MINUTES OF THE RULES CHANGE PANEL
33rd PANEL MEETING
HELD ON TUESDAY, 3 JULY 2007 AT 10.05AM
AT ENERGY MARKET CO. PTE LTD
9 RAFFLES PLACE #22-01
REPUBLIC PLAZA, SINGAPORE 048619

Present: Dave Carlson  Lim Ah Kuan
Robin Langdale  Tay Swee Lee
Michael Lim  Philip Tan Pei Lip
Dr. Daniel Cheng  Dallon Kay
Henry Gan  Francis Gomez
Koh Kah Aik

Absent with Kng Meng Hwee  Low Boon Tong
Apologies: Dr. Goh Bee Hua

In Attendance: Paul Poh  Poa Tiong Siaw
(EMC) Teo Wee Guan  Wang Jing

1.0 Notice of Meeting
The Chairman called the meeting to order at 10.05am. The Notice and Agenda of the meeting were taken as read.

2.0 Confirmation of Minutes of the 32nd Rules Change Panel Meeting
The Minutes of the 32nd Rules Change Panel meeting held on Tuesday, 8 May 2007 was tabled and taken as read.

There being no amendment, the Rules Change Panel unanimously accepted and approved the Minutes.
3.0 Summary of Outstanding Rule Changes

The Panel noted the contents of the paper.

4.0 Monitoring List

The Panel noted the contents of the paper.

5.0 Matters Arising

The Panel noted that the follow-up actions were completed on the matters arising as outlined, except for the following:

5.1 MCE Re-Run Relating to Type 4 Cases

At the 31st RCP Meeting, a panel member commented that price revision relating to Type 4 cases should be retained. He was concerned that consumers might end up paying higher prices should price revision relating to such cases be removed.

EMC was requested to assess the price impact on various parties had there been no such price revision by using historical data.

Based on historical data of 17 reruns, it was observed that:

- The price impact on consumers for most cases is not very significant. Even for the most severe case, no price revision would have resulted in an increase of about $4.25/MWh for consumers for that half hour period.

- There were a few periods where consumers actually paid more with price revision. In other words, they would be ‘better off’ if there is no price revision in those periods.

EMC maintained its original recommendation that re-run of MCE for Type 4 cases be removed from the rules. This is because constraints in MCE are precautionary in nature. Hence, they cannot be removed or relaxed (ex-post) simply because no untoward circumstance has occurred. It is both inefficient and inconsistent to charge ex-ante prices only if constraints prove ‘necessary’ in a period, ex-post.

EMC felt that a re-run is justifiable only if such cases involve an input error in the ex-ante MCE re-run (of which then such a case should belong to ‘Type 2 cases’).
EMC recommended that the RCP support the recommendation that price revision pertaining to Type 4 cases be removed.

Discussion by the Panel

The Panel was informed that Mr. Low Boon Tong from PowerSeraya wrote to EMC to suggest that the “re-run only be applied where CVP prices cause a material impact on market prices. The said material sum can be set in the rules and reviewed from time to time”.

Referring to the table illustrating the price impact on consumers and generators arising from price revision, Mr. Philip Tan asked EMC for the basis of computing the ‘Maximum (extra) amount that GRF would receive (or gained) had there been no re-run’ (under Column 6 of the table) and the ‘Maximum (extra) amount a GRF would have to pay (or lost) had there been no re-run’ (under Column 7 of the table).

Mr. Teo Wee Guan explained that:

(a) after the re-run, the revised MEP can turn out higher or lower than the original MEP;

(b) if the revised MEP turns out lower than the original MEP, then a generator would be ‘better off’ without the re-run if it has a positive IEQ. The ‘(original MEP – revised MEP)*IEQ’ would give the extra amount that generator would have earned had there been no re-run; Conversely, a generator would be ‘worse off’ without the re-run if it has a negative IEQ. The ‘(original MEP – revised MEP)*IEQ’ would give the extra amount that generator would have paid had there been no re-run;

(c) if the revised MEP turns out higher than the original MEP, then a generator would be ‘better off’ without the re-run if it has a negative IEQ (which means a generator has to pay). The ‘(original MEP – revised MEP)*IEQ’ would give the amount that generator would have saved had there been no re-run. Conversely, a generator would be ‘worse off’ without the re-run if it has a positive IEQ. The ‘(original MEP – revised MEP)*IEQ’ would give the amount that generator would have lost had there been no re-run.

In summary, Mr. Teo concluded the impact on individual generators (had there been no re-run) was not straightforward. It would depend on (1) whether the revised MEP turn higher or lower than the original MEP for a generator, and (2) whether that generator has a positive or negative IEQ.
Mr. Tan also asked EMC to explain the basis of computing the “MEP Difference (Original MEP – Revised MEP)” (under Column 5).

Mr. Teo replied that, for each affected period, there exist the original MEP (i.e. price for a generator before re-run) and the revised MEP (i.e. price for a generator after re-run). The price difference for a generator arising from a re-run is by taking the difference between the original MEP and revised MEP. A positive amount represents that the original MEP is higher than the revised MEP. Conversely, a negative amount means the original MEP is lower than the revised MEP. Because there are many MEPS and hence, many associated price differences for each period (i.e. Original MEP – revised MEP), EMC has chosen to give the maximum and minimum values of the price differences.

Mr. Tan sought clarification on the sample data derived on 6 Dec 2005 where the MEP difference and the max difference is $10.67, but he was puzzled as to why the amount involved was so small (i.e. $32.81). This would mean that the generator had generated about 3MWh.

To that, Mr. Teo confirmed that the data given was correct. For that affected dispatch period (P32), only one generation node experienced a big price separation (a difference of $10.67 by taking original MEP minus the revised MEP). However, that node had a very low IEQ. The rest of the generation nodes only experienced very small price differences after the re-run not exceeding $0.20.

Mr. Dallon Kay noted that the WEP price is not reflected as it is more appropriate for consumers’ reference price.

Mr. Paul Poh explained that WEP would involve the calculation of HEUC. However, EMC would not be able to calculate the original HEUC unless EMC re-performs a settlement run using non rerun data. Instead, EMC used an alternative approach based on the fact that any (extra) money amount generators would have received would mean the corresponding (extra) money amount consumers would have to pay. This approach is correct, and is as good as using WEP. This is because HEUC is a balancing component used to ensure the payout to creditors equals the money collected from debtors.

Mr. Henry Gan highlighted that a rerun for Type 4 will mute the price signal for grid operator and felt that this price signal is essential for grid planning purpose in a liberalized electricity market.

Mr. Frances Gomez asked, since there is a threshold in the Grid’s capacity, if it is possible to link the re-run to the actual line flow in real-time, i.e. only do a re-run if the actual line flow in real-time does not exceed the line capacity by a certain percentage tolerance. This ensures that price signals for significant line overload would not be removed.
Mr. Tay Swee Lee responded that doing that would be equivalent to having an ex-post market. In our ex-ante market, the latest cut-off time for the MCE to take into account market conditions should be ‘T-5 minutes’. If all inputs into the MCE are deemed to be correct as at ‘T-5minutes’, we should not have a re-run as a matter of principle.

The matter was put to a vote by the RCP members.

The following Panel members SUPPORTED EMC’s recommendation that price revision pertaining to Type 4 cases be removed.

Mr. Lim Ah Kuan                 Dr. Daniel Cheng
Mr. Tay Swee Lee              Mr. Koh Kah Aik
Mr. Michael Lim                  Mr. Robin Langdale
Mr. Henry Gan

The following Panel members DID NOT SUPPORT EMC’s recommendation and requested EMC to continue the re-runs with increased monitoring to control around what degree the line is overloaded before deciding whether to do a re-run.

Mr. Philip Tan
Mr. Francis Gomez

By majority of votes, the Panel supported EMC’s recommendation. Including the Panel’s decision on this matter arising, the Panel has supported all the recommendations made by the EMC in its ‘Review of price revision in SWEM’. The EMC will table the detailed proposed rule changes to the RCP for approval in due course.

6.0 Equity Between Generators and Interruptible Loads in Reserve Provision
(Paper No. EMC/RCP/33/2007/CP15)

The concept paper examined the equity between Generation Registered Facilities (GRFs) and Load Registered Facilities (LRFs) in Reserve position.

A Market Participant (MP) expressed concern that payments to GRFs and LRFs were inequitable given that LRFs have been activated for Reserve considerably less often than GRFs have.

As noted, GRFs and LRFs are different types of facilities and their responses differ in several aspects and different operational requirements also apply to each. Thus, Reserve provision by these two types of facility is not directly comparable.
The Panel was informed that EMC evaluated 3 options to address the issue:

1. to consider Reserve from GRFs and LRFs as different services
2. to alter the Reserve payment methodology
3. to adjust the Primary and Secondary Reserve activation frequencies of LRFs to bring about more balanced response between GRFs and LRFs in Reserve position

EMC assessed that Option 3 to be appropriate for consideration.

EMC requested the Panel to ask the PSO to review whether the current Primary and Secondary Reserve activation frequencies for LRFs can be raised to give LRFs an increased expectation of being activated during contingencies.

A Panel member has requested EMC to confirm with the New Zealand market and the ESB of Ireland the basis on which the number of IL activations is counted in these jurisdictions respectively.

The Panel agreed that as the PSO had expressed some serious concerns over this concept paper and since the PSO was unable to attend this meeting, the paper would be deferred to the next RCP meeting.

7.0 Mixed Integer Program Based Modeling of Regulation Constraints
(Paper No. EMC/RCP/33/2007/263(R))

The rule change proposal is to correct an error in section D.18.3.6 of Appendix 6D of Chapter 6 of the Market Rules. This rule has previously been approved by EMA but has not been implemented.

The Panel was informed that a rule transcription error was discovered when EMC verified the set of approved rules with the coding change of the MCE that is required for implementation. The error was found in the proposed formula in Section D.18.3.6 of Appendix 6D of Chapter 6 of the market rules. The Panel was asked to note that the “+” after Generation_{g(l)} should have been “-” instead.

The Panel supported EMC’s recommendation and to make the necessary recommendation to the EMC Board for adoption.

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1 Implementation was scheduled on 5 July 07. Implementation is deferred pending EMA approval of the correction
8.0 Re-Modeling Type 2 Artificial Lines  
(Paper No. EMC/RCP/33/2007/264)

This paper is to assess EMC’s rule modification proposal to re-model Type 2 Artificial Lines in the MCE to correct instances when nodal prices associated with “disconnected” generation units do not reflect the locational system marginal price. There could potentially be large settlement impact on such a unit if it is charged very high price (which does not reflect LSMP) for energy while it is on maintenance and drawing electricity for station load.

The Panel was informed that this rule change was an urgent modification made by the Urgent Rule Modification Committee on 27 January 2007.

The Panel was informed that the Market Clearing Engine employs locational marginal pricing that establishes nodal prices that reflect the system marginal price. Each nodal price should reflect the change in total system cost of serving incremental load at that node.

In Nov 2006, EMC began to observe nodal prices that do not reflect the locational system marginal prices for generation units that were artificially connected to the grid model by the MCE using Type 2 Artificial Lines.

EMC’s MCE consultants, PSC, traced the problem to the modeling of Type 2 Artificial Lines, which currently do not contain line flow/line loss points defined in the reverse direction. Hence, if there was a need to meet demand at an artificial node, the demand would not be able to be met from the system because no reverse flow can be channeled through Type 2 Artificial Lines. Therefore, higher-priced offer (that was not cleared) from the generating facility would have to be used or a “deficit generator” violation would be triggered (at price cap of $4,500) to meet the demand.

EMC proposed, where possible, that the PSO defines a default line, which would be an existing line, for each generating facility. When a generation facility is not physically connected to the system, artificially connect it with a Type 2 Artificial Line that has the electrical characteristics of the generation facility’s default line.

The Panel was also informed that the Technical Working Group (TWG) convened on 18 June 2007 to consider this proposal. The TWG noted the test results and given the positive outcome of the test results, the TWG unanimously endorsed the proposal.

The Panel supported EMC’s recommendation and to make the necessary recommendation to the EMC Board for adoption.
9.0 **Re-Modeling Type 1 Artificial Lines**  
(Paper No. EMC/RCP/33/2007/270)

This paper is to assess EMC’s rule modification proposal to re-model Type 1 Artificial Lines in the MCE to correct instances when nodal prices associated with fully-dispatched (for energy) multi-unit facilities do not reflect locational system marginal prices.

The Panel was informed that multi-unit facilities are combined cycled plants (CCP). The MCE models a CCP as a multi-unit facility first by artificially creating a CCP node. This CCP node is then connected to its constituent generating units with Type 1 Artificial Lines. At present, each Type 1 Artificial Line has a forward flow limit that is equal to the capacity of the constituent generating unit it is connected to.

PSC Consultants have explained that with such a setup, abnormally low nodal prices at a CCP node can occur (and has occurred) when the following conditions are met:

1. The CCP is fully dispatched for energy; and
2. In determining the CCP’s nodal price, the MCE calculates the change in system cost required for a decremental demand at the CCP node.

Here, a decremental demand would require energy to be “pushed out” from the CCP node to the grid. However, because the CCP is already fully dispatched for energy, the Type 1 Artificial Lines adjoining the constituent generating units would have been fully loaded. Hence, no additional flow can exit to the grid via these lines. The CCP node then becomes “separated” from the main system and hence the system marginal price. The CCP’s nodal price would then have to come from its offer, which could be lower than the system marginal price. This is not the intended outcome. The CCP’s nodal price should have been the system marginal price.

PSC proposed to increase the line limit of Type 1 Artificial Lines by a small margin to prevent such scenarios from happening. From the result of testing conducted, it is concluded that the proposed change effectively solves the pricing anomaly due to the line limits of Type 1 Artificial Lines being reached.

The Panel was also informed that the Technical Working Group (TWG) convened on 18 June 2007 to consider this proposal. The TWG noted the test results and given the positive outcome of the test results, the TWG unanimously endorsed the proposal.

The Panel **supported** EMC’s recommendation and to make the necessary recommendation to the EMC Board for adoption.
The Panel requested EMC to provide a written report from the TWG to the Panel for future recommendations.

EMC noted the Panel's request and will do as requested.

10.0 **Discretion to Revise/Revoke Margin Call Requirements in the presence of Manifest Error(s)**
(Paper No. EMC/RCP/33/2007/267)

The rule change proposal is to allow EMC to revise/revoke margin call requirements for a Market Participant (MP) or the MSSL in exceptional cases where that MP/MSSL has reasonable basis to believe that its Estimated Net Exposure (ENE) determined by EMC contains manifest error. Such error could be due to metering, human input or system calculation error.

A manifest error could lead to an unusually high estimated risk exposure for a MP/MSSL determined by the EMC. This may cause that MP/MSSL to be issued with a large margin call by the EMC. The issuance of such a large margin call may not be warranted had the error not occurred in the first place. However, existing rules do not give EMC the discretion to reassess the estimated risk exposure of a MP/MSSL and consequently, to revise/revoke a margin call that has already been issued.

**Proposed solution**

A MP/MSSL may request (with supporting materials and within the stipulated timeframe) for a reassessment of its ENE by the EMC if it has reasonable basis to believe that the removal of such manifest error(s) will result in:

a) that MP/MSSL's actual (i.e. reassessed) ENE being different from the ENE originally determined by the EMC by at least 10%; and/or
b) that MP/MSSL’s actual (i.e. reassessed) ENE not exceeding 70% of the credit support currently provided by that MP/MSSL.

After EMC’s reassessment, the EMC will inform (within the stipulated timeframe) that MP/MSSL of one of the following outcomes:

i. revoke the margin call issued to that MP/MSSL if the reassessed ENE does not reach seventy percent of the credit support currently provided by that MP/MSSL; or
ii. issue a revised margin call to that MP/MSSL if the reassessed ENE is either greater or lesser than the ENE originally calculated by the EMC by at least 10%; or
iii. take no further action if neither of the above-mentioned two conditions [i.e. (i) and (iii)] applies.
Where (ii) or (iii) above applies, the deadline which that MP/MSSL must satisfy its margin call requirements remains the same as that which applies to the original margin call (i.e. there is no extension of deadline and the deadline shall remain as the close of banking business of the bank at which the EMC’s bank accounts are held on the second business day following the date of the original margin call issued to that MP/MSSL, i.e. ‘D’ +2 business days).

The paper also proposed some changes to the definitions of ‘Current Exposure’, ‘Estimated Net Exposure’ and ‘Estimated Average Daily Exposure’ contained in the market manual. All these changes are made to more accurately reflect/capture the relevant exposures of a MP/MSSL.

Mr Koh Kah Aik commented that as the Meter Data Manager is currently also SP Services and that would mean SP Services would have quicker access to meter readings. Hence, there could be more lead time for SP Services to raise a request for reassessment, compared to other market players.

The Panel requested SP Services to study if it can have an earlier cut-off time for the submission of meter readings to market players (currently, the cut-off time is D+5 business days).

The Panel has also requested the EMC to study if it is possible to give market players more lead time by extending the deadline which applies to the original margin call issued by the EMC to a MP/MSSL.

Notwithstanding the two matters arising above, the Panel supported EMC’s recommendation and to make the necessary recommendation to the EMC Board for adoption.

There being no other matters, the meeting ended at 12.30pm with a vote of thanks to the Chair.

Dave E Carlson
Chairman

Minutes taken by:
Eunice Koh
Senior Executive - Corporate Secretariat