

## Notice of Market Rules Modification

**Paper No.:** EMC/RCP/25/2006/253  
**Rule reference:** Chapters 3 and 6; Appendix 6K (Proposed New Section)  
**Proposer:** Market Administration, EMC  
**Date received by EMC:** 21 February 2006  
**Category allocated:** 2  
**Status:** Not Adopted by Board  
**Effective Date:** N.A.

### Summary of proposed rule modification:

Arising from a market energy price (MEP) revision, a generator could be paid a revised MEP lower than the offer price(s) for the energy it had produced in real-time. This has negative financial impact on that generator.

Consequently, EMC proposes that an affected generator be compensated based on the difference between the revised MEP and the offer price(s) associated with the affected quantity (or quantities) of energy.

However, the RCP, by majority vote, did not support EMC's proposal. Instead, it has proposed and supported an alternative rule modification to compensate an affected generator based on difference between the revised MEP and its highest cleared offer price multiplied by its injected energy quantity (IEQ). Some RCP members felt that such proposal is consistent with the uniform marginal pricing used in the market where generators are paid the uniform clearing price times the quantity produced for the settlement of energy. In addition, they have claimed that EMC's proposal might not be sufficient for the affected generator to recover its start-up cost.

**Date considered by Rules Change Panel:** 14 March 2006; 11 May 2006; 4 July 2006 (reconsideration by RCP)

**Date considered by EMC Board:** 25 May 2006 (referred back to RCP for reconsideration); 27 July 2006

**Date considered by Energy Market Authority:**

### Proposed rule modification:

See attached paper.

### Reasons for rejection/referral back to Rules Change Panel (if applicable):

1. The Board has considered the views of the RCP. The Board also took into account the following:

- i The current market is designed to drive generator's offer to its marginal cost of production. Under the current market design, generators' offers are best proxies for their marginal costs of production. This is consistent with the fundamental design principle of marginal cost pricing (i.e. 'prices will be reflective of marginal cost') established by PHB in its wholesale design document dated 02 Aug 2000. Essentially, the aim is to allow market dynamics in the electricity market to drive market clearing prices to a competitive level that is equal to the marginal cost (MC) of most efficient bidders (i.e.  $P = MC$ ).
- ii In a competitive market, the free interaction of market supply and demand will produce an efficient outcome of  $P = MC$  where the 'Net Benefits' to society (or 'social welfare') will be maximized. This 'Net Benefit' is the sum of producers' and consumers' surpluses. In economics, producer's surplus represents profits for the producers (i.e. it captures the difference between what a supplier is paid and what it cost to supply). The Market Clearing model in SWEM essentially mimics a competitive market. Essentially, the Market Clearing Engine (MCE) also maximizes 'Net Benefit' for the electricity market through the interaction of market supply and demand. In deriving the 'Net Benefit', the MCE assigns a value to each unit of fulfilled demand and takes generators' offers as the marginal cost of fulfilling that unit demand (refer to the Objective Function in Section D.14 of Appendix 6D of the market rules).
- iii Under normal circumstances where there is no price revision, generators would be paid based on uniform marginal price. (This provides scarcity rents to incentivise generators to place offers that reflect their marginal costs). However, the market rules provide for price revision in some rare exceptional cases, for example, when there are MCE input errors.
- iv It is noted that the need for price revision is neither caused by generators nor loads. The revised MEP and USEP are used for the settlement of energy, and the prices bind both generators and loads respectively. Using the revised MEP for energy settlement could result in some generators being unable to recover their marginal costs of production. Hence, it is appropriate to offer these affected generator(s) compensation.
- v However, it is noted that the corresponding compensation amount will be recovered from loads, which also did not cause the need for price revision. Thus, there is a need to also protect consumers' interest by ensuring the compensation amount is not more than necessary. In determining the compensation quantum, there is a need to balance the interests of both generators and consumers.
- vi Hence, compensation should be to enable affected generators to recover their marginal costs for the affected quantity of energy involved (here, generators' offers are taken as proxies for their marginal costs based on the current market design), but not to include 'foregone profit'.

2. In essence, the Board feels that loads, who will be paying for the compensation and who have not caused the need for price revision, should not be made to pay for an amount that is more than necessary. Hence, the Board has decided not to adopt the proposal recommended by the RCP because it determined that the proposal would 'impose, without due justification, significant extra costs on market participants, any class of market participants or market support services licensees', as provided for under section 5.7.1, Chapter 3 of the Market Rules.

PAPER NO. : **EMC/BD/04/2006/253**

RCP PAPER NO. : **EMC/RCP/25/2006/253**

SUBJECT : **COMPENSATION ARISING FROM MARKET ENERGY  
PRICE REVISIONS**

FOR : **DECISION**

PREPARED BY : **TEO WEE GUAN  
SENIOR ECONOMIST**

REVIEWED BY : **PAUL POH LEE KONG  
SVP, MARKET ADMINISTRATION**

DATE OF MEETING : **27 JULY 2006**

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### **Executive Summary**

This paper assesses EMC's proposal to compensate generators who were paid a revised market energy price (MEP) that was lower than the offer price(s) for the energy they had produced in real-time. Currently, the market rules do not provide compensation for the affected generators.

The paper concludes that offering compensation to the affected generators is not only fair, but also boosts industry players' confidence of the market and enhances certainty for the generators.

EMC proposes that when a generator, as result of a price revision, was paid a revised MEP lower than the offer price for a certain quantity of energy it had produced in real-time, that generator would be compensated based on the difference between the revised MEP and the offer price for that affected quantity ('Proposal A').

However, the RCP, by majority vote, supported another proposal to compensate an affected generator based on difference between the revised MEP and its highest cleared offer price multiplied by its injected energy quantity ('Proposal B'). It was felt that such proposal is consistent with the uniform marginal pricing used in the market where generators are paid the uniform clearing price times the quantity produced for the settlement of energy.

## 1. Introduction

This paper assesses EMC’s proposal to compensate generators, when they as a result of a price revision, are paid a revised market energy price (MEP) that is lower than the offer price(s) for the energy they had produced in real-time. Revised MEPs are determined by re-running the market clearing engine (MCE), or by using an average of prices from the past 30 days where it is not possible to re-run the MCE.

## 2. Background

### 2.1 Price revision

The Market Rules require EMC to confirm by 12pm each day as to whether prices<sup>1</sup> determined for the previous day are final or provisional. To do this, EMC (Market Operations) conducts daily checks on the prices based on set of internal procedures<sup>2</sup>. The purpose is to ensure that the prices determined by the MCE reflect the underlying market conditions.

Provisional prices may be subject to revision. To revise the prices, EMC will perform a MCE re-run. If it is not possible to perform a re-run, EMC will use the average of past 30 days’ prices<sup>3</sup>.

### 2.2 Cases giving rise to price revision

The table below shows cases where price revision applies:

Case	Reason for price revision
The MCE has failed to produce a real-time schedule for a dispatch period for any reason other than a real-time market suspension. (Section 9.2.6, Chapter 6)	To determine prices for settlement.
The MCE has used the adjusted nodal load forecasts which to take into account the energy shortfall specified by the PSO for a dispatch period. (Section 10.2.8, Chapter 6)	To ensure that final prices reflect the energy shortfall in the dispatch period.
The MCE has applied constraint violation costs for a dispatch period and the PSO has subsequently confirmed that there was no load shed in that period. (Section 10.2.3A, Chapter 6)	To remove the effect of constraint violation penalties in energy settlement when load is not shed. (Say, due to a relaxation of line constraint.)
The MCE has used input data that are not entirely what should have been supplied to it at the time the real-time schedule for a dispatch period would normally have been produced. (Section 10.2.5, Chapter 6)	To ensure that the input data used by the MCE in determining final prices are correct and complete.

<sup>1</sup> These prices are: market energy price (MEP), Uniform Singapore Electricity Price (USEP), market reserve price (MRP) for each reserve provider group, and market regulation price (MRP).

<sup>2</sup> The internal procedures are published on the EMC’s private website. These procedures check the process of receipt, validation and processing of input information to establish the final prices.

<sup>3</sup> Except where: (1) there was a load shed, then the MEP and USEP shall be equal to the energy price ceiling; or (2) the average price of the past 30 days exceeds the applicable upper price limit specified in Appendix 6J, then that price shall be set to that upper limit.

### 2.3 Financial impact on generators

Arising from a re-run of the MCE, there will be some differences in the scheduled quantities and the associated prices between the original and revised real-time schedules (RTS) produced by the MCE.

Suppose a generator was originally scheduled to produce a certain quantity of energy at a certain MEP. However, this MEP could be revised down after a price revision. This could result in that generator being paid a MEP that is lower than the offer price(s) for energy it had already produced in real-time. Hence, this generator would not be able to recover some of its costs. The example below illustrates this.

Example:

We assume the following:

- Generator A submitted the following energy offers:

Price-Quantity Pair	Quantity (MW)	Offer Price (\$/MWh)
1	10	60
2	20	70
3	30	130
4	40	180
<b>Total:</b>	<b>100</b>	-

- The MEP for Generator A was \$3000/MWh originally, and Generator A was scheduled 100MW of energy for real-time dispatch by the MCE. Generator A complied with the real-time dispatch schedule; its injection energy quantity (IEQ) was 50MWh (i.e. a flow of 100MW for half an hour).
- Subsequently, there was a MCE re-run. This led to the original MEP being revised down to \$100/MWh.

For energy settlement, Generator A was paid the revised MEP of \$100/MWh. Since this revised MEP was below the offer price(s) for some quantities of energy which Generator A had produced, Generator A was unable to fully recover its variable costs<sup>4</sup> for those quantities (see the table below).

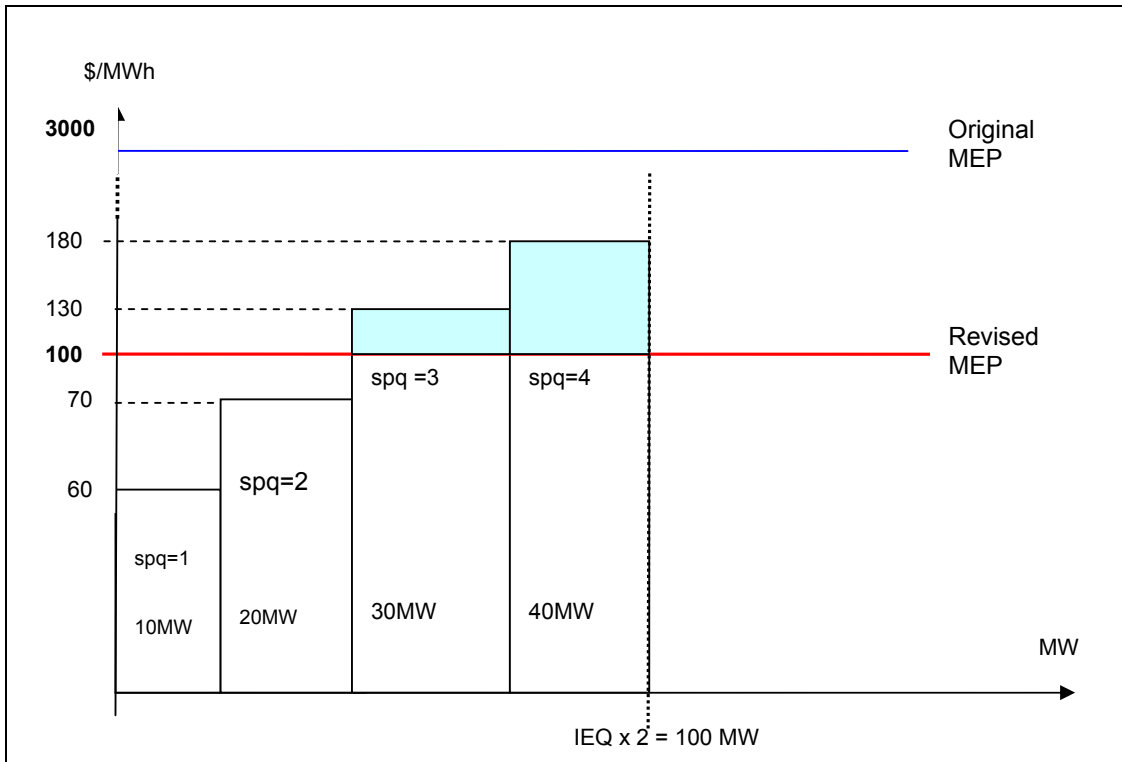
Price-Quantity Pair	Quantity (MW)	Offer Price (\$/MWh)
1	10	60
2	20	70
3	30	130
4	40	180

**Revised MEP (= \$100/MWh) < Offer Price.** Therefore, the generator is unable to fully recover its variable costs.

<sup>4</sup> Offer price serves as a proxy for the marginal cost of production for a generating unit. The area under the marginal cost curve represents the variable cost of production.

The shaded area in Figure 1 below (i.e. the blue area above offer bands 'spq 3' and 'spq 4' respectively) represents the variable cost for energy which Generator A was unable to recover.

**Figure 1: Illustration of unrecovered variable cost (equivalent to compensation payable under Proposal A – see section 3.2 of this paper)**



### 3. Analysis

This section examines compensation for generators who were paid a revised MEP that was lower than the offer price(s) for energy they had produced in real-time, as a result of a price revision. Currently, the market rules do not provide compensation for the affected generators.

#### 3.1 Rationale for compensation

The earlier example showed that a price revision can have negative financial impact on generators. This impact will be significant if: (i) the price difference between the revised MEP and the offer price for a certain quantity of energy which a generator had already produced is huge, and (ii) the quantity of energy affected is large.

It is only fair to compensate such generators in respect of a price revision. Failure to compensate these generators potentially can produce two undesirable outcomes:

- (a) it undermines the confidence industry players have in the market; and
- (b) it increases uncertainty for the generators. This, in turn, can have the following adverse impact on the market:

- One, the generators may pass on the risk to the consumers by increasing their offer prices to factor in the risk involved. If this happens, it may lead to higher cleared prices in general; and
- Two, it may reduce the incentives for generators to offer high-cost capacity into the market. One way for generators to mitigate the potential financial loss arising from a re-run is to reduce their offer of high-cost capacity into the market (since such generation would require a higher clearing price to break-even). This can be undesirable for system security since high-cost capacity is often offered by generators as 'standby' generation which responds to high forecasted prices (e.g. due to a tight supply).

In view of the above reasons, we consider that offering compensation to these generators is not only fair, but also boosts industry players' confidence of the market and enhances certainty for the generators.

### 3.2 EMC's proposal for the calculation of compensation amount

The following principles have been applied in proposing the amount of compensation to be paid to an affected generator in respect of a price revision:

- Generators should be compensated on the basis of its offer prices which serve as a proxy for the marginal cost of production. Generators should not be compensated based on the original MEP since that was an incorrect price which necessitated a price revision in the first place. Hence, arising from a price revision, if a generator had produced a certain quantity of energy but was paid a revised MEP lower than the offer price associated with that quantity, it will be compensated based on the difference between the revised MEP and the offer price for that quantity.
- The compensation regime should be simple to administer. As the circumstances under which compensation could be payable are relatively infrequent, it is not cost-effective to develop and administer a compensation arrangement which caters for every situation, especially where the financial impact is small.<sup>5</sup> Hence, we propose compensation for energy only for the affected generators;
- The basis of calculating compensation amount should, wherever possible, be consistent with other compensation guidelines endorsed by the RCP or provided for by the Market Rules<sup>6</sup>.

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<sup>5</sup> The RCP had earlier considered a paper (EMC/RCP/14/2004/02) which assessed the impact of payment discrepancies when re-run quantities of reserve and regulation are used for settlement. While it is not appropriate to settle the reserve and regulation payments based on MCE re-run quantities (instead of the PSO dispatch quantities or the original RTS), the paper concluded that the net financial impact on the MPs was small (the gross overpayments and underpayments from Jan to Mar 2004 period were \$1,080.05 and \$1,200.79 respectively). The paper further showed that this conclusion holds even if the prices for reserve and regulation were to increase 4 times. Hence, the RCP decided that the cost of investigating changes needed in the IT systems to rectify this problem would be much higher than its financial impact. Therefore, it did not recommend any modification to the market rules and the IT systems to address this problem. However, EMC continues to monitor this issue and report its monitoring to the RCP.

<sup>6</sup> In this regard, we note that the basic principle underlying the formulae in 'Concept Paper – Guidelines for Compensation (EMC/RCP/24/2006/CP11)', which had been endorsed earlier by the RCP, have proposed that MPs should be compensated based on their offer prices. Additionally, Appendix 6I in the Market Rules offers generators compensation for energy only arising from a re-run in the event where PSO forecasts an energy shortfall.

Hence, EMC proposes that when a generator, as result of a price revision, was paid a revised MEP lower than the offer price for a certain quantity of energy it had produced in real-time, that generator would be compensated based on the difference between the revised MEP and the offer price for that affected quantity ('Proposal A').

Based on the earlier example, the amount of compensation payable to Generator A under Proposal A would be represented by the blue-shaded area in Figure 1. Specifically, the compensation amount due under each specific price-quantity (spq) pair is calculated as follows:

Compensation for (spq =1) = 0 (since revised MEP > offer price);

Compensation for (spq =2) = 0 (since revised MEP > offer price);

Compensation for (spq =3)<sup>7</sup> = [(\$130 - \$100)\*0.5\*30] = \$450;

Compensation for (spq =4) = [(\$180 - \$100)\*0.5\*40] = \$1,600.

Thus, the total compensation amount for Generator A (i.e. sum of the compensation amounts across all spq) = \$0 + \$0 + 450 + \$1,600 = **\$2,050**

In essence, this total compensation amount ensures that Generator A is able to fully recover its variable costs for those quantities of energy it had produced where the associated offer prices are above the revised MEP.

### 3.3 Other considerations

The objective of the proposed compensation arrangement is to solely compensate generators (based on their offer prices) who have incurred a loss because they have produced energy based on the original RTS. These are generators which had been cleared for a certain quantity of energy based on the original RTS in real-time, but were subsequently paid a lower revised MEP as a result of a price revision after real-time. Hence, the proposed compensation arrangement makes certain exclusions as given below:

*(A): No clawing back of economic profits from generators if the revised MEP turns out higher*

As a result of price revision, it is possible that the revised MEP turns out higher than the original MEP. This would have a favorable financial impact on the generators. In such cases, we do not propose clawing back the economic profits from these generators. This is because the revised MEP is the correct price that should be used to pay the generators.

*(B): No compensation for generators scheduled to produce more energy based on the revised dispatch schedule*

The proposed compensation arrangement only seeks to compensate generators for energy they would not have produced in real-time had the revised RTS applied initially. If a generator is scheduled to produce more energy based on the revised dispatch schedule, then it would not be entitled to any compensation. This is because under the revised RTS, such a generator would have been scheduled to produce more energy (than it actually did in real-time) and would have been paid the revised MEP. Hence, this generator is actually 'better-off' than it would have had the revised RTS applied initially.

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<sup>7</sup> For a half-hourly period, the amount needs to be multiplied by half. A power flow of 30MW over half an hour gives a quantity of energy equivalent to (30MW x 0.5h) = 15MWh.

### 3.4 Implementation Options

#### 2 options for implementation

We are considering two possible options (see Annex 1) for the implementation of the rule change proposal. The table below compares these two options:

	Option 1	Option 2 <sup>8</sup>
<b>Application for Compensation</b>	<ul style="list-style-type: none"> <li>- Automatic compensation by EMC (i.e. affected gencos do not need to submit any compensation claims to EMC)</li> </ul>	<ul style="list-style-type: none"> <li>- Compensation will be based on a claim submitted by a MP (the 'claimant') to EMC. The claim should be made within 10 business days.</li> <li>- Within 20 business days of receipt of a request for compensation, EMC shall notify the claimant whether he/she is eligible for compensation and the amount payable.</li> </ul>
<b>Eligibility for Compensation and Compensation Payable</b>	<ul style="list-style-type: none"> <li>- EMC shall determine the eligibility for compensation, and the amount of compensation payable in accordance with the proposed Appendix 6K.1 (Refer to Annex 3).</li> </ul>	<ul style="list-style-type: none"> <li>- Same as Option (1)</li> </ul>
<b>Compensation Recoverable</b>	<ul style="list-style-type: none"> <li>- EMC shall calculate determine the amount to be recovered from each market participant's (MP's) load based on:   <math display="block">\frac{[(\text{total WEQ for a MP})/(\text{Sum of WEQs for all MPs})] \times (\text{total compensation amount payable})}{1}</math> </li> </ul>	<ul style="list-style-type: none"> <li>- EMC to recover the amount from loads via the Monthly Energy Uplift Charge (MEUC).</li> </ul>
<b>Timeline for Payment of Compensation</b>	<ul style="list-style-type: none"> <li>- EMC shall complete processing the compensation within 5 business days after the preliminary settlement statements of the applicable MPs for the relevant dispatch day have been</li> </ul>	<ul style="list-style-type: none"> <li>- The claimant will notify EMC if it agrees with the amount of compensation decided by EMC. If it does, EMC shall pay the money to the claimant after the amount has been recovered through the MEUC. However,</li> </ul>

<sup>8</sup> Under Option (2), the timeline relating to 'Application for Compensation' and 'Payment of Compensation' follows that provided for under section 3.11 of Chapter 3 ('Application for Compensation') of the Market Rules.

	Option 1	Option 2 <sup>8</sup>
	<p>issued;</p> <ul style="list-style-type: none"> <li>- The compensation amount payable and/or the amount recoverable will appear in the next available preliminary settlement statements of the applicable MPs.</li> <li>- Payment shall be made in accordance with the settlement timetable set out in section 5.2 of chapter 7.</li> </ul>	<p>payment to the claimant must not be made later than 90 days after the date of the notification from claimant to EMC agreeing on the compensation amount.</p>
<p><b>Cost and time required for implementation (Estimates provided by EMC – Details are attached in Annex 2)</b></p>	<ul style="list-style-type: none"> <li>- Estimated 182 man-days (approximately 9 months) required to carry out implementation work.</li> <li>- Rules will become effective in about 15 months<sup>9</sup> after they have been approved by the EMA.</li> <li>- Perform externally. (Estimated IT costing ranged from \$175,000 to \$236,000.)</li> </ul>	<ul style="list-style-type: none"> <li>- Estimated 50 man-days (approximately 2.5 months) required to carry out implementation work.</li> <li>- Rules will become effective in about 4 months<sup>10</sup> after they have been approved by the EMA.</li> <li>- Perform using in-house resources. (Estimated internal costing of \$48,000.)</li> </ul>

Evaluation of Implementation Options

We give the pros and cons for Option 1 and Option 2 below:

	Option 1	Option 2
<p><b>Pros</b></p>	<ul style="list-style-type: none"> <li>- Compensation payable to affected gencos is made on an automatic basis (i.e., affected gencos need not submit compensation claims to EMC).</li> <li>- Recovery of compensation cost adheres to allocative-matching principle (i.e. recover costs from only those who purchase</li> </ul>	<ul style="list-style-type: none"> <li>- Less costly and less time required to implement.</li> <li>- Can be implemented using in-house resources.</li> </ul>

<sup>9</sup> Man-effort required is estimated to be about 9.1 months. However, some tasks can be performed concurrently by multiple resources and hence, this would reduce the elapsed time. EMC (IT) estimates the overall elapsed time required is approximately 8 months after the rules have been approved by the EMA. However, EMC(IT) will be implementing a code freeze from 01 Oct 06 to Apr 07 (i.e. a total of about 7 months). Any outstanding system changes will have to be deferred till April 07. Hence, due to the elapsed time and code freeze, the rules can only come into effect in about (8+7)= 15 months after they have been approved by the EMA.

<sup>10</sup> Based on the planned projects and resources available, EMC is likely to be able to start work in 1-2 months after the rules have been approved by the EMA. On top of that, EMC (Market Operations) requires approximately 2.5 months (i.e. 50 man-days) for implementation work. The total elapsed time from the point EMA approved the rule to the implementation date is about 3-4 months.

	Option 1	Option 2
	<p>electricity in the affected period(s)).</p> <ul style="list-style-type: none"> <li>- Affected gencos can get payment more quickly (it can be up to about 27 days after the relevant dispatch day).</li> </ul>	
<b>Cons</b>	<ul style="list-style-type: none"> <li>- More costly and longer time required to implement.</li> <li>- Implement using external resources</li> </ul>	<ul style="list-style-type: none"> <li>- Places onus on the affected gencos to submit a compensation claim to EMC.</li> <li>- Recovery of compensation cost violates the allocative-matching principle (i.e. the compensation costs will be shared among all MPs with WEQs, instead of only by those with WEQs in the affected dispatch period(s)).</li> <li>- Affected gencos get payment only after the compensation amount has been recovered through MEUC (it can be up to 90 days after the date of the notification from claimant to EMC agreeing on the amount of compensation).</li> </ul>

The detailed proposed rules for Option 1 and Option 2 are attached in **Annex 3** and **Annex 4** respectively.

We note that there are two main disadvantages associated with Option 2. One, it is administratively more cumbersome since affected generators would need to submit a claim for compensation to the EMC. Two, the manner in which compensation cost is being recovered violates the allocative-matching principle.

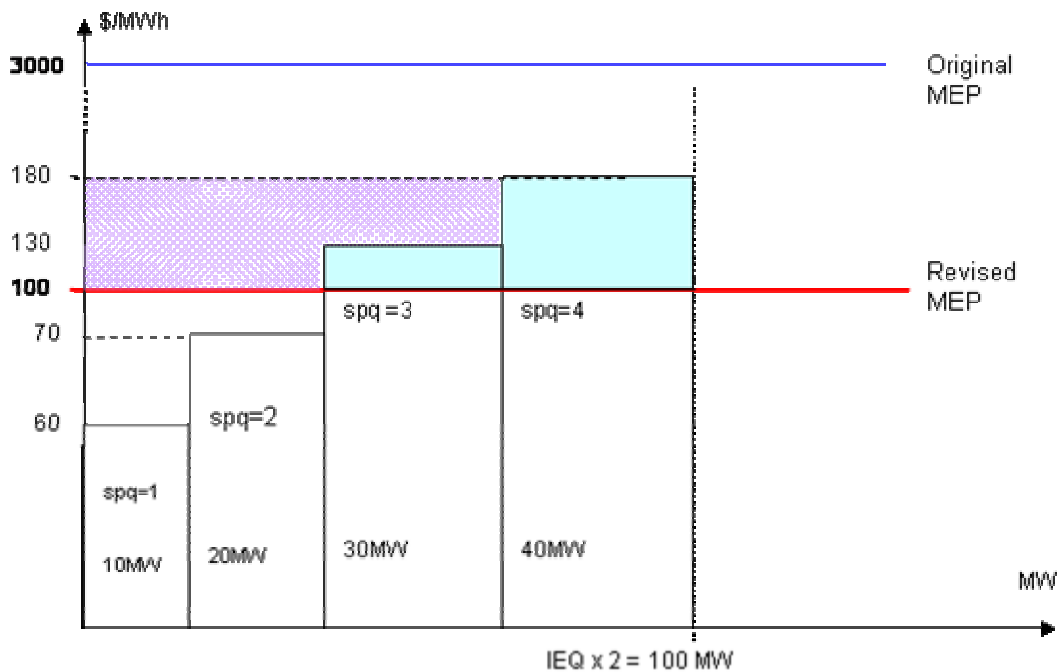
However, given the relatively infrequent re-runs we have to date (in 2005, we had re-run for only 53 out of a total of 17,520 dispatch periods), we do not consider the disadvantages of Option 2 to have a significant impact on the affected generators. Also, Option 2 is significantly cheaper and requires less time to implement, compared to Option 1. Hence, on balance, we recommend that the RCP support Option 2 for implementation.

**4. Deliberation by the RCP**

EMC presented Proposal A to the RCP for consideration at the meeting on 14 Mar 06. At that meeting, the RCP tasked EMC to re-examine the proposed formula in Proposal A used to calculate the compensation amount for an affected generator.

Specifically, a few RCP members had proposed that the compensation amount be calculated base on the difference between the revised MEP and the highest offer price cleared multiplied by the generator's IEQ ('Proposal B'). This is represented by the blue- and purple-shaded area in the diagram below (as opposed to only the blue-shaded area under Proposal A).

**Figure 2: Illustration of compensation payable under Proposal B**



These RCP members felt that Proposal B is consistent with the uniform marginal pricing used in the market where generators are paid the uniform clearing price times the quantity produced for settlement of energy.

EMC evaluated Proposal B and the claims made by these RCP members. In its evaluation, EMC considered that the need for such compensation arises because the wrong MEP had been applied initially. Neither the generators nor the loads are at fault for the wrong determination of the MEP. Hence, it is fair that an affected generator is being offered compensation. However, given that the compensation amount will be recovered from loads, such amount should not exceed the 'deadweight loss' (or 'excess burden') which measures the social cost arising from an inefficient outcome (i.e. erroneous scheduling arising from the wrong MEP being applied initially). The purpose of compensating an affected generator is to enable that generator to recover its variable costs incurred in generating the affected quantities due to the initial wrong real-time schedules and not to compensate it for lost profit.

Further, it was claimed that compensating an affected generator based on Proposal A is insufficient to allow that generator to cover its start-up cost. However, EMC feels that this is not a compelling claim. In general, where a generator expects to be running over several

dispatch periods, scarcity rents (or 'profits') that are earned through marginal cost pricing under normal circumstances and accumulated over a period of time should allow that generator to cover its start-up costs. And, where a generator expects to run only for a single dispatch period, its initial offer would have already incorporated its start-up costs.

In conclusion, EMC still maintains that Proposal A is appropriate in that an affected generator will be compensated such that it can recover its variable costs incurred for producing the affected quantities of energy. Since a generator's offer is the best proxy for its marginal cost, the variable cost involved is essentially represented by the area under the offer curve/stack for the affected quantities of energy. This is consistent with how the market is designed and generators are expected to offer as such.

Overall, Proposal A still best meets the dual objectives of ensuring that an affected generator can recover its variable costs incurred for the affected quantities of energy, while keeping the costs to loads to no more than the 'excess burden' imposed on the society. (Please refer to Annex 5 for the details on EMC's evaluation.)

EMC presented its evaluation to the RCP at its meeting on 15 May 06. Some of the RCP members disagreed with EMC's evaluation. These members maintained that an affected generator should be compensated based on the difference between the revised MEP and the highest offer price cleared multiplied by that generator's IEQ (i.e. Proposal B). They insisted that such proposal is consistent with uniform marginal pricing adopted by the market. In addition, they argued that a generator's offers do not necessarily reflect its marginal costs (although EMC's view is that they should be intended as such under the current market design).

Proposal B and the implementation of it using option 2 were put to a vote at that meeting. 5 members voted for it, while 3 others voted against it. The record of votes is as follows:

For;                    Mr. Philip Tan (Tuas Power)  
                             Mr. Tay Swee Lee (Senoko Power)  
                             Mr. Low Boon Tong (PowerSeraya)  
                             Mr. Robin Langdale (check name)  
                             Mr. Dallon Kay (Diamond Energy)

Against:              Mr. Kng Meng Hwee (PSO)  
                             Mr. Francis Gomez (SembCorp Cogen)  
                             Mr. Henry Gan (EMC)

Abstain:                Mr. Lim Ah Kuan (SP Services)

Hence, by majority vote, the RCP supported Proposal B and the implementation using Option 2. The proposed rules giving effect to RCP's decision are attached in Annex 6.

## **5. Conclusion**

This paper assesses EMC's proposal to compensate generators who, as a result of price revision, were paid a revised MEP that was lower than the offer price(s) for energy they had produced in real-time.

EMC proposed that an affected generator be compensated based on the difference between the revised MEP and its offer price(s) for the affected quantity of energy (Proposal A).

However, by majority vote, the RCP supported the proposal that an affected generator be compensated based on difference between the revised MEP and its highest cleared offer

price multiplied by its IEQ (Proposal B). It was felt that such proposal is consistent with the uniform marginal pricing used in the market where generators are paid the uniform clearing price times the quantity produced for the settlement of energy. In addition, the RCP also supported Option 2 for the implementation.

## 6. Impact on market systems

For the recommended Option 2, there will be no changes to EMC's production system. EMC (Market Operations) will develop a standalone compensation calculator to calculate the compensation amount payable to eligible generators after receiving a claim for compensation from them.

## 7. Implementation process

For the recommended Option 2, the time required for implementation is estimated by the EMC (Market Operations) to be about 4 months after the EMA has approved the proposed rule changes. The implementation work can be done in-house, with an estimated internal resource costing of \$48,000. (Please see Annex 2 for details on the implementation process for Option 2.)

## 8. Consultation

We have published EMC's rule modification proposal on the EMC website for comments. Comments have been received as follows:

### **From PSO**

PSO submitted its comments on 02 Mar 06. Below, we give PSO's comments and provide our responses to them.

**Comment (1):** "As NEMS is an ex-ante market, EMC should address the fundamental issue of "WHY" is there a need to have MCE re-run/price revision, "WHAT" are the purposes/intend of re-runs, i.e. other than when the MCE fails to produce any real-time dispatch schedule for a particular dispatch period as stated in MR Chapter 6 Section 9.2.6, what other reasons would have prompted EMC to initiate a MCE re-run/price revision. Bearing in mind that real-time dispatch schedule and prices produced by the MCE are binding on both the Buyer (EMC) and the Sellers (Gencos and ILP), any revision after the fact would be amounting to an Ex-post pricing against the NEMS design principle of settlements of using ex-ante prices and instructions."

### **Response**

*The RCP can task EMC to undertake a review on price revision/re-run in NEMS. However, we recommend the review to be undertaken as a separate project. We envisage that the review will be an extensive exercise, and will result in findings with major implications for different parties. Meanwhile, we still need to put in place a compensation arrangement to address situations where gencos are paid a revised MEP that is lower than the offer price(s) for the energy they had produced in real-time arising from a price revision, unless the gencos can agree that such an arrangement is not required until such time the EMC comes out with its findings on the review of price revision/re-run.*

**Comment (2):** "Assuming there is a need to revise the prices, Option (1), automatic calculation of additional payment, should be termed as 'Constraint-on Payment', rather than another form of compensation as GRF were constrained-on by the MCE in the original

dispatch schedule. PSO is of the view that any form of compensation should conform to the guidelines already in place in the Compensation Regimes.”

Response

*The proposed rules for determining the eligibility for compensation and calculating the compensation amount payable are the same for both Option (1) and Option (2). These two options differ only in terms of compensation application procedures, the method used for recovering the cost of compensation from loads and the timeline for payments.*

*We have avoided using the term ‘constrained-on payment’ in the proposed rules as (1) this term is not defined anywhere in the market rules or in other governing documents, and (2) in addition to the definition, we still need to specify the circumstances when a ‘constrained-on’ generator is entitled to compensation and when it is not. Hence, the proposal rules have attempted to make it clear that this compensation arrangement applies only in respect of a MEP revision leading to a generator being paid a revised MEP lower than its offer price(s) for energy they had already provided in real-time. This will be subject to that generator being eligible for compensation as described in the paragraph directly below.*

*If after re-running the MCE, the EMC determines that a generator would need to provide more energy (than what it had initially produced in real-time) based on the revised dispatch schedule, then that generator would not be entitled to compensation. The reason being, if the revised RTS (which is the correct) schedule had applied originally, that generator would have produced more energy in real-time and received the lower MEP price. The fact that it had produced less energy in real-time (than what it should have had the revised RTS been applied originally) means that that generator was actually in a ‘better-off’ position. Hence, there is no compensation for such a generator.*

*The proposed compensation arrangement is consistent with the guidelines for compensation, section 3.11 of chapter 3, endorsed by the RCP earlier. (We have used offer curve as the basis for calculating compensation, and affected generators will be compensated based on the difference between revised MEP and offer price(s) for the affected quantity of energy).*

**Comment (3):** “Assuming the proposed rules change is approved, then in the event when there is no real-time dispatch schedule from MCE, PSO will provide within 3 business days upon request from EMC, dispatch instruction issued by PSO during the affected periods.”

Response

*Under Option (2), since the application for compensation is based on a claim submitted by a MP, and EMC has 20 business days to process the compensation claim, we are agreeable to PSO providing EMC with the dispatch instruction (where no real-time RTS has been produced) within 3 business days upon receiving a request from EMC..*

*Under Option (1), where compensation is made ‘automatically’ to the affected generator(s), EMC will need the dispatch instruction from PSO for **every** case where no real-time RTS has been produced by the MCE. Under this option, we would suggest that PSO provides EMC with the dispatch instruction within 3 business days after the date of the affected dispatch period.*

**From Senoko Power**

Senoko Power Ltd submitted its comments on 06 Mar 06. The full comments are attached in Annex 7. Below, we highlight their concerns and provide our responses to them.

**Concern 1: The need for a re-run.** NEMS runs on an ex-ante basis. Re-run should only exist in exceptional circumstances. Rule change proposal should also address issues beyond that

of compensation. The RCP should address the following: (i) why was the re-run performed, (ii) Under what circumstances should a re-run be performed, and (iii) did such circumstances arise for P26 on 11 Nov 05?

Response

*We note that in an ideal situation, there should not be any price revision in an ex-ante market. However, prices determined by the MCE sometimes do not reflect the actual underlying market conditions and hence, that necessitated a price revision. Having said this, RCP can task the EMC to undertake a review of price revision in NEMS as a separate exercise. It is envisaged that this can be an extensive exercise. Meanwhile, it is still necessary to have this compensation arrangement in place.*

*The Market Rules currently provide for the circumstances where price revision applies. (Please refer to section 2.2 of this paper.)*

*In regard to Senoko's query on the circumstance(s) which gave rise to a re-run for P26 on 11 Nov 05, it should not be an issue for the RCP to consider. Senoko should direct this issue to EMC separately.*

**Concern 2: Reinstate 'Constrained-On' Payment.** The only instance in which a price revision is necessary is during a 'constrained-on' situation, which used to be recognised in SEP but does not exist in NEMS. During such situations necessitating a price revision, a constrained-on payment should be paid to the GRF. "Constrained-on' payment was in place in the former SEP should be re-instated.

Response:

*Under the SEP rules, 'constrained-on' is defined as 'the operation of a generating set that is instructed by the Pool to increase its output while other generating sets with lower offer price bids are held at less than full output in order to avoid violating a transmission constraint'. In this regard, 'constrained-on' situations under SEP are similar to those in NEMS where PSO can instruct a generating unit to provide more output than the scheduled quantity to ensure system reliability.*

*Generating sets which have been instructed to provide more output compared to what they have been scheduled can claim for compensation under section 3.11 of Chapter 3. Hence, although 'constrained-on' payment is nowhere mentioned specifically in the Market Rules, provisions for generating sets to seek compensation of this sort have been provided for in the Market Rules..*

**Concern 3: Compensation Amount.** Affected units should be compensated at the MNN price for the entire IEQ, and not based on the price bands at which their bids were submitted. EMC should adhere to the norm of paying GRF at its MNN price.

Response:

*A GRF is paid based on the revised MNN price for its entire IEQ. The GRF should not be paid based on the original MNN prices because those prices are incorrect, which necessitated a price revision in the first place.*

*However, we note that paying a GRF based on the revised MNN price can result in that GRF making 'losses' on a certain quantity of energy (where the offer price(s) is/are above the revised MNN price) it had already produced when it should not have had the original RTS been correct. Hence, the compensation regime aims to compensate that GRF for the 'losses' incurred (and not for the 'profits' forgone) for those affected quantities, i.e. to ensure that the GRF can 'break-even' for those affected quantities of energy.*

*This recommendation takes into account that compensation cost is recovered from the loads (even though the compensation arose from incorrect RTS being applied originally), and compensation of this sort only adds costs to the market without further benefits. Hence, this proposed solution of compensating generating sets based on the difference between the revised MEP and their offer price(s) seeks to achieve the dual objectives of ensuring that generating sets can recover their variable costs involved for the affected quantities of energy, while keeping the added costs to the market (loads specifically) as low as possible.*

## 9. Legal sign off

Text of the rule modification has been vetted by EMC's external legal counsel whose opinion is that the modification reflects the intent of the rule modification proposal.

## 10. Reconsideration by RCP

### Consideration by the EMC Board

The rule change proposal was tabled at the EMC Board's meeting on 24 May 06. EMC Board considered Proposal B which was supported by the RCP. However, the Board referred the rule change proposal back to the RCP for reconsideration on the following grounds:

- i The current market is designed to drive generator's offer to its marginal cost of production. Under the current market design, generators' offers are best proxies for their marginal costs of production. This is consistent with the fundamental design principle of marginal cost pricing (i.e. 'prices will be reflective of marginal cost') established by PHB in its wholesale design document dated 02 Aug 2000. Essentially, the aim is to allow market dynamics in the electricity market to drive market clearing prices to a competitive level that is equal to the marginal cost (MC) of most efficient bidders (i.e.  $P = MC$ ).
- ii In a competitive market, the free interaction of market supply and demand will produce an efficient outcome of  $P = MC$  where the 'Net Benefits' to society (or 'social welfare') will be maximized. This 'Net Benefit' is the sum of producers' and consumers' surpluses. In economics, producer's surplus represents profits for the producers (i.e. it captures the difference between what a supplier is paid and what it cost to supply<sup>11</sup>). The Market Clearing model in SWEM essentially mimics a competitive market. Essentially, the Market Clearing Engine (MCE) also maximizes 'Net Benefit' for the

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<sup>11</sup> That is, marginal revenue (MR) minus marginal cost (MC). In a competitive market, MR is equal to the market clearing price (P) and all producers are price-taker. For each unit sold, the producer will receive MR (=P) and the cost involved for producing that unit is MC.

electricity market through the interaction of market supply and demand<sup>12</sup>. In deriving the 'Net Benefit', the MCE assigns a value to each unit of fulfilled demand<sup>13</sup> and takes generators' offers as the marginal cost of fulfilling that unit demand (refer to the Objective Function in Section D.14 of Appendix 6D of the market rules).

- iii Under normal circumstances where there is no price revision, generators would be paid based on uniform marginal price. (This provides scarcity rents to incentivise generators to place offers that reflect their marginal costs). However, the market rules provide for price revision in some rare exceptional cases, for example, when there are MCE input errors.
- iv It is noted that the need for price revision is neither caused by generators nor loads. The revised MEP and USEP are used for the settlement of energy, and the prices bind both generators and loads respectively. Using the revised MEP for energy settlement could result in some generators being unable to recover their marginal costs of production. Hence, it is appropriate to offer these affected generator(s) compensation.
- v However, it is noted that the corresponding compensation amount will be recovered from loads, which also did not cause the need for price revision. Thus, there is a need to also protect consumers' interest by ensuring the compensation amount is not more than necessary. In determining the compensation quantum, there is a need to balance the interests of both generators and consumers.
- vi Hence, compensation should be to enable affected generators to recover their marginal costs for the affected quantity of energy involved (here, generators' offers are taken as proxies for their marginal costs based on the current market design), but not to include 'foregone profit', i.e. generators should be compensated based on only the blue-shaded area in Figure 2 above.

#### Conclusion by EMC Board

In conclusion, uniform pricing is not applicable to situations where there are price revisions. Compensation for affected generators should be to ensure they can recover their marginal costs of production and should not include 'forgone profits'. Additionally, there is a need to balance both generators' and consumers' interests. The EMC Board thus referred the rule change proposal back to the RCP for reconsideration.

#### Reconsideration by RCP

The RCP reconsidered the rule change proposal at its 27th meeting on 4 July 06. The RCP was informed of the Board's decision and its deliberation.

However, some RCP members still feel that Proposal B is the more appropriate solution. To them, Proposal B offers a 'middle-ground' solution between paying a generator based on the original price (i.e. equivalent to no re-run) and paying it based on the revised price. However, EMC disagreed with this. The rules currently require EMC to conduct a re-run to obtain the revised price for settlement if the original price determined initially was wrong. Hence, a comparison which involves using the original price is inappropriate. Instead, the comparison should involve what an affected generator currently gets, i.e. the revised price, versus what it would get if Proposal A and Proposal B were put in place. Seen this light, Proposal A would instead offer the 'middle-ground' solution. However, EMC feels that there are other more important considerations (i.e. the main one being that affected generators should be

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<sup>12</sup> The market supply is derived by aggregating the supply bids and the market demand is the system load forecasts provided by the PSO. The intersection point of the market supply and demand establishes the market clearing price.

<sup>13</sup> There is no demand bidding. Demand curve is taken to be perfectly inelastic. Hence, MCE assigns a fixed value to each unit of fulfilled demand.

compensated based on costs and not 'lost profits') in determining what is the appropriate amount of compensation to pay generators.

Also, some members felt that the principle of determining compensation should be consistent with uniform pricing used in settlement. They contended that generators submit their offers based on the understanding that uniform pricing is used in settlement. Additionally, offers submitted by generators do not necessarily reflect their marginal costs in practice, even though the market design purports as such.

The RCP was asked if they would want to assess the financial impact under both proposals before making its final decision. However, majority of the RCP has decided not to have the assessment and to move forward with recommending Proposal B to the EMC Board.

The record of vote for Proposal B is as follows:

For:            Mr. Philip Tan (Tuas Power)  
                  Mr. Tay Swee Lee (Senoko Power)  
                  Mr. Low Boon Tong (PowerSeraya)  
                  Mr. Daniel Cheng (SPPA)  
                  Mr. Robin Langdale

Against:       Mr. Francis Gomez (SembCorp Cogen)  
                  Mr. Henry Gan (EMC)

Abstained:    Mr Kng Meng Hwee (PSO)  
                  Mr Dallon Kay (Diamond Energy)

In conclusion, the RCP (by majority vote) still supports Proposal B and recommends that the EMC Board adopts it (the proposed rules are set out in Annex 6).

## **11. Recommendations**

By majority vote, the RCP recommend that the EMC Board:

- a. **adopt** the proposed rule modifications set out in **Annex 6** (i.e. Proposal B);
- b. **seek** EMA's **approve** the proposed rule modifications set out in **Annex 6**; and
- c. **recommend** that the rule modification proposal come into force **4 months** after the date on which the approval of the Authority is published by the EMC.

**ANNEX 1    2 Options for Implementation**

Option 1:

- Automatic compensation by the EMC (i.e. affected gencos do not need to submit any compensation claims to EMC; whenever there is a price revision, EMC will determine the compensation amounts for those gencos);
- EMC shall:
  - o calculate the compensation amount payable to each relevant genco in accordance with section K.1 of Appendix 6K the proposed rules; and
  - o determine the amount to be recovered from each market participant (MP) who purchases electricity in the affected dispatch period(s). For an affected dispatch period, the share apportioned to each MP will be based on the purchase volume (i.e. WEQ) of that MP over the total purchase volume for the wholesale market in that period, i.e.

$$\left( \frac{\text{Total WEQ for a MP}}{\text{Total WEQ for all MPs}} \right) \times (\text{Total Compensation Amount Payable})$$

EMC shall do these within 5 business days after the preliminary settlement statements of the applicable MPs for the relevant dispatch day have been issued;

- The compensation amount payable and/or amount recoverable will appear in the next available preliminary settlement statements of the applicable MPs.

Option 2:

- Compensation will be based on a claim submitted by a MP (the 'claimant') to EMC; A claimant shall make its request for compensation within 10 business days of the date that:
  - o the events giving rise to the potential entitlement to compensation occurred;
  - or
  - o the claimant knew or should have reasonably known of the events giving rise to the potential entitlement to compensation,
 whichever is later. (Note: This timeline is the same as that under section 3.11.2 of Chapter 3);
- Within 20 business days of receipt of a request for compensation, EMC shall notify the claimant whether he/she is eligible for compensation and the amount payable in accordance with section K.1 of Appendix 6K of the proposed rules. (Note: This timeline is the same as that under section 3.11.4 of Chapter 3);
- The claimant will notify the EMC if it agrees with the amount of compensation decided by the EMC. If it does, the EMC shall pay the money to the claimant after the amount has been recovered through the MEUC. However, payment to the claimant must not be later than 90 days after the date of the notification from claimant to EMC agreeing on the amount of compensation.

(Note: If claimant disagrees with amount, the matter shall be referred to the dispute resolution counselor where the matter shall proceed for arbitration as provided for under the Market Rules.)

**ANNEX 2 Cost and Time Estimates Provided by EMC**

Option 1:

<b>Activity</b>	<b>Estimated effort (man-days)</b>
Requirement definition	4
Use-case documents updates and review	8
System Design / Produce Technical Specs	8
Database implementation	7
PL/SQL development	23
Front-end development	15
Unit and integration testing	15
Test planning and documentation	7
Release packaging and deployment	5
Peer review	7
Project management activities	10
UAT support and bug fix	10

Settlements Performance Tuning	10
Contingency (10%)	13
<b>Total estimated IT effort</b>	<b>142</b>

Market Operations UAT	30
IT Systems Setup for Testing	10
<b>Total estimated effort</b>	<b>182 (9.1 months)</b>

Although the estimate is for 9.1 man-months of effort, some of the tasks can be performed concurrently by multiple resources which will reduce the elapsed time (but not the effort). EMC would require an additional 4 weeks to mobilise resources.

The overall elapsed time that EMC will require is likely to be approximately 8 months after the rules have been approved.

However, EMC will be implementing a code freeze from 01 Oct 06 to Apr 07 (approximately 7 months). Any changes to the EMC system will have to be deferred till after Apr 07.

Hence, due to code freeze and elapsed time involved, the rules can only become effective in about  $(8 + 7) = 15$  months after they have been approved by the EMA.

Indicative estimate IT costs to perform this externally are \$175,000 to \$236,000 based on 152 man days, \$1000-\$1350 per man day, and a rough 15% fixed price premium.

Option 2:

<b>Activity</b>	<b>Estimated effort (man-days)</b>
To scope the specification of the standalone compensation calculator	5
To develop a standalone compensation calculator	30
To test the standalone compensation calculator	5
To setup business processes, forms and templates and brief MPs on the manual compensation process	10
<b>Total estimated effort :</b>	<b>50 (2.5 months)</b>

For Option 2, the estimated man-effort is 50 man-days (approximately 2.5 months).

It is assumed that market operation is doing this work. Based on the planned projects (e.g. there are number of market clearing testings like PST, MCE upload dot net parallel run, etc., that need to be done) and resources available, EMC (MO) will require an additional lead time of 1-2 months after the rules have been approved before it can start working on the implementation.

The total elapsed time from the point EMA approved the rules to the implementation date is about 3 -4 months.

Using estimated internal resource costing figure (\$120 per hour), the indicative cost for option 2 is \$48,000.

**ANNEX 3 Proposed rule modifications (For Option 1)**

Existing Rules (Release: 1 January 2006, read together with rule changes approved by the EMA as at 21 February 2006)	Proposed Rules (Deletions represented by strikethrough text and addition underlined)
<p><b>Chapter 6</b></p> <p>(No existing provision)</p>	<p><b>Chapter 6</b></p> <p><u>10.2.10</u> Where the <i>EMC</i> determines <u>settlement</u> data described in section 10.2.1 pursuant to section <u>10.2.3A.2, 10.2.5, 10.2.5A, 10.2.5B or 10.2.6</u>, the <i>EMC</i> shall also determine if compensation would be payable to any <u>market participant</u> with one or more <u>generation registered facilities</u> in accordance with Appendix 6K. Such compensation, if determined by the <i>EMC</i> to be payable to such a <u>market participant</u>, shall be included in its next available <u>preliminary settlement statement</u>. All such compensation (if payable) shall be recoverable by the <i>EMC</i> pursuant to sections <u>K.2.2 and K2.3 of Appendix 6K</u>.</p>

## Proposed Rules (Cont'd) – New Appendix 6K of Chapter 6

## APPENDIX 6K – COMPENSATION ARISING FROM MARKET ENERGY PRICE REVISIONS

### K.1 CALCULATING COMPENSATION AMOUNTS

K.1.1 For this section K.1, the following definitions apply:

$RMEP^m$  = revised *market energy price* (in \$/MWh) at *MNN* *m* for the relevant *dispatch period* determined by (i) re-running the *market clearing engine* pursuant to sections 10.2.3A.2, 10.2.5, 10.2.5A or 10.2.5B of this Chapter, or (ii) applying section 10.2.6 of this Chapter.

$IEQ^m$  = injection *energy quantity* (in MWh) for *GRF* *m* for the *settlement interval* corresponding to the relevant *dispatch period*.

$spq$  = index of a specific *price-quantity pair* in an *energy offer*.

$pq$  = index of a *price-quantity pair* in an *energy offer*, ordered by increasing price.

$Q^{m,pq}$  = quantity of a *price-quantity pair*  $pq$  for the *energy offer* for *GRF* *m* for the relevant *dispatch period*.

$P^{m,pq}$  = price of a *price-quantity pair*  $pq$  for the *energy offer* for *GRF* *m* for the relevant *dispatch period*.

$COMP^{m,pq}$  = compensation payable in relation to a *price-quantity pair*  $pq$  of the *energy offer* for *GRF* *m* for the relevant *dispatch period*.

$COMP^m$  = compensation payable in relation to the *energy offer* for *GRF* *m* for the relevant *dispatch period*.

K.1.2 Under this section K.1, where the *EMC* determines a revised *market energy price* for a given *dispatch period* by re-running the *market clearing engine* pursuant to sections 10.2.3A.2, 10.2.5, 10.2.5A or 10.2.5B of this Chapter, a *market participant* with a *generation registered facility* is eligible for compensation only if the *EMC* determines that (a) the quantity of *energy* scheduled for that *generation registered facility* based on its *real-time dispatch schedule* for that *dispatch period*, is more than (b) the quantity of *energy* scheduled for that *generation registered facility* for that *dispatch period* after re-running the *market clearing engine*. If a *dispatch instruction* for that *generation registered facility* for that *dispatch period* was issued by the *PSO* pursuant to section 9.1.2.2 of Chapter 5, then the *EMC* shall use the quantity of *energy* specified in that *dispatch instruction* for the purpose of section K.1.2(a)

instead. The *PSO* shall provide such *dispatch instruction* to the *EMC* within three *business days* after the date of that *dispatch period*.

K.1.3 Subject to sections K.1.2, the compensation as described in section 10.2.10 of this Chapter for a *generation registered facility* of a *market participant* shall be calculated as follows:

$$\text{COMP}^m = \sum_{pq=1}^{10} \text{COMP}^{m,pq}$$

K.1.4 For the purposes of section K.1.3, the compensation payable for each *price-quantity pair*  $spq$  of the *energy offer* of a *generation registered facility* shall be calculated as follows:

K.1.4.1 If  $P^{m,spq} \leq \text{RMEP}^m$ , then

$$\text{COMP}^{m,spq} = 0$$

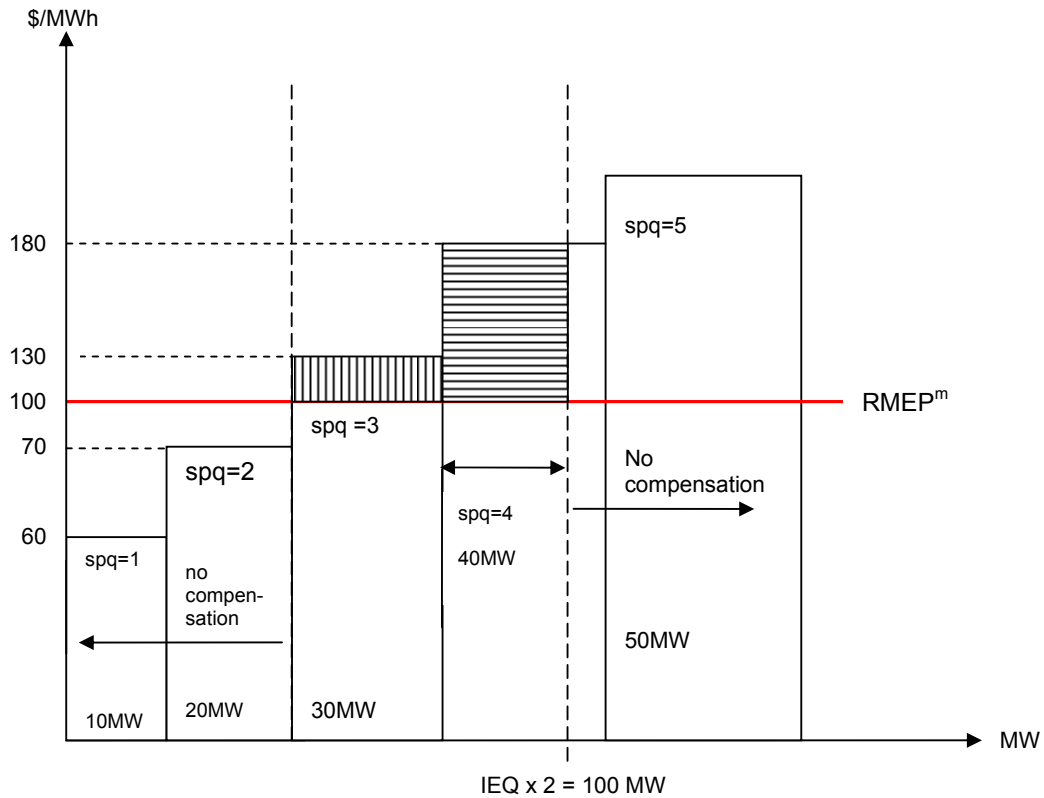
K.1.4.2 If  $\sum_{pq=1}^{spq-1} Q^{m,pq} \geq (\text{IEQ}^m \times 2)$ , then

$$\text{COMP}^{m,spq} = 0$$

K.1.4.3 Otherwise, the compensation payable for *price-quantity pair*  $spq$  is:

$$\text{COMP}^{m,spq} = (P^{m,spq} - \text{RMEP}^m) \times 0.5 \times \left[ \min \left( \sum_{pq=1}^{spq} Q^{m,pq}, (\text{IEQ} \times 2) \right) - \sum_{pq=1}^{spq-1} Q^{m,pq} \right]$$

**Explanatory Note – The following example illustrates the compensation calculation**




Suppose IEQ = 50MWh for a generator, and that generator is eligible for compensation under K.1.2. Then, the compensation for each *price-quantity pair* (spq) of that generator is calculated as follows:


$$COMP^{m,1} = 0 \text{ (Based on condition K.1.4.1)}$$

$$COMP^{m,2} = 0 \text{ (Based on condition K.1.4.1)}$$

$$COMP^{m,3} = (130 - 100) \times 0.5 \times (\min(60,100) - 30) = 30 \times 0.5 \times 30 = \$450$$

(Based on condition K.1.4.3. The amount is represented by half of the shaded area )

$$COMP^{m,4} = (180 - 100) \times 0.5 \times (\min(120,100) - 60) = 80 \times 0.5 \times 40 = \$1600$$

(Based on condition K.1.4.3. The amount is represented by half of the shaded area )

$$COMP^{m,5} = 0 \text{ (Based on condition K.1.4.2)}$$

Therefore, the compensation payable to that generator is:

$$COMP^m = COMP^{m,1} + COMP^{m,2} + COMP^{m,3} + COMP^{m,4}$$

$$= \$0 + \$0 + \$450 + \$1600 = \mathbf{\$2,050} \text{ (Based on condition K.1.3)}$$

**K.2**      **COMPENSATION PAYMENT AND RECOVERY**

K.2.1      The compensation for a given *dispatch period* referred to in section K.1.3 shall be calculated by the *EMC* no later than five *business days* after the *preliminary settlement statement*, of the applicable *market participant* who is to be compensated, for the relevant *dispatch day* containing that *dispatch period* has been issued by the *EMC*.

K.2.2      All compensation amounts for a given *dispatch period* payable under section 10.2.10 of Chapter 6 shall be recovered by the *EMC* from *market participants*, by apportioning the sum of those amounts to be recovered among *market participants* in proportion to the sum of the WEQs (if any) associated with their respective *settlement accounts* in respect of that *dispatch period*.

K.2.3      Each amount to be so recovered from a *market participant* pursuant to section K.2.2 shall:

K.2.3.1      be determined by the *EMC* no later than five *business days* after the *preliminary settlement statement*, of that *market participant* from whom recovery is to be made, for the relevant *dispatch day* containing that *dispatch period*, has been issued by the *EMC*; and

K.2.3.2      when determined by the *EMC*, be included in the next available *preliminary settlement statement* of that *market participant*.

**ANNEX 4 Proposed rule modifications (For Option 2)**

Existing Rules (Release: 1 January 2006, read together with rule changes approved by the EMA as at 21 February 2006)	Proposed Rules (Deletions represented by strikethrough text and addition underlined)												
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<p>3.11.1 If a <i>market participant</i> or a <i>market support services licensee</i> (the "<i>claimant</i>") seeks compensation under section 3.3.1.5, the <i>claimant</i> shall submit its request to the <i>EMC</i> or the <i>PSO</i>. The request shall:</p> <p>3.11.1.1 meet the requirements of the</p>	<p>3.11.1 If a <i>market participant</i> or a <i>market support services licensee</i> (the "<i>claimant</i>") seeks compensation under section 3.3.1.5, the <i>claimant</i> shall submit its request to the <i>EMC</i> or the <i>PSO</i>. The request shall:</p> <p>3.11.1.1 meet the requirements of the</p>												

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<p>3.11.1.2 relevant <i>market manual</i> or the <i>system operation manual</i>; refer to the section of the <i>market rules</i> that the request is based on; and</p> <p>3.11.1.3 specify the amount of compensation sought.</p>	<p>3.11.1.2 relevant <i>market manual</i> or the <i>system operation manual</i>; refer to the section of the <i>market rules</i> that the request is based on; and</p> <p>3.11.1.3 specify the amount of compensation sought <u>(except where the request relates to compensation under section 10.2.10 of Chapter 6).</u></p>
<p><b>Chapter 6</b>  (No existing provision)</p>	<p><b>Chapter 6</b> <u>10.2.10</u> Where the <i>EMC</i> determines <u>settlement data described in section 10.2.1 pursuant to section 10.2.3A.2, 10.2.5, 10.2.5A, 10.2.5B or 10.2.6, a market participant with one or more generation registered facilities may seek compensation from the EMC in accordance with section 3.11 of Chapter 3. For the purposes of section 3.11.4 of Chapter 3, the EMC shall determine the relevant claimant's eligibility for compensation and the amount of such compensation, if any, in accordance with Appendix 6K.</u></p>

Proposed Rules (Cont'd) – New Appendix 6K of Chapter 6

## **APPENDIX 6K – COMPENSATION ARISING FROM MARKET ENERGY PRICE REVISIONS**

### **K.1 CALCULATING COMPENSATION AMOUNTS**

Proposed rules are the same as those under section K.1 of Appendix 6K in Annex 3, except for section K.1.2 where the proposed rules are as follows:

- K.1.2 Under this section K.1, where the *EMC* determines a revised *market energy price* for a given *dispatch period* by re-running the *market clearing engine* pursuant to sections 10.2.3A.2, 10.2.5, 10.2.5A or 10.2.5B of this Chapter, a *market participant* with a *generation registered facility* is eligible for compensation only if the *EMC* determines that (a) the quantity of *energy* scheduled for that *generation registered facility* based on its *real-time dispatch schedule* for that *dispatch period*, is more than (b) the quantity of *energy* scheduled for that *generation registered facility* for that *dispatch period* after re-running the *market clearing engine*. If a *dispatch instruction* for that *generation registered facility* for that *dispatch period* was issued by the *PSO* pursuant to section 9.1.2.2 of Chapter 5, then the *EMC* shall use the quantity of *energy* specified in that *dispatch instruction* for the purpose of section K.1.2(a) instead. The *PSO* shall provide such *dispatch instruction* to the *EMC* within three *business days* after the date of receipt by the *PSO* of a request for such *dispatch instruction* from the *EMC*.

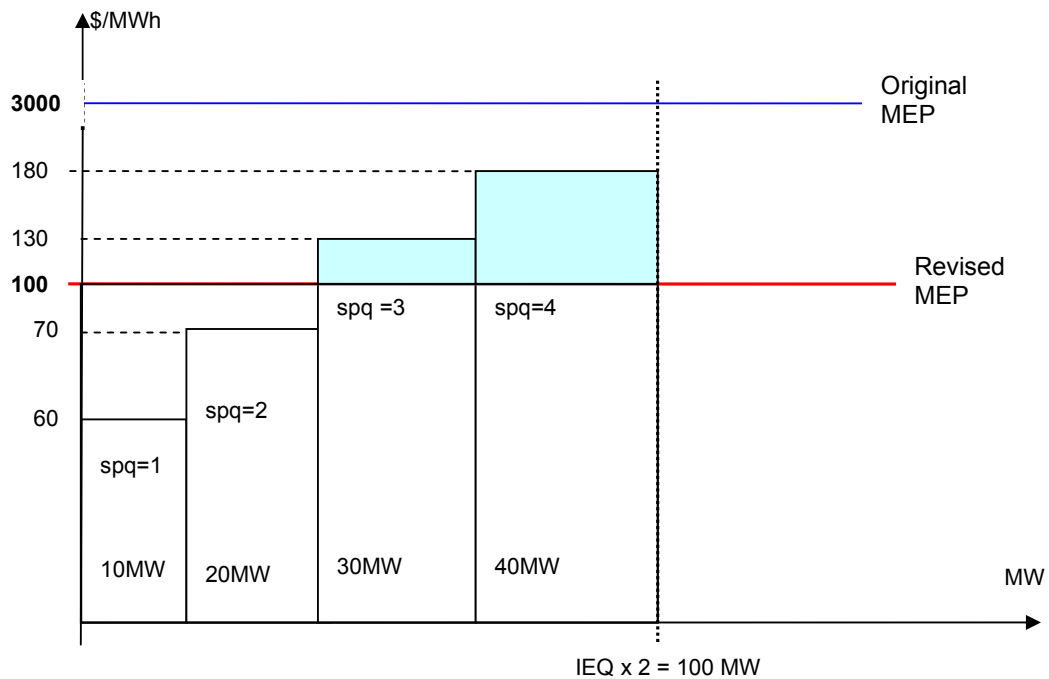
(The proposed section K.2 of Appendix 6K in Annex 3 is not required.)

**ANNEX 5 EMC’s Evaluation of the Formula Proposed by Some RCP Members**

**Background**

At its last meeting in Mar 06, the RCP tasked EMC to re-examine the basis of determining the compensation amount for a generator who was paid a revised MEP that was lower than the offer price(s) for the energy it had produced in real-time.

In the rule change paper no.: EMC/RCP/25/2006/253, EMC proposed that the compensation amount be based on the difference between the revised MEP and the offer price(s) for that quantity of energy that the generator had produced in real-time. The diagram below illustrates this:



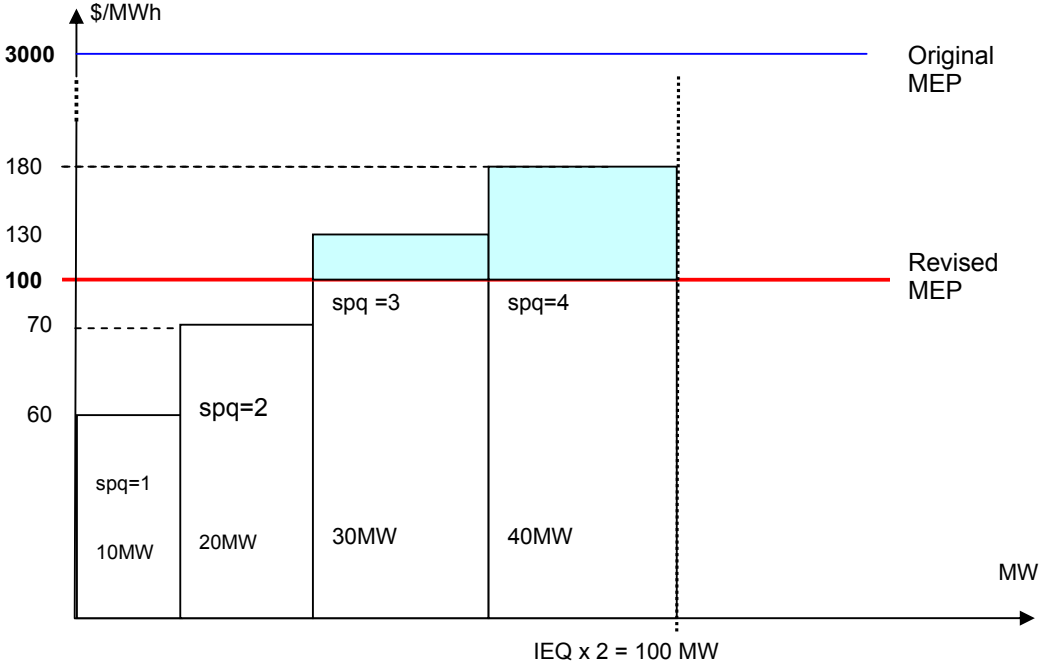
We assume the Generator A’s IEQ was 50MWh (i.e., 100MW × ½-hour). The original MEP was \$3,000/MWh, but this was revised to \$100/MWh following a price revision. Hence, Generator A would be paid a revised MEP lower than its offer prices for offer bands 3 and 4 (i.e., a total of 35MWh of energy was paid a revised MEP lower than the offer prices associated with that quantity of energy).

Using the compensation formula proposed by EMC, Generator A would receive the following compensation amount:

$$\text{Compensation amount} = \frac{1}{2}\text{-hour} \times [30\text{MW} \times (\$130/\text{MWh} - \$100/\text{MWh}) + 40\text{MW} \times (\$180/\text{MWh} - \$100/\text{MWh})] = \$2,050$$

This is equivalent to ½ times the blue shaded area in the above diagram. (Note: Generator A would have received: 50MWh × \$100/MWh = \$5,000 for energy settlement at the revised MEP.)

Some Panel members have asked EMC to re-examine the proposed formulae used to determine the compensation amount. It was suggested that the compensation amount be based on the difference between the revised MEP and the offer price of the highest-priced offer band cleared multiplied by the generator's IEQ. Based on the same example used earlier, this is equivalent to compensation amount represented by 1/2 times the total shaded area in the diagram below:



Hence, Generator A would receive the following compensation amount instead:

$$\text{Compensation amount} = \frac{1}{2}\text{-hour} \times [(\$180/\text{MWh} - \$100/\text{MWh}) \times 100\text{MW}] = \$4,000$$

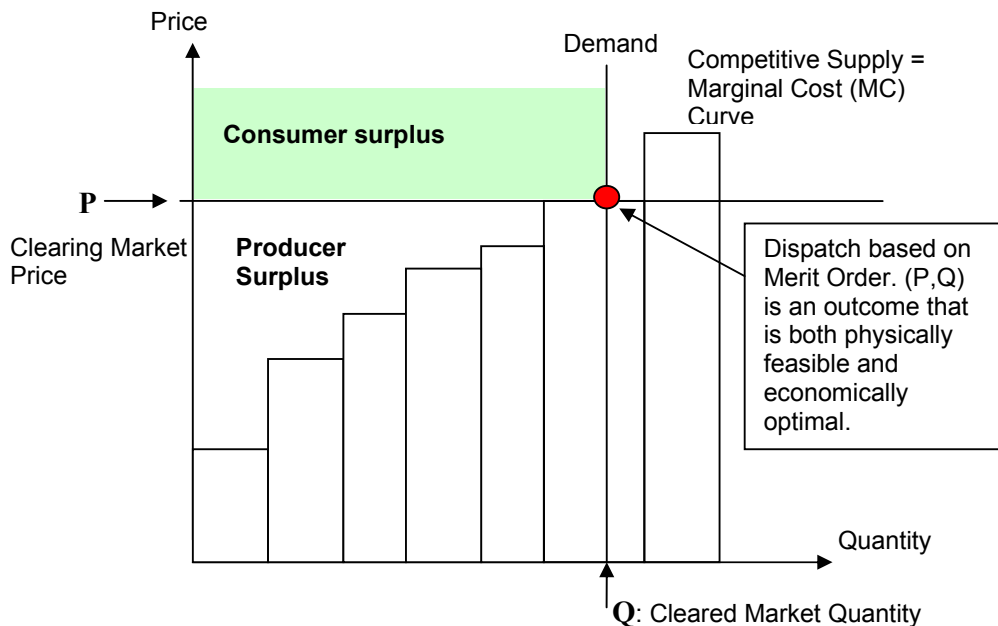
This amount is higher compared to the amount worked out earlier based on EMC's proposal (the excess being represented by  $\frac{1}{2}$  times the purple shaded area in the diagram above).

It was argued that such proposed compensation arrangement is consistent with the uniform marginal pricing used in the market where generators are paid the uniform clearing price times the quantity produced for settlement of energy. EMC has considered the suggestion expressed by these Panel members. We present our views below.

### Achieving Efficiency

One key objective of deregulation is to achieve efficiency through competition. Below, we briefly describe the market clearing mechanics which is essential to understanding how the MCE obtains an efficient outcome.

In the clearing the market, the MCE achieves efficiency by seeking to maximise the total surplus (i.e., the sum of producer and consumer surpluses), subject to a set of physical constraints. (See the diagram below.) The MCE has an assigned value to each unit of fulfilled demand and takes generator offers as the costs of fulfilling that demand.



The market demand is based on the total load forecast supplied by the PSO, and the market supply is given by the (horizontal) aggregation of offers submitted by individual generators.

Essentially, the efficient outcome (P, Q) is determined through the interaction of the market supply and demand<sup>14</sup>. Such outcome is not only physically feasible (since it satisfies the set of physical constraints), but also minimizes the cost of what is produced and maximizes the value of what is consumed (i.e. it maximizes the total surplus). It gives the right amount of production and consumption. In short, such outcome results in a dispatch that is both physically feasible and economically optimal.

For payment to generators, the market adopts uniform (marginal) pricing, i.e. all cleared generators would receive a uniform market clearing price, P, for each unit of energy they had produced.

### **The role of marginal cost**

The auction design described above has the advantage of being theoretically cost revealing in a competitive<sup>15</sup> market. Bidders will have incentive to submit offers that reflect their true (marginal) costs in such a cost-based power auction. They know that if any of their offers is rejected because there are other sufficient lower offers to satisfy load, they will be better off, because they will not have committed themselves to sell at prices that fail to cover their variable (avoidable) costs. Also, they know that on their accepted offers, they will receive the market clearing price, regardless of the level of their own offer prices, permitting them to pocket the difference between their variable costs and the market clearing price as a necessary contribution toward short-term profits<sup>16</sup>.

Based on this current market design, marginal costs of generators play a key role in that they not only define the individual generators' supply curves<sup>17</sup>, but also help to determine the competitive market clearing price. If all bidders tell the truth, the outcome will be efficient. Ideally, in a competitive electricity market, the clearing price, P, will always equal system marginal cost.

### **Basis for compensation**

The rule change proposal ('EMC/RCP/25/2006/253') seeks to compensate generators for the production of energy which they would not have produced had the revised MEP applied originally. We note that offering compensation to the affected generators is not only fair, but also helps to boost the confidence market players have of the market.

However, the need for such compensation arises due to a wrong determination of the prices by the MCE initially. The compensation amount will be recovered from loads to pay the affected generators. This adds costs to consumers without a commensurate increase in benefits to them. We explain this further below.

Let (P,Q) represent the efficient outcome for the market had the MCE determined the original RTS correctly. (See the Figure 1 below.) Under normal/typical circumstances, the schedule for

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<sup>14</sup> The marginal generator is determined by matching offers from generators to load forecast at each node to develop a classic supply and demand equilibrium price. This process is carried out for each half-hour interval at each input and offtake node on the transmission grid. The prices take into account the losses and constraints in the system and generators are dispatched by the system operator, not only in ascending order of offers, but in accordance with the required security of the system. This results in a spot market with "bid-based, security-constrained, economic dispatch with nodal prices".

<sup>15</sup> According to Stoff (2003), this requires at least 3 conditions to be met: price-taking suppliers, public knowledge of the market price, and well-behaved production costs.

<sup>16</sup> This is different from pay-as-bid which will inevitably reduce efficiency because generators will find themselves forced to depart from marginal cost bidding if they are receive any contributions for their fixed costs or contribution to profits. For more details on uniform (marginal) pricing versus pay-as-bid pricing, see Alfred, et al. (2003).

<sup>17</sup> To find the market (aggregate) supply curve, individual supply curves are summed horizontally.

dispatching generators will simply consist of an ordered list of the least expensive generators (as indicated by their offer prices) necessary to meet system (forecast) demand at that time<sup>18</sup>.

Suppose an error in the determination of the RTS by the MCE resulted in an inefficient outcome which departed from (P,Q). Essentially, the dispatch was still physically feasible (i.e., Q was still satisfied), but it was not economically optimal.

The inefficiency arose because the MCE had scheduled higher-priced generator(s) for dispatch when Q could originally have been satisfied by lower-priced generator(s) instead. (See Figure 2 below where cheaper generators 6, 7 and 8 have been displaced by more expensive generators 9, 10 and 11.) This could be due to, say, the MCE modelling a non-physical constraint in the network which resulted in a need to dispatch some higher-priced generators to avoid load shed. Under locational pricing, this caused a price separation where market prices are higher in the 'expensive location' relative to that in the 'cheaper location'<sup>19</sup>. In effect, this makes the supply function more convex than the underlying bids submitted by generators originally might suggest. (Compare the merit order in Figure 1 and in Figure 3.)

The inefficient outcome has imposed an 'excess burden' (known as a 'deadweight loss' in economics) on the society where the marginal cost (MC) of production outweighs the marginal benefit (MB) of consumption. This burden/loss could have been avoided had there been no error in the scheduling initially. This loss is represented by the blue shaded area in Figure 3.

Given that deadweight loss measures the social cost that resulted from an inefficiency, the compensation amount to be borne by consumers should not exceed this cost (i.e. the blue shaded area in Figure 3). Since marginal cost is best used as a proxy for a generator's supply, the amount essentially represents the variable cost of production. (Note: This is consistent with the formula proposed by EMC for compensating affected generators in its rule change proposal.)

Some players, however, have expressed concern that compensating the affected generators based on the formulae proposed by EMC is insufficient to allow them cover their start-up costs<sup>20</sup>. However, this is not a compelling argument. In general, where generators expect to be running over several dispatch periods, scarcity rents that are earned through marginal cost pricing under normal circumstances and are accumulated over a period of time should allow the generators to cover their start-up costs<sup>21</sup>. And where generators expect to run for only a single dispatch period, their initial bid would have already incorporated the start-up costs.

Hence, in conclusion, we do not support paying affected generators the highest cleared offer for the entire quantity produced as that will only impose extra costs on the consumers in excess of the 'deadweight loss' (such excess given by the purple shaded area in Figure 3) which cannot be justified from the societal welfare point of view.

We maintain that the proposed formulae set out in the rule change paper no.: EMC/RCP/25/2006/253 best meet the dual objectives of ensuring that affected generators can recover their variable costs involved for the affected quantities of energy, while keeping the costs to consumers to the minimum possible.

## **Recommendation**

We recommend that the RCP support the rule change proposal ('EMC/RCP/25/2006/253') with no change to the proposed formulae contained therein.

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<sup>18</sup> This is also known as 'merit order' where we have a ranking by marginal cost of generators.

<sup>19</sup> See Hunt (2000), pg. 178 – 180.

<sup>20</sup> Start-up costs are incurred arising from starting up a generator.

<sup>21</sup> See Stoff (2003), Section 1-6.6. Scarcity rent is revenue minus costs that vary with outputs. Start-up costs have first claim on scarcity rents. After startup and no-load costs are subtracted from scarcity rents, short-run profits remain. Short-run profits help firms to cover fixed cost. (Note: No-load cost is the cost of running a generator while producing no output. No-load cost remains the same at all output levels. (See pg. 444)

Figure 1- Typical dispatch with no scheduling error

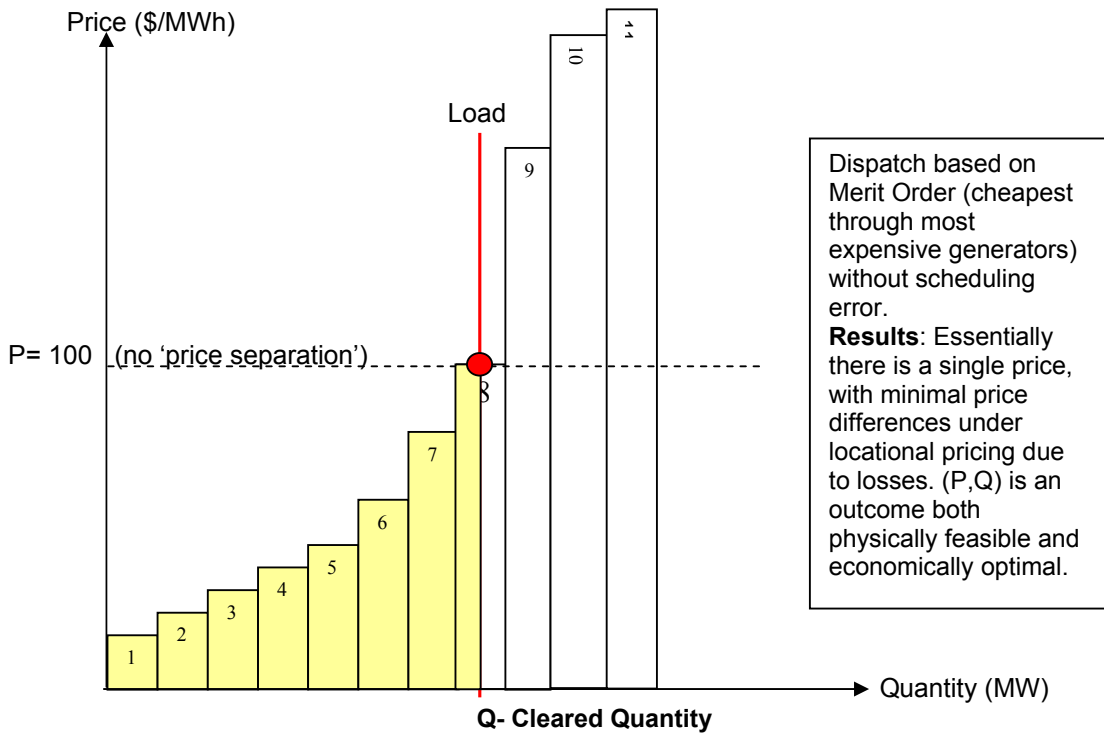


Figure 2 – Dispatch arising from scheduling error

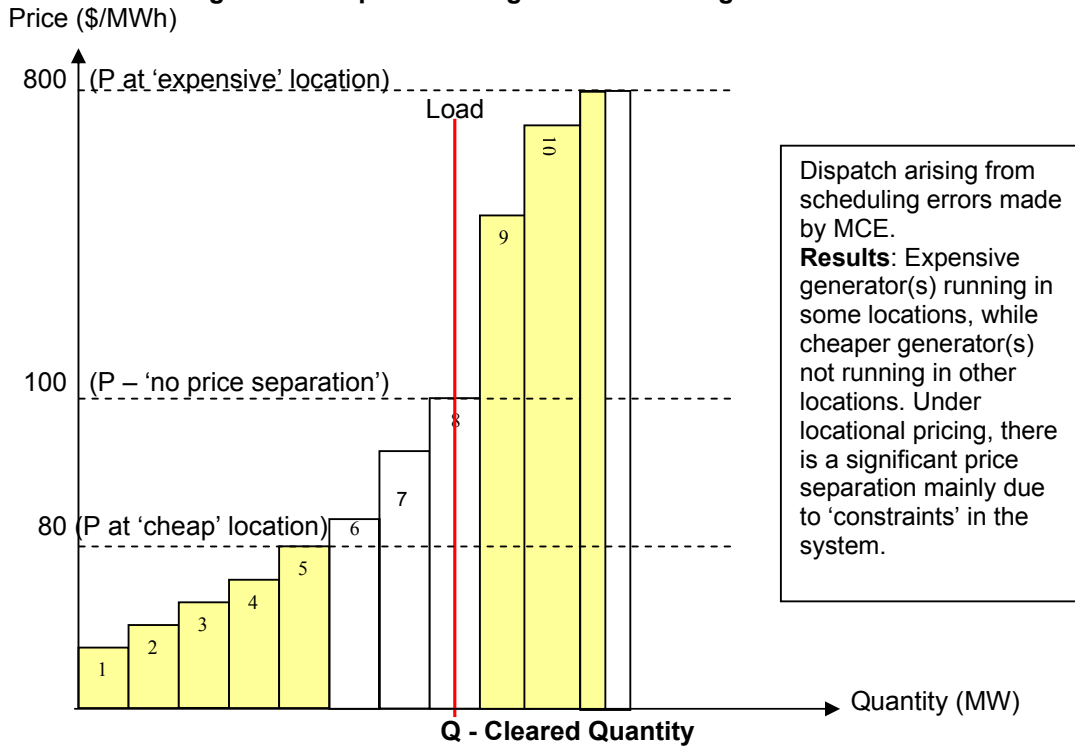
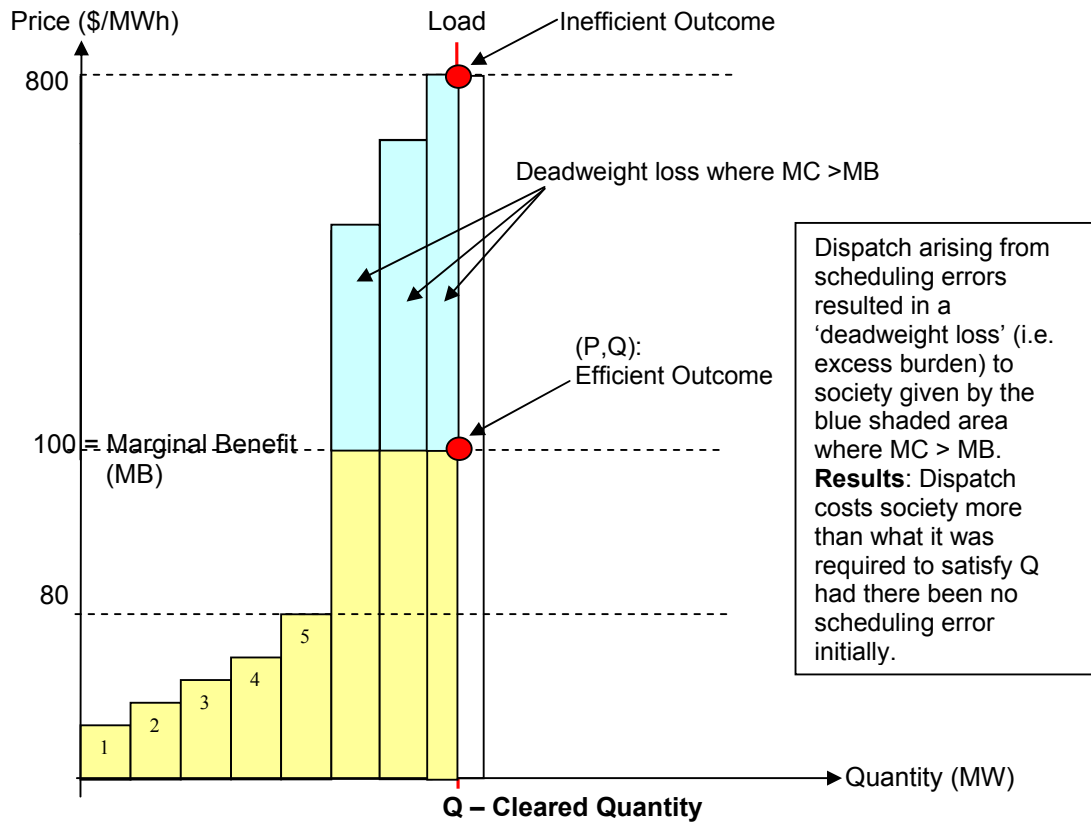


Figure 3 – Deadweight loss arising from dispatch with scheduling error



**References**

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2. Hunt, S. 2000. *Making Competition Work in Electricity*. New York: John Wiley & Sons, Inc.
3. Alfred, K., Peter, C., Robert, P., & Richard, D. 2003. *Pricing in the California Power Exchange Electricity Market: Should California Switch from Uniform Pricing to Pay-as-Bid Pricing?* A Blue Ribbon Panel Report prepared for a study commissioned by the California Power Exchange
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5. Bushnell, J. and S. Oren. 1994. Bidder cost revelation in electric power auctions. *Journal of Regulatory Economics* 6: 5-26.
6. Ethier, R., Mount, T., Schulze, W., Zimmerman, R. & Thomas, R. 1997. *Auction Design for Competitive Electricity Markets*. Working Paper, Cornell University. Presented at the HICSS Conference in 1997, Hawaii.

**ANNEX 6 Proposed rule modifications supported by majority of RCP (using Option 2)**

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...	...	...																	
3.3.1.5	- EMC and a market participant - EMC and a market support services licensee - PSO and a market participant - PSO and a market support services licensee	- request for compensation made under any of the following: - section 4.7.3 of Chapter 5 - section 5.4.3 of Chapter 5 - section 5.6.2 of Chapter 5 - section 7.7.3 of Chapter 5 - section 8.4.3 of Chapter 5 - section 8.6.2 of Chapter 5 - section 9.1.7 of Chapter 5 - section 9.7.3 of Chapter 5 - section 10.4.1 of Chapter 5 - <u>section 10.2.10 of Chapter 6</u>																	
<p>3.11.1 If a market participant or a market support services licensee (the "claimant") seeks compensation under section 3.3.1.5, the claimant shall submit its request to the EMC or the PSO. The request shall:</p> <p>3.11.1.1 meet the requirements of the relevant market</p>	<p>3.11.1 If a market participant or a market support services licensee (the "claimant") seeks compensation under section 3.3.1.5, the claimant shall submit its request to the EMC or the PSO. The request shall:</p> <p>3.11.1.1 meet the requirements of the relevant market</p>																		

Existing Rules (Release: 1 January 2006, read together with rule changes approved by the EMA as at 21 February 2006)	Proposed Rules (Deletions represented by strikethrough text and addition underlined)
<p>3.11.1.2 <i>manual</i> or the <i>system operation manual</i>; refer to the section of the <i>market rules</i> that the request is based on; and</p> <p>3.11.1.3 specify the amount of compensation sought.</p>	<p>3.11.1.2 <i>manual</i> or the <i>system operation manual</i>; refer to the section of the <i>market rules</i> that the request is based on; and</p> <p>3.11.1.3 specify the amount of compensation sought <u>(except where the request relates to compensation under section 10.2.10 of Chapter 6)</u>.</p>
<p><b>Chapter 6</b></p> <p>(No existing provision)</p>	<p><b>Chapter 6</b></p> <p><u>10.2.10</u> Where the <i>EMC</i> determines <u><i>settlement data</i></u> described in <u>section 10.2.1</u> pursuant to <u>section 10.2.3A.2, 10.2.5, 10.2.5A, 10.2.5B or 10.2.6</u>, a <u><i>market participant</i></u> with one or more <u><i>generation registered facilities</i></u> may seek compensation from the <u><i>EMC</i></u> in accordance with <u>section 3.11</u> of Chapter 3. For the purposes of <u>section 3.11.4</u> of Chapter 3, the <u><i>EMC</i></u> shall determine the relevant <u><i>claimant's</i></u> eligibility for <u>compensation and the amount of such compensation, if any, in accordance with Appendix 6K</u>.</p>

## APPENDIX 6K – COMPENSATION ARISING FROM MARKET ENERGY PRICE REVISIONS

### K.1 CALCULATING COMPENSATION AMOUNTS

K.1.1 For this section K.1, the following definitions apply:

$RMEP^m$  = revised *market energy price* (in \$/MWh) at *MNN* *m* for the relevant *dispatch period* determined by (i) re-running the *market clearing engine* pursuant to sections 10.2.3A.2, 10.2.5, 10.2.5A or 10.2.5B of this Chapter, or (ii) applying section 10.2.6 of this Chapter.

$IEQ^m$  = injection *energy* quantity (in MWh) for *GRF* *m* for the *settlement interval* corresponding to the relevant *dispatch period*.

$spq$  = index of a specific *price-quantity pair* in an *energy offer*.

$pq$  = index of a *price-quantity pair* in an *energy offer*, ordered by increasing price.

$Q^{m,pq}$  = quantity of a *price-quantity pair*  $pq$  for the *energy offer* for *GRF* *m* for the relevant *dispatch period*.

$P^{m,pq}$  = price of a *price-quantity pair*  $pq$  for the *energy offer* for *GRF* *m* for the relevant *dispatch period*.

$COMP^m$  = compensation payable in relation to the *energy offer* for *GRF* *m* for the relevant *dispatch period*.

K.1.2 Under this section K.1, where the *EMC* determines a revised *market energy price* for a given *dispatch period* by re-running the *market clearing engine* pursuant to sections 10.2.3A.2, 10.2.5, 10.2.5A or 10.2.5B of this Chapter, a *market participant* with a *generation registered facility* is eligible for compensation only if the *EMC* determines that (a) the quantity of *energy* scheduled for that *generation registered facility* based on its *real-time dispatch schedule* for that *dispatch period*, is more than (b) the quantity of *energy* scheduled for that *generation registered facility* for that *dispatch period* after re-running the *market clearing engine*. If a *dispatch instruction* for that *generation registered facility* for that *dispatch period* was issued by the *PSO* pursuant to section 9.1.2.2 of Chapter 5, then the *EMC* shall use the quantity of *energy* specified in that *dispatch instruction* for the purpose of section K.1.2(a) instead. The *PSO* shall provide such *dispatch instruction* to the *EMC* within three *business days* after the date of receipt by the *PSO* of a request for such *dispatch instruction* from the *EMC*.

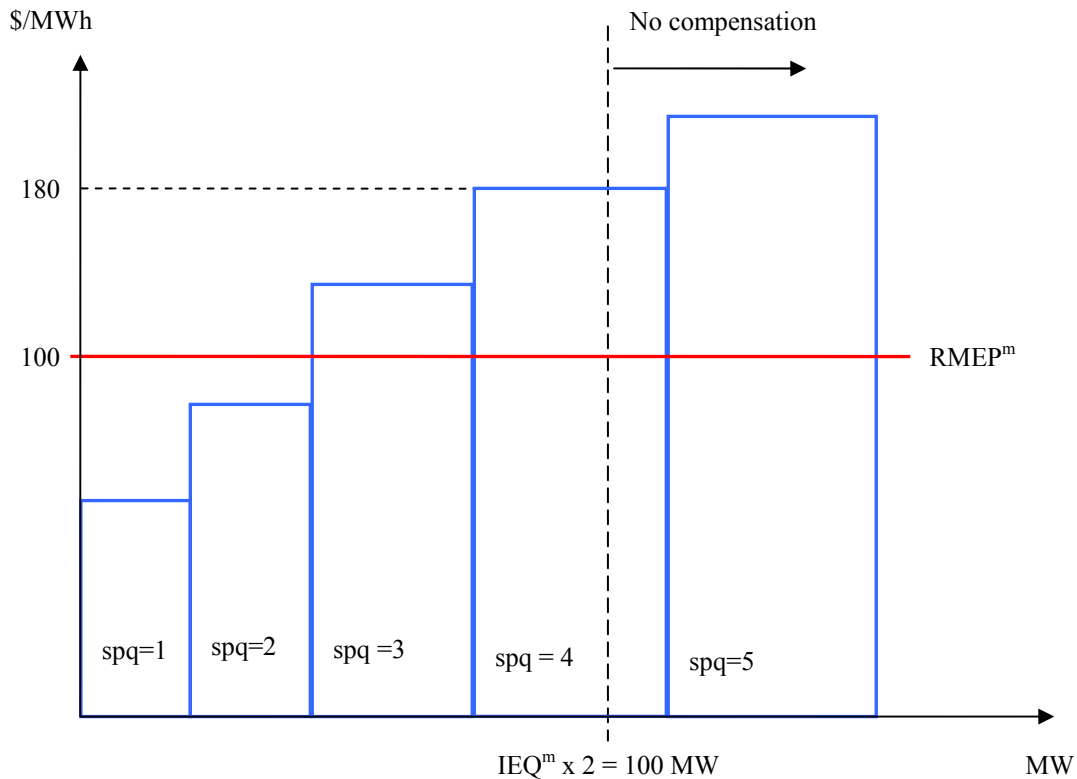
K.1.3 Subject to sections K.1.2, the compensation as described in section 10.2.10 of this Chapter for a *generation registered facility* of a *market participant* shall be calculated as follows:

$$\text{COMP}^m = \max\left[\left(P^{m,\text{spq}} - \text{RMEP}^m\right) \times \text{IEQ}^m, 0\right]$$

where:

$$\text{spq is such that } \sum_{pq=1}^{\text{spq}} Q^{m,pq} \geq (\text{IEQ}^m \times 2) \text{ and } \sum_{pq=1}^{\text{spq}-1} Q^{m,pq} < (\text{IEQ}^m \times 2)$$

**Explanatory Note – The following example illustrates the compensation calculation**



Suppose that a generation registered facility is eligible for compensation under section K.1.2 has an IEQ of 50MWh. Then, the compensation for that generation registered facility is determined as follows:

First, the specific price-quantity pair (spq) that corresponds to the actual energy produced by the generation registered facility in real-time is identified. This is the spq that simultaneously satisfies the following conditions:

$$\sum_{pq=1}^{spq} Q^{m,pq} \geq (IEQ^m \times 2) \quad \text{and} \quad \sum_{pq=1}^{spq-1} Q^{m,pq} < (IEQ^m \times 2) .$$

Diagrammatically, this is the spq where the vertical line representing the energy produced ( $IEQ^m \times 2$ ) intersects the energy offer stack of the generation registered facility. In this example,  $spq = 4$ .

Next, the price of that spq ( $P^{m,spq}$ ) is identified. In this example,  $P^{m,spq} = \$180/\text{MWh}$ .

Finally, this price, and the revised market energy price for the generation registered facility and its IEQ are used to calculate the compensation amount according to the following formula:

$$\text{COMP}^m = \max\left[\left(P^{m,\text{spq}} - \text{RMEP}^m\right) \times \text{IEQ}^m, 0\right].$$

**In this example,  $\text{IEQ}^m = 50\text{MWh}$ ,  $P^{m,\text{spq}} = \$180/\text{MWh}$  and  $\text{RMEP}^m = \$100/\text{MWh}$ . Hence, the compensation amount is:**

$$\begin{aligned}\text{COMP}^m &= \max\left[\$(180 - 100) \times 50, 0\right] \\ &= \mathbf{\$4,000}\end{aligned}$$

**(This amount is represented by half times the shaded area in the diagram above.)**

## ANNEX 7      **Comments from Senoko**

06 Mar 2006 18:55      HP LASERJET FAX



**CONFIDENTIAL**

6 March 2006

Energy Market Company  
9 Raffles Place #22-01  
Republic Plaza  
Singapore 348619

Attention: Teo Wee Guan

Dear Wee Guan

### **Compensation Arising from Using Revised MEP**

We refer to your rule change proposal S/No. 253 and thank you for inviting us to submit our comments.

This rule change highlights the quandary that occurs when the rerun energy price is lower than a GRF's (Generation Registered Facility) bid price. The rule change is proposed on the basis that ex-post price revisions are a regular feature of the Singapore electricity market. This is not the case and runs counter to the ex-ante design of the market.

### **The need for a rerun**

The NEM runs on an ex-ante basis. The dispatch schedule produced prior to the dispatch period is binding on the GRF and the EMC. Once the dispatch schedule has been produced and complied with by the market participants, the necessity for a rerun should only exist in exceptional circumstances.

On 11 November 2005, Senoko's PPB GT1 was called up to run for one period. Subsequently, a price rerun was conducted and the energy price payable to Senoko was lower than its bid price. The proposed rule change S/No. 253 has been drafted to deal with such a circumstance.

However, the rule change proposal must also address issues beyond that of compensation. The Rule Change Panel also needs to address the following:

- (a) Why was the rerun performed?
- (b) Under what circumstances should a rerun be performed? (The conditions must be clearly articulated for all market participants.); and,
- (c) Did such circumstances arise for P26 on 11 November 2005?

Results generated by the MCE (Market Clearing Engine), which are audited to conform to the market rules, should be relied upon. Conditions for reruns need to be clearly and explicitly specified to all market participants. Currently, the market rules are not explicit as to the specific conditions under which reruns can be conducted. The market rules currently seem to grant a great degree of flexibility to the EMC to



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06/03 '06 MON 18:54 [TX/RX NO 7168]

decide when a rerun is undertaken. In the interests of transparency and equity, any rerun must satisfy clearly stated criteria.

**The need to reinstate "Constraint-on" payment**

The only instance in which a price revision is necessary is during a "constraint-on" situation, which used to be recognised in SEP but does not exist in the NEM. During such situations necessitating a price revision, a constrained-on payment should be paid to the GRF.

"Constraint-on" payment was in place in the former Singapore Electricity Pool and should be reinstated to address constraint-on situations.

**Compensation amount**

EMC is proposing that the affected generating unit be compensated in a staggered manner, according to the respective bid prices for the price bands. This is not the industry norm because clearly, a market price has been set for the unit by the DPR (Despatch Run). All units dispatched are paid at the DPR, regardless of the price bands at which their bids were submitted.

We do not agree with the basis of calculation of compensation in Section K.2. The affected units should be compensated at the MNN price for the entire IEQ (injection energy quantity). This is consistent with the current settlement method where a GRF is paid at its MNN for the entire IEQ, regardless of its bid price bands.

In essence, the EMC should adhere to the norm and pay the GRF its MNN price. There is no difference whether or not there had been a price revision; GRFs should be paid based on its MNN price, not on a segmented basis.

**Conclusion**

In an ex-ante market, price revisions should not occur. The DPR serves as a binding contract between the GRF and the EMC; an ex-post price revision is tantamount to a breach of contract. This rule change is proposed on the basis that MCE reruns may cause a price revision to occur. We believe that if the ex-ante philosophy is adhered to, price revisions will not occur unless a constraint-on situation occurs.

The onus therefore is on the EMC to ensure that its market rules adhere to the ex-ante market design. Market rules should not be changed to address problems which arise because of deviation from the ex-ante market design.

In considering this rule change, we request the Rule Change Panel to examine, among other things, the following:

- (a) Under what circumstances can a rerun be performed, taking into account NEM's ex-ante market design; and,
- (b) Whether the "constraint-on" payment should be reinstated.

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We trust that our comments provide a clear outline of the issues that need to be considered in dealing with compensation arising from a rerun. We will be pleased to elaborate on our comments with the Rule Change Panel.

Yours sincerely,

A handwritten signature in black ink that reads "Roy Adair" with a horizontal line extending to the right.

ROY ADAIR  
PRESIDENT & CEO