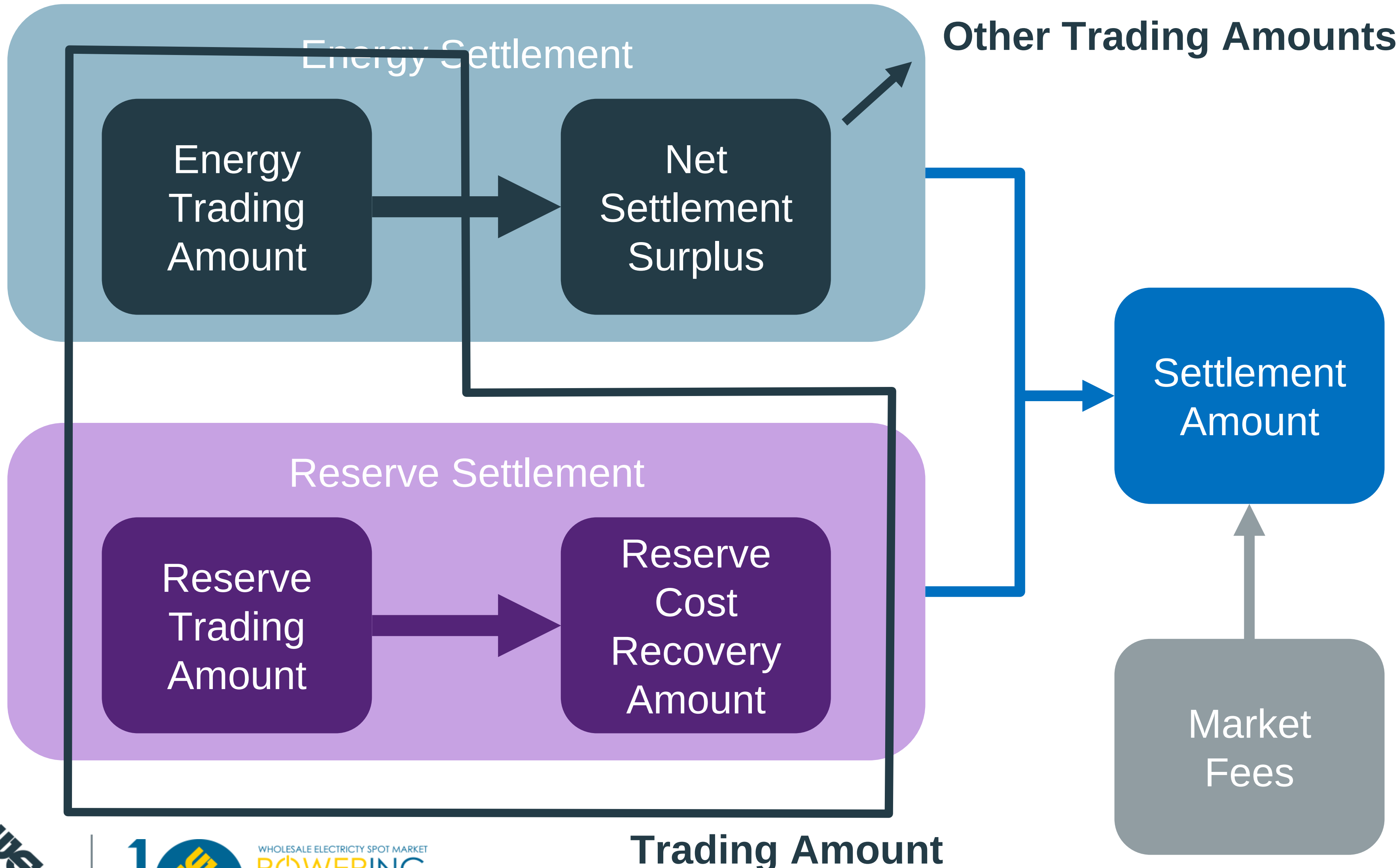
SETTLEMENT AMOUNT

Enhanced WESM Design



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WHOLESALE ELECTRICITY SPOT MARKET POWERING PROGRESS 2006 - 2016

SETTLEMENT AMOUNT

Enhanced WESM Design

Settlement Amount

= Trading Amounts +

Other Trading Amounts –

Market Fees

SUMMARY

SUMMARY

FEATURE	DESCRIPTION
Dispatch Interval	5 minutes
Pricing	Ex-ante only
Market Re-runs	Automatic pricing re-runs
Consideration of Pmin	Submitted as offer
Scheduling/ Trading of Energy and Reserves	Co-optimized energy and reserves
Settlements	5-minute metered quantity multiplied by price
Administered Prices	Based on historical prices
PSM Settlement	Based on unconstrained prices
MRU Settlement	Market price plus additional compensation

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Market Corporation

DAGHANG SALAMAT

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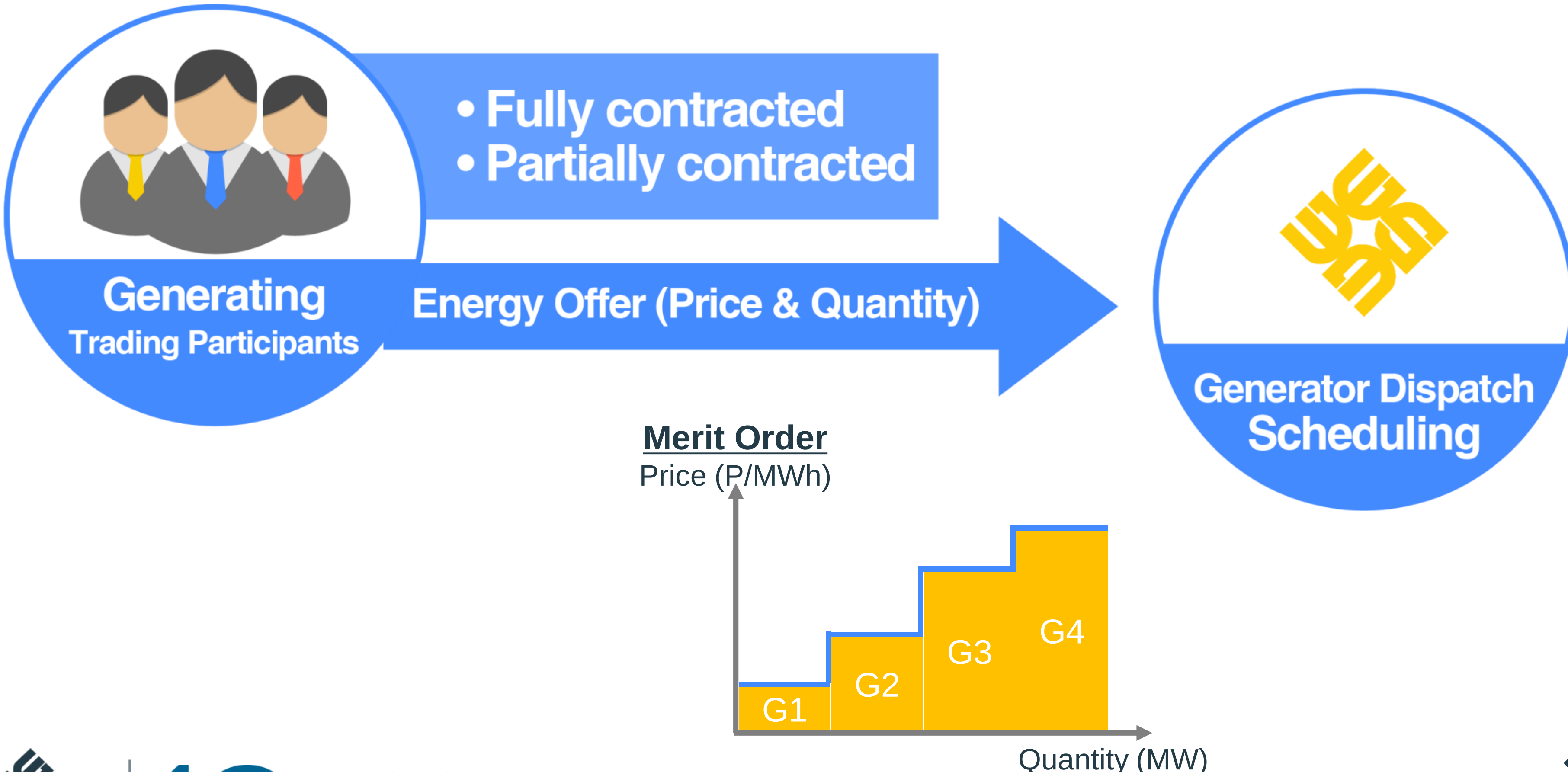
GUIDING PRINCIPLES

Gross pool

- All energy is scheduled 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

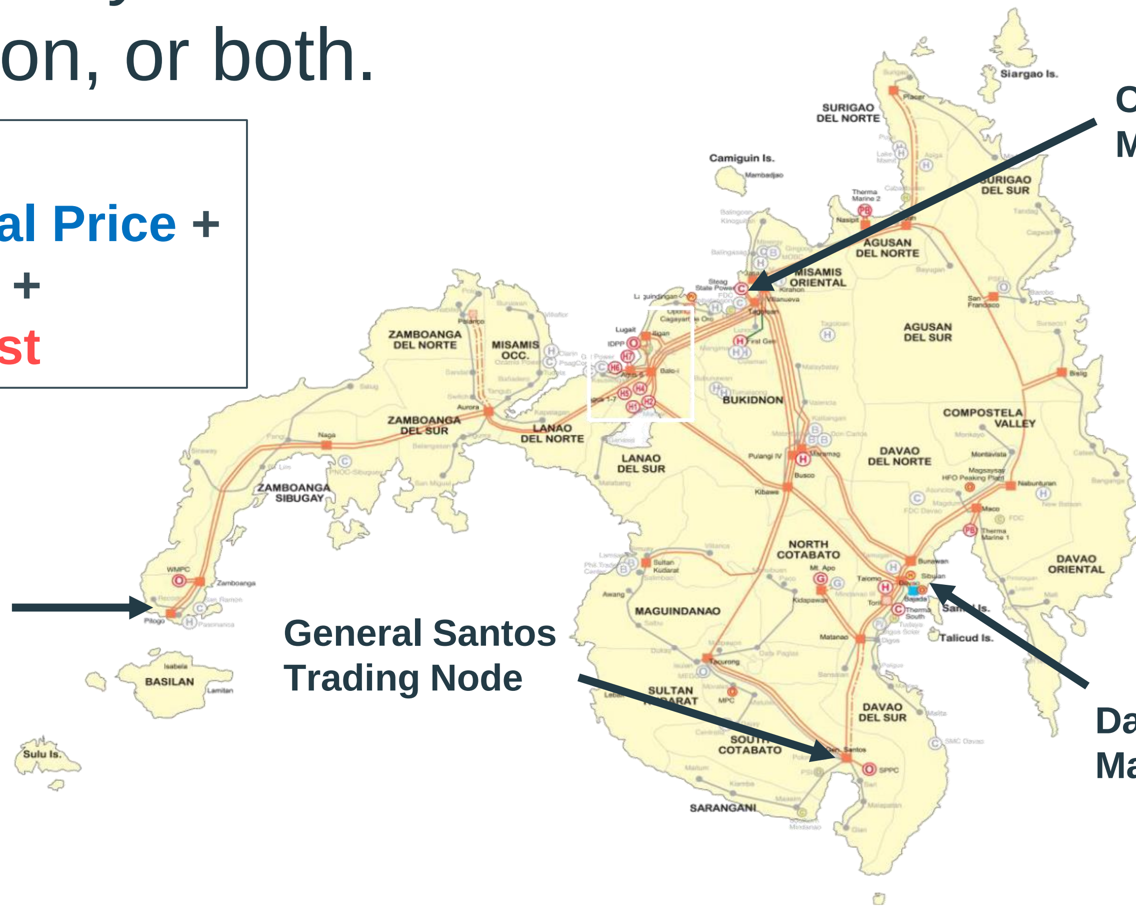


Image source: Transmission Development Plan 2014-2015 of the National Grid Corporation of the Philippines (NGCP)

GUIDING PRINCIPLES

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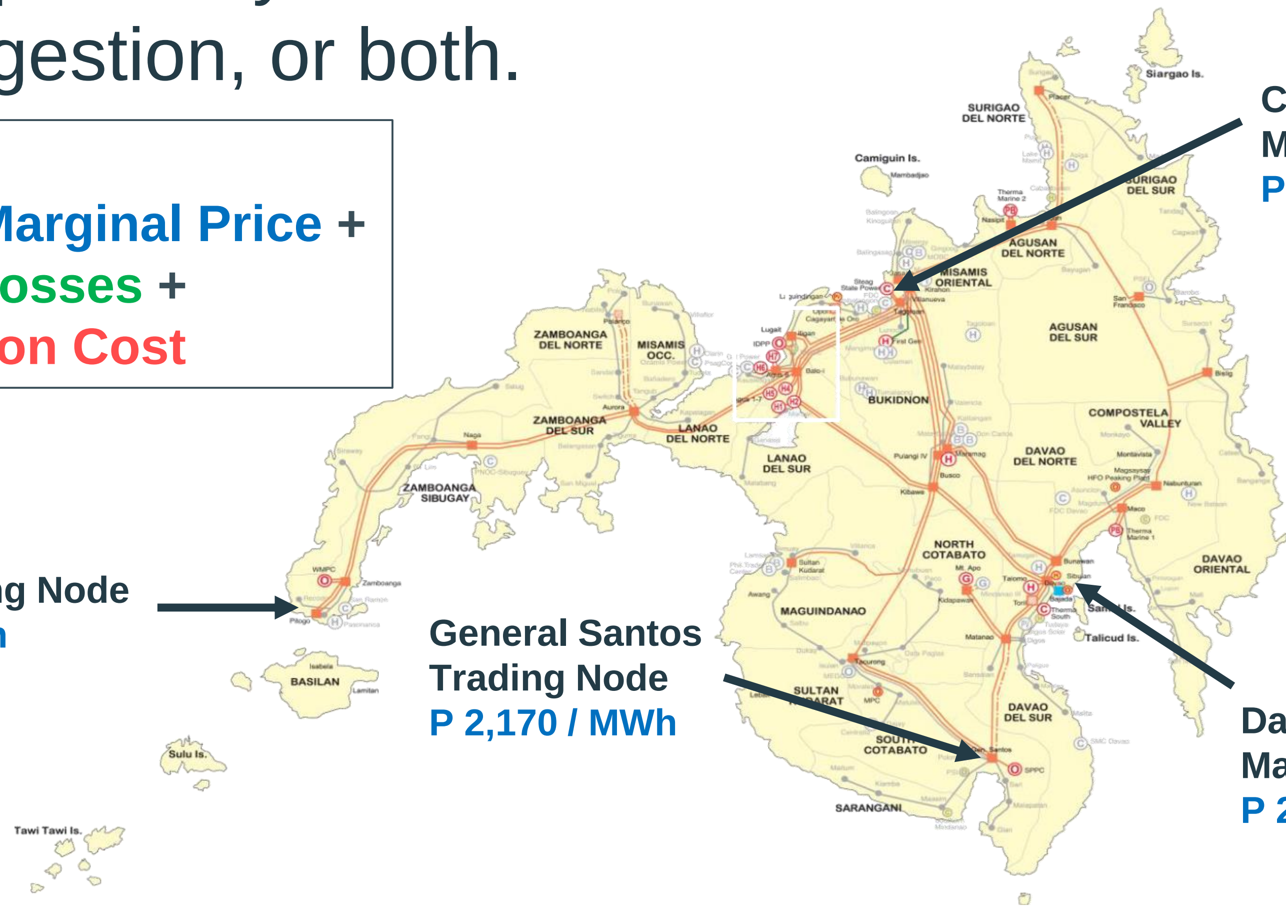

Cagayan de Oro City Market Trading Node
P 2,170 / MWh

Zamboanga Market Trading Node
P 2,170 / MWh

General Santos Trading Node
P 2,170 / MWh

Davao Market Trading Node
P 2,170 / MWh

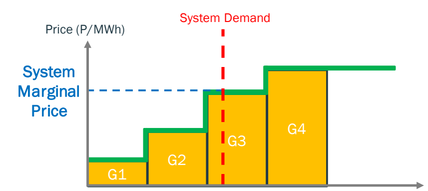

Image source: Transmission Development Plan 2014-2015 of the National Grid Corporation of the Philippines (NGCP)

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GUIDING PRINCIPLES

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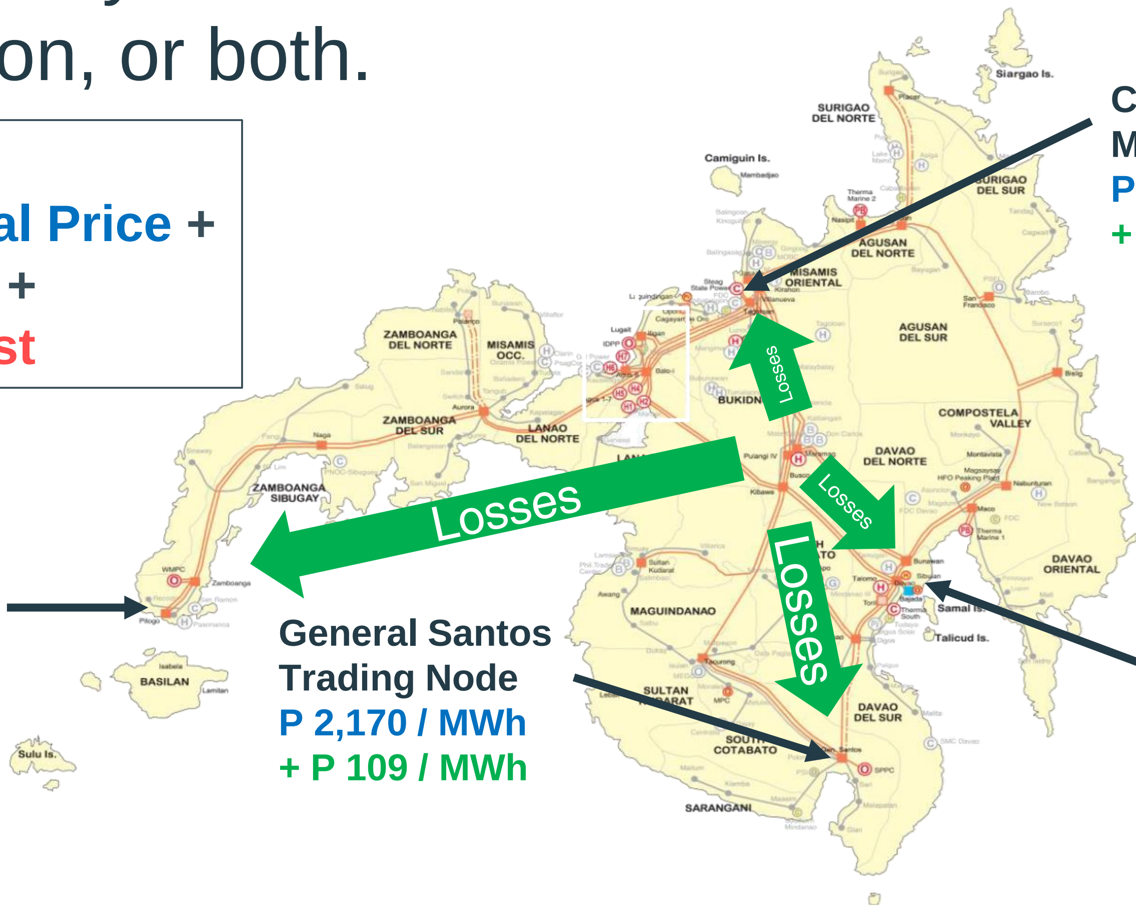
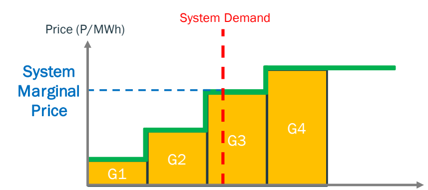


Cagayan de Oro City Market Trading Node
P 2,170 / MWh
\+ P 22 / MWh

Zamboanga Market Trading Node
P 2,170 / MWh
\+ P 325 / MWh

General Santos Trading Node
P 2,170 / MWh
\+ P 109 / MWh

Davao Market Trading Node
P 2,170 / MWh
\+ P 174 / MWh



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GUIDING PRINCIPLES

Locational Marginal Pricing / Nodal Pricing

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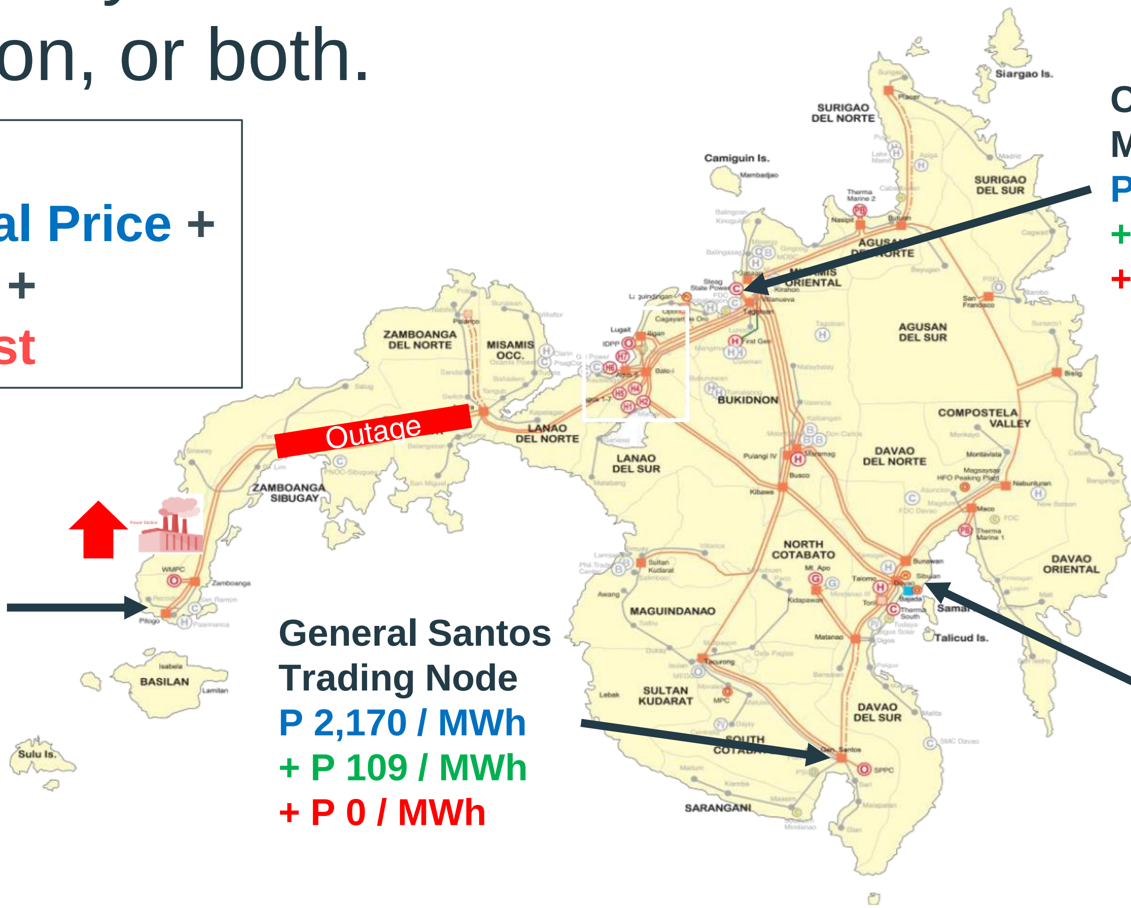
LMP =
System Marginal Price +
Cost of Losses +
Congestion Cost

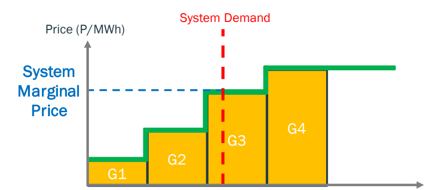


Cagayan de Oro City Market Trading Node
P 2,170 / MWh
+ P 22 / MWh
+ P 0 / MWh

Zamboanga Market Trading Node
P 2,170 / MWh
+ P 325 / MWh
+ P 1,000 / MWh

General Santos Trading Node
P 2,170 / MWh
+ P 109 / MWh
+ P 0 / MWh

Davao Market Trading Node
P 2,170 / MWh
+ P 174 / MWh
+ P 0 / MWh



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GUIDING PRINCIPLES

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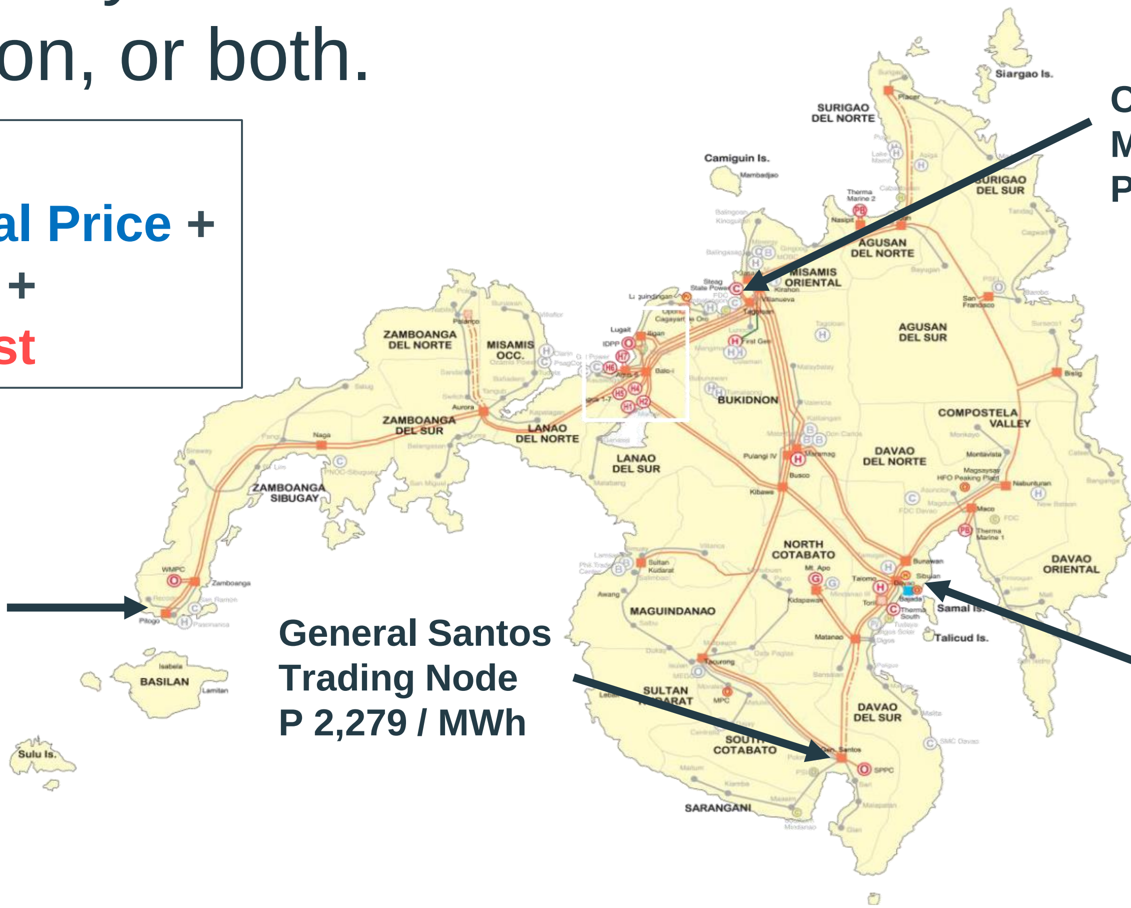
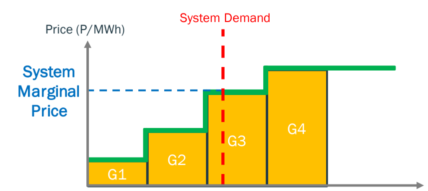


Cagayan de Oro City Market Trading Node P 2,192 / MWh

Zamboanga Market Trading Node P 3,495 / MWh

General Santos Trading Node P 2,279 / MWh

Davao Market Trading Node P 2,344 / MWh



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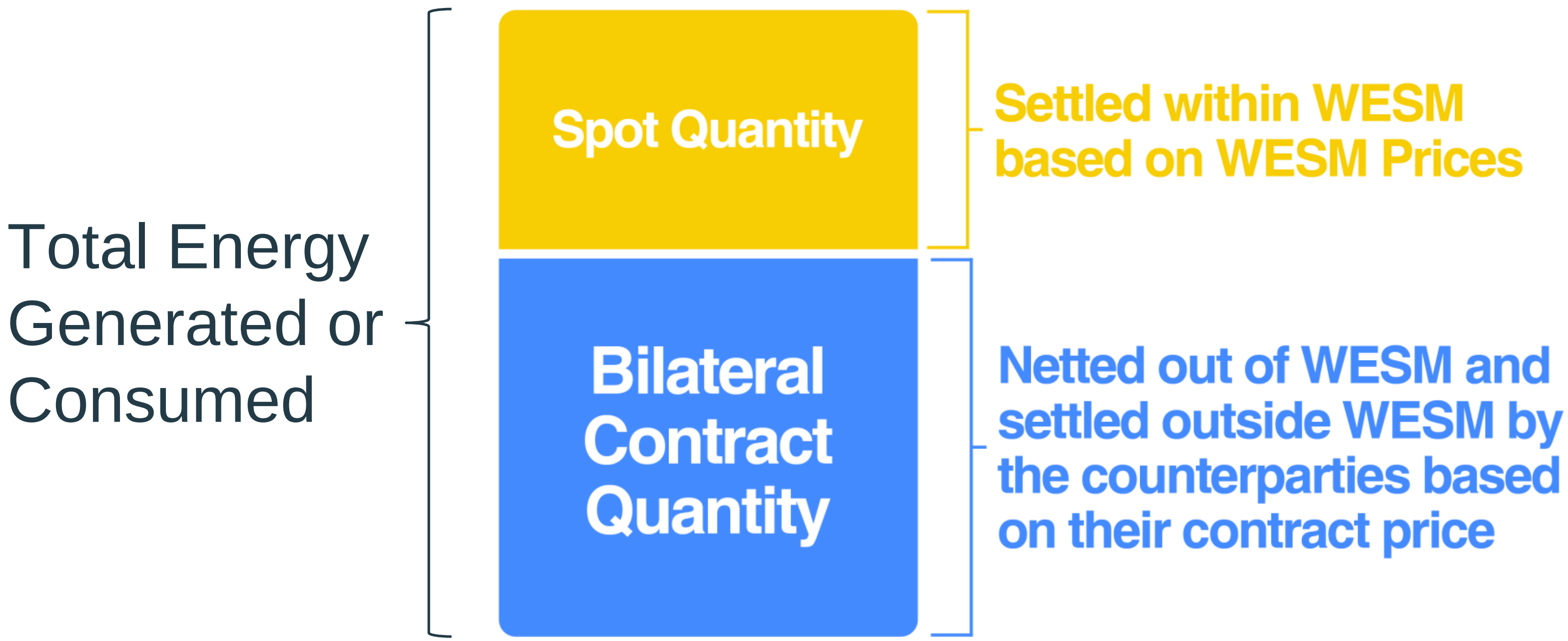
WHOLESALE ELECTRICITY SPOT MARKET POWERING PROGRESS 2006 - 2016

Image source: Transmission Development Plan 2014-2015 of the National Grid Corporation of the Philippines (NGCP)

GUIDING PRINCIPLES

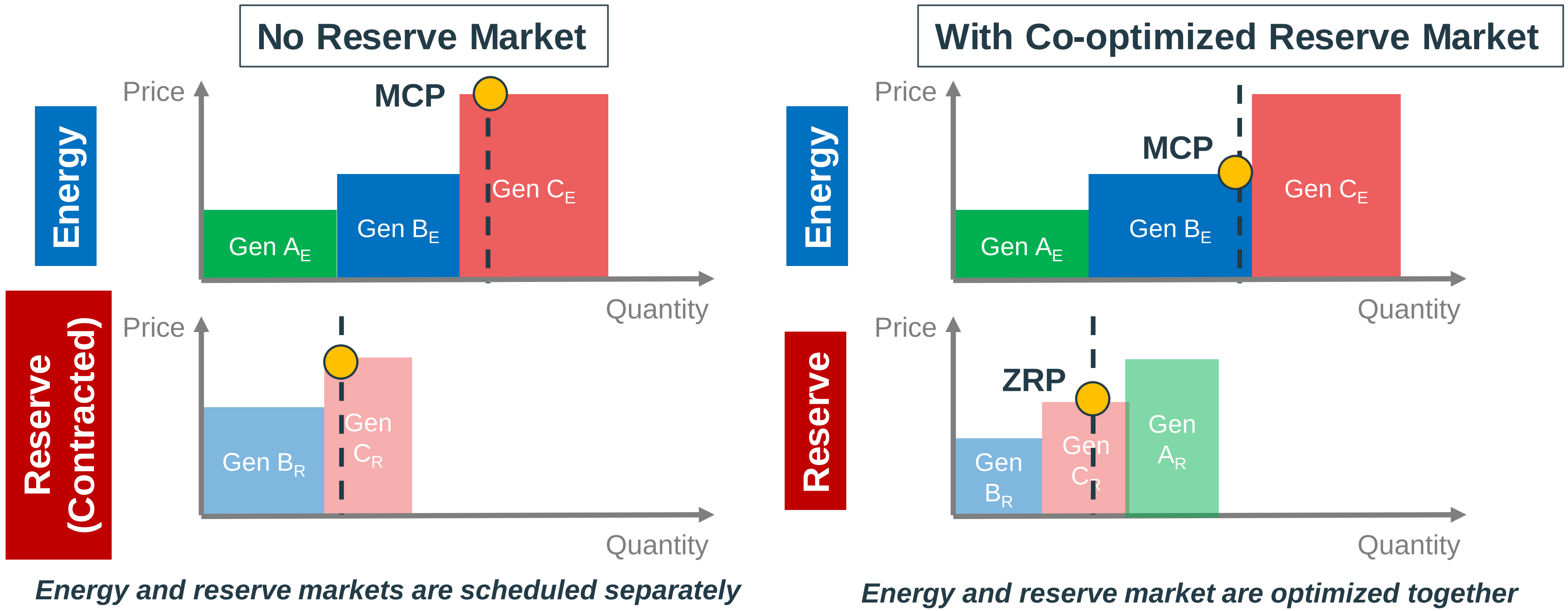
Net Settlement

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



GUIDING PRINCIPLES

Energy and Reserve Co-optimization



Advantages of Co-Optimized Reserve Market:

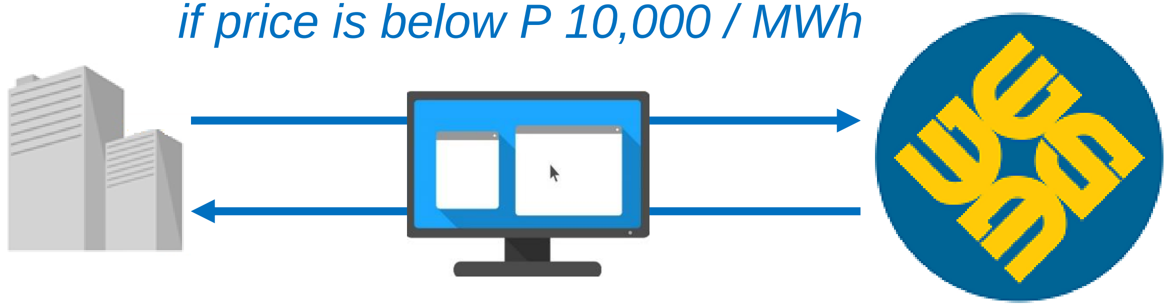
- All available capacities can be seen by the WESM
- Determination of optimal schedules and prices between energy and reserves with the least over-all cost
- Mitigate artificial under-generation

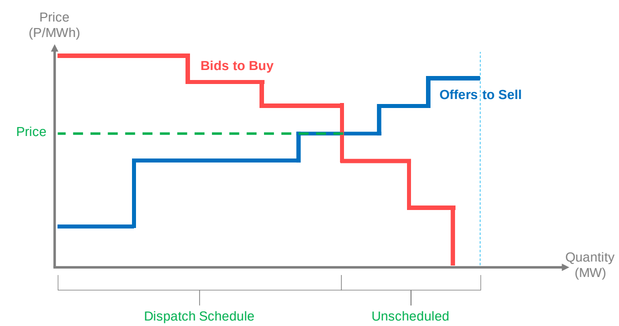
GUIDING PRINCIPLES

Demand Bidding

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

Example: I will consume 20 MW
if price is below P 10,000 / MWh



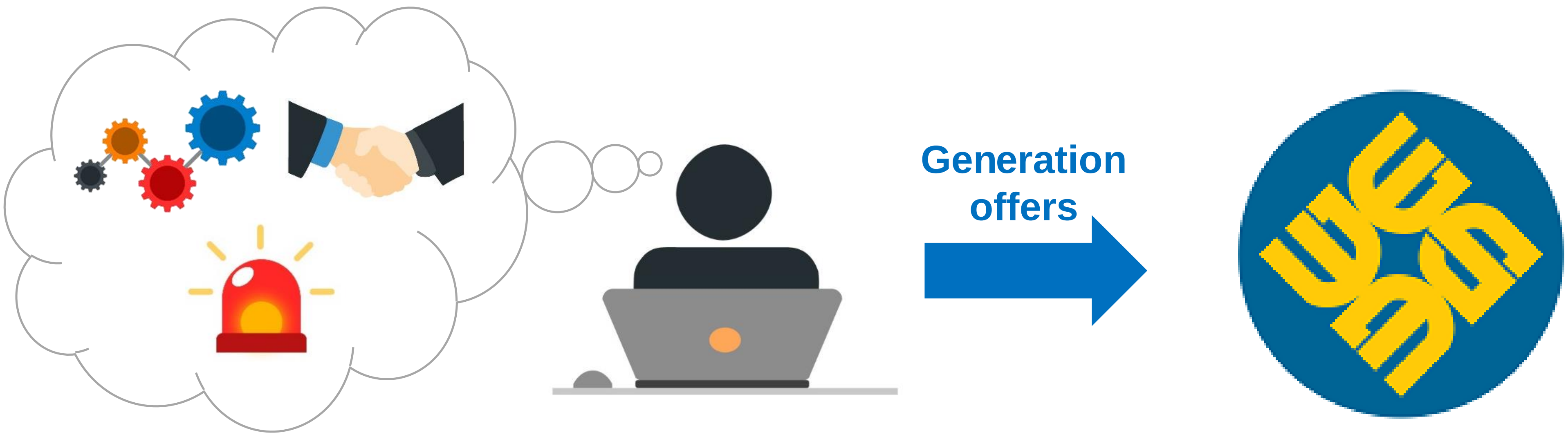


If price > P 10,000 / MWh, schedule
NOT to consume 20 MW

If price < P 10,000 / MWh, schedule
to consume 20 MW

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

Level Playing Field

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 **Stakeholder's 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