The Automatic Financial Penalty Scheme (AFPS) was introduced by the EMA in the Singapore Wholesale Electricity Market to incentivise compliance with dispatch schedules, thereby enhancing system reliability and stability. Since it was implemented in 2015, EMC has received feedback that a review of the scheme should be conducted.

This paper revisits the objective of the scheme and the considerations at its conception and examines three issues raised by Market Participants (MPs).

**Issue 1: Broaden Exemptions to the Penalty**

EMC assessed new cases suggested for exemption by MPs and proposes that:
- a) partial forced outage;
- b) de-loading and fail-to-sync due to forced outage; and
- c) generators that are on local control and responding positively to system disturbance be exempted from the penalty.

**Issue 2: Minimum Penalty Value**

EMC is of the view that at the minimum value of $5000, generators may not be incentivised by the penalty to minimise deviation from dispatch. We would like to propose for adoption, a lower penalty floor with higher penalty rates based on a tiered penalty structure.

**Issue 3: Treatment of Embedded Generator (EG) Must-run Quantity**

EGs have given feedback that their must-run quantity should always be given priority for dispatch, regardless of whether such quantity is intended for self-consumption. EMC suggests that EGs can choose to offer such must-run quantity at the price floor of -$4500 in order to secure dispatch and no changes are required.

The Rules Change Panel discussed the above issues at the 112th RCP meeting.
For Issue 1, the Panel unanimously supported that generators that are on local control and responding positively to system disturbance be exempted from the penalty. The proposed case for exemption relating to a) partial forced outage, b) de-loading and fail-to-synchronise due to forced outage is deferred. The Panel considered that for consistency, a decision should be deferred until EMC has obtained clarity from the EMA on how such events would be considered in the calculation of probability of failure/Expected Output Reduction Rate under the Intermittent Pricing Mechanism.

For Issue 2, the Panel requested EMC to seek clarification from the EMA on the intent of the current minimum penalty value before EMC starts to develop any new penalty model.

For Issue 3, the Panel by majority vote supported EMC’s recommendation that no change is required.
1. Introduction

The Automatic Financial Penalty Scheme (AFPS) was introduced in the Singapore Wholesale Electricity Market (SWEM) as part of EMA’s policy decision on “Review of Policy on Direct Supply of Electricity by Generating Sets to Onsite Loads”.

With the AFPS, EMC will impose financial penalties on Generation Registered Facilities (GRFs), which are subject to the PSO’s central dispatch, whenever they deviate from their schedules by more than 10MW.

Since the implementation of the scheme on 17 November 2015, EMC has received feedback from a number of generation companies (Gencos) that a review of the AFPS should be conducted to re-examine whether a GRF should be penalised under scenarios where deviation from dispatch is beyond the Genco’s control.

This paper seeks to clarify/revisit the objectives of the AFPS and assess if enhancements should be made to better reflect them.

2. Background

2.1 EMA’s policy decision on the AFPS

In 2010, EMA conducted a comprehensive review of its policy on “Direct Supply of Electricity by Generating Sets to Onsite Load” and made the decision to implement, among other things, the AFPS.

The AFPS is to provide for a penalty to be automatically imposed and collected from Gencos when their GRF(s) deviates from dispatch schedules. With this, the PSO need not refer, and the Market Surveillance and Compliance Panel (MSCP) need not conduct investigation into, straightforward non-compliance with dispatch.

**Deviating Generation Registered Facility**

Under the AFPS, penalties will be imposed on Gencos with deviating GRFs, which are those GRFs that have deviated from their dispatch schedules by more than 10MW, except for the following reasons:

- The GRF’s deviation is to help maintain the security or reliability of the power system
- The GRF’s deviation is out of the Genco’s control
- The GRF’s deviation is required/permitted under governing documents such as Transmission Code, Market Rules and System Operation Manual

Specifically, GRFs are exempted from the AFPS under the following scenarios (‘existing Exempted Cases’), as expressly provided for under section 3.7.3 of Chapter 5 of Market Rules:

a. The GRF is operating **under AGC** throughout the dispatch period,

b. The GRF is **issued dispatch instructions by the PSO** to deviate from its dispatch schedules and such instructions have been complied with,

c. The GRF is undergoing **re-commissioning tests** that have been approved by the PSO,

d. The GRF experienced a **forced outage** which **caused** the GRF to **automatically disconnect** from the transmission system. The GRF will be exempted from AFPS for that dispatch period and the dispatch period after,

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1 Other determinations include a) shifting grid charges to a fixed charging regime, b) net treatment of non-reserve charges for embedded generators, c) Gross bidding of Embedded Generators, and d) Non-Frequency Responsive (NFR) cap. Please refer to EMA’s determination paper for more details.
e. The GRF is being **started up or shut down**. For the avoidance of doubt, if a GRF fails to synchronise, it is not considered as being started-up and thus not exempted from the AFPS, and

f. The GRF is performing **fuel changeover** as required under the Transmission Code.

In addition to the above exemptions, Gencos can appeal to the MSCP for a refund of the penalty if they can subsequently demonstrate that compliance with the dispatch schedules would endanger the safety of any persons, substantially damage equipment, or violate any applicable law.

**Penalty value and collection**

The penalty value for a deviating GRFs for any given dispatch period is, in effect, set at the rate of 0.5 x (USEP+HEUC) for each MW of deviation from its schedule (in excess of 10 MW), subject to a minimum of $5000, as determined in accordance with the formula below:

\[
\text{Financial Penalty} = \max\left(2 \times (\text{USEP} + \text{HEUC}) \times \left(\frac{1}{2} \times |\text{EndScheduledQty} - \text{EndGeneration}| \times 0.5 \text{ hour} - 2.5 \text{ MWh}\right),$5000\right)
\]

where:

- \(\text{EndGeneration}\) is the GRF’s gross generation output (in MW) at the end of a dispatch period
- \(\text{EndScheduledQty}\) is the GRF’s scheduled output (in MW) for a dispatch period

EMC will issue the preliminary and final financial penalty statement on the 6th and 10th business day after the trading day respectively, and will collect the penalty from the MPs on the 20th calendar day after the trading day through direct debit from the Genco’s bank account.

The penalty collected from AFPS will be paid to consumers via the Monthly Energy Uplift Charge (MEUC).

2.2 **Previous Industry’s comments on the AFPS**

Before the AFPS was implemented, the draft rules were published for industry comments, during which MPs have expressed their views that deviation from dispatch arising from the following scenarios should also be exempted from penalty:

- Occurrence of partial outage/load run-back due to forced outage, where there is no tripping of the GRF in the given dispatch period;
- Deviations due to gas supply issues but no fuel-changeover were required;
- Deviation by multi-shaft units registered as two separate GRFs, where the tripping of one GRF causes the other GRF to deviate; and
- From Waste-to-Energy Plants.

EMA considered the comments and determined that there is no justification to exempt such deviating GRFs in the above scenarios. Details of EMA’s response are published on the EMC website.\(^3\)

2.3 **Request from Industry to Review the AFPS**

After the AFPS was implemented in November 2015, EMC received feedback from various MPs to review this scheme.

The industry called for the review of the AFPS in these three main areas:

\(^2\) The MW deviation is measured by the absolute difference between the energy schedule (MW) and the actual generation output level at the end of dispatch period as captured by PSO’s Energy Management System.

\(^3\) Please refer to [https://www.emcsg.com/f127.93629/Reply_to_Industry_Comments_on_APS-final.pdf](https://www.emcsg.com/f127.93629/Reply_to_Industry_Comments_on_APS-final.pdf)
- **Broaden Exemptions to the Penalty**—the existing Exempted Cases are not comprehensive enough to cover all scenarios where the AFPS should not apply. Several new cases have been suggested by MPs to be added to the Exempted Cases;

- **Review of Minimum Penalty**—a review of the minimum penalty value should be undertaken; and

- **Review treatment of Embedded Generator (EG ⁴)’s “must-run” quantity**—the requirements imposed should be changed to better reflect EG’s must-run nature.

These three issues will be examined in detail in section 3 of this paper.

3. **Review of the AFPS**

3.1 **Broaden Exemptions to the Penalty**

3.1.1 **Objectives of the AFPS**

The objective of the AFPS is to incentivise generators to comply with dispatch schedules and therefore reduce the need for the PSO to manually intervene with schedules, thus maintaining system security and dispatch optimality. Meanwhile, it is also acknowledged that deviation caused by events which are out of Gencos’ control should not be penalised.

Therefore, when reviewing whether additional cases should be exempted, the following criteria apply:

a. If the deviation is to help maintain system security and reliability, it should not be penalised;

b. If the deviation is due to reasons out of the Genco’s control and the Genco is not the best party to manage the risk, it should not be penalised under AFPS; and

c. If there is another mechanism in place that provides more effective deterrence to the deviation, it should not be penalised under AFPS.

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⁴ In the context of this paper, all references to EGs refer to embedded generators that are registered as GRFs. EGs that are Generation Settlement Facilities are not subject to dispatch and thus not subject to AFPS.
3.1.2 Analysis of Proposed Cases for Exemption

EMC has consulted the industry on what other cases should be considered for exemption from penalty. The proposed cases and EMC’s assessment are detailed in Table 1.

Table 1: Additional Cases for Exemption proposed by MPs

<table>
<thead>
<tr>
<th>No.</th>
<th>Proposed Case for Exemption</th>
<th>Reasons Provided by the MP</th>
<th>EMC’s Assessment</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Forced outages that do not necessarily result in automatic disconnection from the grid, including:</td>
<td></td>
<td>Should be exempted and considered as a forced outage in the GRF’s SPF calculation</td>
</tr>
<tr>
<td></td>
<td>a. the period before the tripping where the GRF may already be de-loading;</td>
<td></td>
<td>De-loading and failure to synchronise do pose risk to the safe and reliable operation of the power system. Gencos are the best parties to manage such risks (by properly maintaining their plants).</td>
</tr>
<tr>
<td></td>
<td>b. de-loading due to operating issues;</td>
<td></td>
<td>However, if de-loading and failure-to-sync is caused by a forced outage (that is out of the Genco’s control), then such cases should be exempted similar to the Existing Exemption for forced outages.</td>
</tr>
<tr>
<td></td>
<td>c. failure or delay in synchronisation ('failure-to-sync'); and</td>
<td></td>
<td>Furthermore, under some scenarios, the de-loading or load run-back could be required to prevent GRFs from tripping, which would otherwise cause greater risk to system operation. Hence, it is reasonable to exempt such cases to encourage GRFs to maintain reliable operation during such events.</td>
</tr>
<tr>
<td></td>
<td>d. partial forced outage, e.g. tripping of one of the generating units within a multi-unit facility.</td>
<td></td>
<td>Similarly, failure-to-sync, if can be proven to be due to forced outages out of the Gencos’ control, should also be exempted.</td>
</tr>
</tbody>
</table>

5 CP26: Review of SPF Methodology. Please refer to Annex 1 for the proposed changes to the SPF methodology.
<table>
<thead>
<tr>
<th>No.</th>
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<td></td>
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<td>would factor in de-loading and failure-to-sync cases into a GRF’s SPF calculation (i.e. increase a GRF’s SPF). This is also in line with the SPF methodology stated in EMA’s determination paper on “Intermittency Pricing Mechanism”, where partial forced outage will count towards the SPF.</td>
</tr>
</tbody>
</table>
| 2   | Gas supply related issues including: | Gas supply could be disrupted by the supply source or due to transportation or distribution network failure which are beyond the control of Gencos. | Should be exempted and already covered under Existing Exempted Cases. 

The Transmission Code does not contain explicit provisions on the scenarios that would warrant a fuel change-over. Assuming that the PSO will monitor the gas system situation and override GRFs’ schedules in real-time where necessary, the GRFs should follow the PSO’s instructions. If doing so causes the GRFs’ output to deviate from its scheduled quantity, this falls under the existing Exempted Cases and no additional exempted cases are required.

Should not be exempted. 

With regards to a GRF’s reduced capability when running on back-up fuel, a Genco should know its GRFs’ maximum capacity when running on back-up fuel and have revised its offer quantities to correctly reflect its physical capacity. Therefore, it should not be exempted. |
|     | a. Reduction in GRF’s output in response to gas system stress |                                | |
|     | b. Reduction in GRF’s output when running on back-up fuel |                                | |
| 3   | Testing as required/approved by the PSO |                                | Should be exempted and already covered under existing exempted case. 

GRFs/Generation Licensees might be required under the |

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6 Termed as EORR in determination paper on “Intermittency Pricing Mechanism”

7 However, this may breach gate closure therefore it can be explored whether exception should be given for such cases.
<table>
<thead>
<tr>
<th>No.</th>
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<th>Reasons Provided by the MP</th>
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</tr>
</thead>
</table>
|     |                             |                           | market rules, SOM and the Transmission Code to carry out various tests such as ancillary services capability testing and testing required under the emergency restoration plan. During such tests, it is possible that the GRFs may not be able to perform as expected and could deviate from their dispatch schedules.  

However, under the Market Rules, Gencos are already required to seek the PSO’s approval for such test plans and to inform the PSO of the possible impact on the system. The PSO should have taken any necessary preventive steps and the risks to the system should have been minimised. Further, it is reasonable to believe that the deviation is not intentional. Also, the objective of such tests is for the benefit of the market, e.g. (allowing more GRFs to provide ancillary services, ensuring GRFs can perform during emergency). Therefore, such cases should be exempted. |
| 4   | GRFs that are on Local Governor Control and Load Frequency Control (LFC) | The generation output of GRFs on local governor control and LFC are affected by system frequency. During system disturbance, there may be a significant change in generation output contributed by the LFC responding to system frequency, which should be exempted from AFPS as such deviation is not within the control of the Genco. | Should be exempted if it is responding positively to system disturbance  

Whether or not switching to load frequency control is under PSO’s instruction, generators on load frequency control would still respond to system frequency deviations and help restore frequency back to normal. Hence it is contributing to maintaining system reliability and thus should not be penalised.  

However, if deviation happens during periods where there is no significant system frequency fluctuation, the deviating GRFs should not be exempted from penalty. |
<p>| 5   | Waste-to-Energy (WTE) generators | WTE plants are primarily designed for incineration of solid waste and are not able | We do not recommend a blanket waiver for all WTE plants as this |</p>
<table>
<thead>
<tr>
<th>No.</th>
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</tr>
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<tbody>
<tr>
<td></td>
<td></td>
<td>to regulate or control its electricity generation within a narrow margin for the following reasons:</td>
<td>would eliminate any incentive for them to control plant output.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>a) WTE plants are mass burn incinerators (i.e. wastes are incinerated as they are received in the plant and large variation in the calorific value of waste are encountered on a continuous basis). For example, the characteristics of waste from the domestic sector differ greatly from waste generated by the industrial sectors. This results in the inability for the WTE plant to accurately forecast the steam flow (i.e. proxy to forecast the electricity generation amount).</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>b) The combustion cycle (i.e. for fuelling waste to the furnace and time for complete combustion) takes about 2 hours. Besides variation in the calorific value of waste, the long combustion cycle also makes it difficult to accurately forecast the steam flow as there is a delay in the response time between fuelling more waste into the furnace and achieving/not achieving the desired steam flow values.</td>
<td></td>
</tr>
<tr>
<td>6</td>
<td>EMC’s system is down</td>
<td>During EMC’s system maintenance, offer submission may be unavailable, and Gencos are unable to revise offers for GRFs which are facing technical issues to reflect their revised capability. As a result, the real-time/short term schedules may not be feasible for such GRFs.</td>
<td>There is no need for an additional exempted case.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Typically, EMC will inform the industry of the system maintenance and the period of time where the system is not available. During this downtime, GRFs should follow the most recent short-term schedules. If a GRF faces technical issues and its maximum capacity is de-rated, the Genco, knowing the EMC’s system is not able to process any offer variation, should inform the PSO promptly of the revised capacity. The PSO, in real-time, should issue a new dispatch instruction to that GRF based on its de-rated capacity.</td>
<td></td>
</tr>
<tr>
<td>No.</td>
<td>Proposed Case for Exemption</td>
<td>Reasons Provided by the MP</td>
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<tr>
<td>7</td>
<td>GRF’s actions due to environmental issues beyond GRF’s control</td>
<td>For example, air emission or seawater conditions. For example, in the case of Tuaspring’s desalination plant that is co-located with the GRF, the GRF may encounter operational restrictions if there is need to alter operations of the seawater cooling pumps in the event of oil spills within the vicinity of the facility’s seawater intake system.</td>
<td>Should not be exempted</td>
</tr>
</tbody>
</table>

**Exempted Cases to be set out in SOM instead of the Market Rules**

The list of exempted cases is currently stipulated under section 3.7.3 of Chapter 5 of the Market Rules. EMC has received feedback that the list of exempted cases should be transferred from the Market Rules to the SOM given that these cases are operational in nature and need to be assessed by the PSO.

**3.2 Review of the Minimum Penalty Value**

The penalty rate was initially proposed by EMA at $10,000/MWh without any price floor or reference to the prevailing spot prices. After assessing the industry’s feedback, EMA subsequently determined that the penalty rate is changed to $2 \times (USEP+HEUC)$ per MWh of deviation with a minimum penalty of $5000 per deviating GRF for a dispatch period.

Given the recent price trend, where $(USEP+HEUC)$ hover around $100$/MWh (on average $111$/MWh for year 2018), a floor of $5000 per dispatch period means that a deviation of 10.1 MW will incur the same penalty as a deviation of 100 MW. This outcome is not commensurate with the vastly different impact on the power system under these two scenarios. An MP has proposed that the minimum penalty value of $5000 should be reviewed and reduced (for example, to $10 \times (USEP+HEUC)$).

**EMC’s Assessment**

We agree that with the recent low market clearing prices, the penalty floor of $5000 may not provide adequate incentive for GRFs to minimise their deviations once they foresee that the magnitude of their deviation will exceed 10 MW. Meanwhile, we recognise that without a minimum penalty value, the current low price environment means that the AFPS might not sufficiently deter GRFs to adhere to their schedules.

Therefore, we recommend the following changes to the penalty value:

a. Remove (floor at 0)/lower the penalty floor so that the penalty value would be more reflective of the impact caused by a deviating GRF to the system;

b. Allow for a higher penalty rate in order to sufficiently deter GRFs from deviation; and

c. Apply a tiered penalty rate structure on deviating GRFs, where GRFs with greater deviations will be imposed a heftier penalty rate.
3.3 Review of the Treatment of Must-run Quantity

3.3.1 Background

EGs are on-site generation facilities that primarily supply electricity for their own consumption. In 2010, EMA made the determination that EGs (that are GRFs) will be required to bid into the market only for their export quantities. As for the quantities generated for their own use, EGs only need to declare to EMC and PSO ex-ante. The quantity generated for EGs’ own use (“declared quantity”) will be treated as “must-run” quantities in the market clearing engine and given priority in dispatch.

At the implementation level, the “declared quantity” is still treated as part of its energy offer, except that the MCE will automatically assign a very low default offer price to it. The priority in dispatch is given in the MCE by the difference between this default offer price and the lowest offer prices commercial generators are allowed to offer at. Currently, the default offer price for such “declared quantities” is set at -$4750/MWh, which is lower than the offer price floor (-$4500/MWh) set for normal energy offers. Therefore, all else being equal, “declared quantity” will have the highest priority in energy dispatch among all energy offers.

The 2010 determination, and correspondingly the market rules, require that the “declared quantity” which can be given priority in dispatch must be for EG’s own consumption only. Any residual quantities of generation that is intended to be exported to the grid are to be offered separately, where the offer price must be within the price limits of -$4500/MWh to $4500/MWh. The MCE will then compare this offer price with offers from other generators and determine whether this export quantity will be scheduled. Such an arrangement is intended to ensure fair competition among generators that intend to serve the pool.

The requirement for EGs to declare the quantities generated for their own use was implemented in June 2011. In November 2015, this rule was reinforced by explicitly requiring EMC to report to the MSCP if the EG’s “declared quantity” exceeds the quantity generated for its self-consumption by more than 10MW.

3.3.2 Issue faced by EGs

Must-run quantity greater than Self Consumption

Most EGs claim that they tend to have minimal flexibility in operating their generating units. Their total generation output is usually determined by the plant’s other business needs, for example, the demand for steam by its own plant or its customers. As the core business of most EGs is not to sell electricity and they cannot (afford to) vary their generators’ output in response to market conditions, the total output from their generators, whether self-consumed or exported to the grid, to EGs, is the “must-run” quantity that the EGs need to operate at and secure dispatch for.

On the other hand, the prevailing rules require that the “declared quantity”, which is accorded priority in dispatch, be restricted to the quantity generated for self-consumption. Nevertheless, the EG’s associated loads can comprise numerous electricity-consuming components and the consumption can fluctuate and sometimes fall below its “must-run” quantity. In such a scenario, the EG is required to submit a normal energy offer for the export quantity. If the EG had declared the whole “must-run” quantity under “declared quantity”, it will constitute a rule breach and a financial penalty may be imposed by the MSCP.

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9 In Chapter 6 sections 5.2.5B and 5.2.5C, added in EMA Directive RC322: Rules Modification for EMA’s Decision on Automatic Penalty Scheme (https://www.emcsg.com/f127.105371/EMC322-EMA-WJ.pdf)
3.3.3 EMC’s Assessment of the Treatment of “Must-Run” Quantity

The provision for “must-run” quantity was introduced out of the following considerations:

- Operational constraints create little flexibility for an EG’s generation level. An EG therefore needs dispatch certainty to ensure that it can generate at its desired generation level; and

- Level the playing field for all generators that export to the grid and serve external load. If an EG has excess electricity to export to the grid, it should then compete with other commercial generators on a level playing field. Therefore, any EG export quantity is not given special priority in dispatch.

We are of the view that the above considerations are still valid. Therefore, the existing requirements should remain.

In practice, EGs are able to ensure dispatch certainty even when their actual consumption fall below their “must-run” quantities. An EG can submit a normal energy offer for the whole “must-run” quantity at the normal price floor of $4500/MWh. As $4500/MWh is the lowest possible normal offer price for energy, such an offer will already have very high priority for energy dispatch. Based on historical data, the chance is slim that energy offers priced at the floor price of $4500/MWh will not be cleared. This provides sufficient certainty to EGs that their full desired generation level will be dispatched.

4. Consultation

The concept paper was published for consultation on 14 October 2019. Comments were received from the PSO, Senoko Energy, Keppel Merlimau Cogen, PacificLight Power, Senoko Waste-to-Energy and Keppel Seghers Waste-to-Energy. Please refer to Table 2 for the industry’s comments and EMC’s response.

Table 2 Industry Comments and EMC’s response

<table>
<thead>
<tr>
<th>Item No.</th>
<th>Industry Comments</th>
<th>EMC’s Responses</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>PacificLight Power’s Comments</td>
<td>EMC notes PLP’s support on the proposed exempted cases and suggestion for the SPF methodology to be implemented after IPM.</td>
</tr>
<tr>
<td>1</td>
<td>3.1.2 Analysis of the Proposed Cases for Exemption</td>
<td>PLP supports the proposal to broaden exemptions to the penalty and agrees with the proposed cases for exemption set out in Table 1 of the paper. We are however of the view that such exemptions should only be introduced after EMA’s paper on “Intermittency Pricing Mechanism” (IPM) has already taken effect. In EMA’s Final Determination Paper dated 30 October 2018, it states under Section 4.9.1 that IPM is projected to take effect around 2020. As such, any revision in the SPF methodology is not necessary in the interim given that IPM is already set to be implemented.</td>
</tr>
<tr>
<td>2</td>
<td>3.2 Review of the Minimum Penalty Value</td>
<td>PLP proposes that any review of the penalty rates should only be carried out after the implementation of the IPM.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>EMC notes PLP’s comments.</td>
</tr>
<tr>
<td>Item No.</td>
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<tr>
<td></td>
<td><strong>3.1.2 De-loading, partial forced outage</strong></td>
<td>EMC recognises that de-loading in such cases can serve to protect the plant from tripping and reduces the risk to the system. Therefore, it is proposed for such cases to be exempted from AFPS.</td>
</tr>
<tr>
<td>3</td>
<td>Senoko Energy's Comments</td>
<td>Counting such de-loading event towards the SPF is a factual reflection of the plant’s reliability at the time the incident happened and is not intended as an additional penalty. We consider it fair that since a de-loading event negatively impacts reliability regardless of the circumstances, it should be taken into account in the allocation of reserve cost.</td>
</tr>
<tr>
<td></td>
<td>3.1.2 Failure-to-sync</td>
<td><strong>We note the concern on the potential consequence that MPs may delay offer revision. The rules can be drafted such that partial outage is only to be exempted from AFPS for no more than two periods to encourage MPs to revise offer(s) promptly.</strong></td>
</tr>
<tr>
<td>4</td>
<td>Senoko Energy's Comments</td>
<td>Failure to sync due to unforeseeable technical issues are proposed to be exempted.</td>
</tr>
<tr>
<td></td>
<td>3.1.2 Back-up Fuel Switch</td>
<td>We would like to clarify that only fail-to-sync due to unforeseeable technical issues are proposed to be exempted.</td>
</tr>
<tr>
<td>5</td>
<td>Senoko Energy's Comments</td>
<td>We recognise that fail-to-sync due to unforeseeable situation is difficult to prove. Given that this is expected to be a rare occurrence, we can consider drafting this as ground for appeal to the MSCP.</td>
</tr>
</tbody>
</table>

**EMC's Responses**

EMC recognises that de-loading in such cases can serve to protect the plant from tripping and reduces the risk to the system. Therefore, it is proposed for such cases to be exempted from AFPS.

Counting such de-loading event towards the SPF is a factual reflection of the plant’s reliability at the time the incident happened and is not intended as an additional penalty. We consider it fair that since a de-loading event negatively impacts reliability regardless of the circumstances, it should be taken into account in the allocation of reserve cost.

We note the concern on the potential consequence that MPs may delay offer revision. The rules can be drafted such that partial outage is only to be exempted from AFPS for no more than two periods to encourage MPs to revise offer(s) promptly.

Failure to sync due to unforeseeable technical issues are proposed to be exempted.

We would like to clarify that only fail-to-sync due to unforeseeable technical issues are proposed to be exempted.

We recognise that fail-to-sync due to unforeseeable situation is difficult to prove. Given that this is expected to be a rare occurrence, we can consider drafting this as ground for appeal to the MSCP.

We note the concern on the potential consequence that MPs may delay offer revision. The rules can be drafted such that partial outage is only to be exempted from AFPS for no more than two periods to encourage MPs to revise offer(s) promptly.

Failure to sync due to unforeseeable technical issues are proposed to be exempted.

We would like to clarify that only fail-to-sync due to unforeseeable technical issues are proposed to be exempted.
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</tr>
</thead>
<tbody>
<tr>
<td>6</td>
<td>time and gate closure for revising offers would need to be taken into consideration. GRFs should be given a reasonable amount of time to rebid new plant capability after the fuel changeover.</td>
<td>fuel changeover is initiated due to MP’s own assessment, the MP can do so within gate closure to reflect its actual capability. Subsequently, the MP should respond as such to the MSCP for such gate closure violation.</td>
</tr>
<tr>
<td>6</td>
<td>3.1.2 Required Tests</td>
<td>We note that there could be different scenarios of tests. As much as possible, this concept paper is intended to define categories.</td>
</tr>
<tr>
<td>7</td>
<td>3.1.2 Proposal for Exempted Cases to be set out in SOM instead of the Market Rules</td>
<td>We note Senoko’s comments.</td>
</tr>
<tr>
<td>8</td>
<td>3.2 Review of the Minimum Penalty Value</td>
<td>We are of the view that a minimum penalty amount of $5000, coupled with the current penalty rate (with current average (USEP+HEUC) below $100), do not provide sufficient incentives for MPs to minimise deviation in many circumstances. Specifically, the penalty would be the same for all deviations between 10.1MW and 110 MW. We therefore propose that the penalty floor of $5000 be lowered/removed and a tiered penalty rate be applied. This would reduce a generator’s indifference to deviating between 10.1MW and 100MW and allow the penalty amount to be more reflective of their impact on the system.</td>
</tr>
</tbody>
</table>

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Keppel Merlimau Cogen’s Comments

9 3.1.2 Failure-to-sync

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Based on record from 2015 to 2018, the penalty value was at $5000 for 80% of the periods where AFPS was imposed, where MW of deviation ranged from 10.02MW to 206.16MW.
<table>
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<tr>
<td></td>
<td>There is no justification to penalize GRFs for failure to synchronize or de-loading in the same manner as a forced outage, as the system risk imposed by a forced outage is different from the system risk imposed by failure to synchronize or de-loading. Unlike a GRF that trips immediately, a GRF that de-loads to a stable load to prevent a forced outage will help to stabilize the system. Keppel disagrees that de-loading or failure to synchronize should be used in calculating Standing Probability of Failure.</td>
<td>EMC recognises that de-loading in such cases can serve to protect the plant from tripping and reduce the risk to the system. Therefore, it is proposed such cases be exempted from AFPS. Counting such de-loading event towards the SPF is a factual reflection of the plant’s reliability at the time the incident happened and is not intended as an additional penalty. We consider it fair that since a de-loading event negatively impacts reliability regardless of the circumstances, it should be taken into account in the allocation of reserve cost.</td>
</tr>
<tr>
<td>10</td>
<td><strong>3.2 Review of the Minimum Penalty Value</strong></td>
<td>We are of the view that a minimum penalty amount of $5000, coupled with the current penalty rate (with current average (USEP+HEUC) below $100), do not provide sufficient incentives for MPs to minimise deviation in many circumstances. Specifically, the penalty would be the same for all deviations between 10.1MW and 110 MW. We therefore propose that the penalty floor of $5000 be lowered/removed and a tiered penalty rate be applied. This would reduce a generator’s indifference towards deviating between 10.1MW and 100MW and allow the penalty amount to be more reflective of their impact on the system.</td>
</tr>
<tr>
<td></td>
<td><strong>Keppel Seghers and Senoko Waste-to-Energy’s Comments</strong></td>
<td></td>
</tr>
<tr>
<td>11</td>
<td><strong>3.1.2.5 Waste-to-Energy Generators</strong></td>
<td>We note the difficulties that WTE plants face. However, we are of the view that WTE plants are still the best party to manage such risks. WTE plants are encouraged to monitor the refuse level closely and avoid running into such situations.</td>
</tr>
</tbody>
</table>

KSES WTE plants (SWTE & KSTP) feels that de-loading due to refuse characteristic should be taken into account as an additional exemption for AFPS if a general blanket waiver will not be granted.

In Gas-to-Energy-Power plant, the NCV is constant and the MWh generation can be easily compensated by ramping up and down with the burners. In the context of WTE plant however, the source of fuel is mainly the municipal waste with varying refuse characteristics and with varying NCV. Hence, the steam flow production will fluctuate and in turn affect the power generation. Due the combustion nature of the municipal waste, there is no way to ramp up and down the MW within a short periods of 30 mins to within +/- 10MW.
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<td></td>
<td>As discussed, one of the classic example is the case happened in SWTE on 28 Aug 2018 (refer to attached boiler and TG steam flow trend for the incident). This is an operational challenge for WTE plants to adjust the parameters and expect result within the trading periods even with immediate VO as the steam flow can be erratic to predict. This is a genuine case study encountered by SWTE and may also potentially be faced by other WTE plants. The rationale here is that in general, the industry is facing a lack of refuse situation and the WTE plants are often running with a lower than average bunker level. We attribute that the situation may be a result of successful recycling programme as the nation is advocated on the idea of zero waste. With the 6th WTE plant starting operations soon and the new Tuas Nexus coming into the masterplan, we foresee that the steam flow fluctuation (due to lack of refuse) situation may be more prevalent in the future as the plants need to share the limited refuse resources. Likelihood of refuse with lower NCV can be high when operating at low bunker level.</td>
<td></td>
</tr>
<tr>
<td>PSO's comments</td>
<td></td>
<td></td>
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<tr>
<td>12</td>
<td>EMC should explain why there is a need to review the AFPS by providing data on the number of AFPS cases, which facility and amount of penalty collected. Records should cover since AFPS was implemented to see any trend.</td>
<td>The review was initiated by MPs as part of the RCP workplan prioritisation. It was ranked as being of high importance and urgency by the industry.</td>
</tr>
</tbody>
</table>
| 13      | 1. whether you agree with recommendations on the new cases proposed for exemption as set out in Table 1; Yes, partial outages will be reviewed during the implementation of the IPM.  
2. whether the list of exempted cases should remain within the market rules or be managed under the SOM. It should be referenced in Market Rules but details stipulated under the SOM as these are operational issues.  
3. whether the minimum penalty amount and the penalty rate should be revised; We note that partial outage will be reviewed during IPM implementation.  
We note PSO’s view.  
We are of the view that a minimum penalty amount of $5000, coupled with the current penalty rate (with current average (USEP+HEUC) below $100), do not provide sufficient incentives for MPs to minimise deviation in many circumstances. |                                                                                                                                                                                                                                                                         |
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<td></td>
<td>The decision to impose minimum penalty amount is based on the Value of Loss Load. The principle should still apply and not based on market price trend.</td>
<td>Specifically, the penalty would be the same for all deviations between 10.1MW and 110 MW. We therefore propose that the penalty floor of $5000 be lowered/removed and a tiered penalty rate be applied. This would reduce a generator’s indifference towards deviating between 10.1MW and 100MW and allow the penalty amount to be more reflective of their impact on the system.</td>
</tr>
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</table>

**Tuas Power Generation’s comments**

14 1) On de-loading or load run-back due to plant issues to prevent the GRFs from tripping, we would like to clarify if partial output reduction has been taken into consideration in the calculation of the EORR for conventional GRFs as per EMA’s determination paper on “Intermittency Pricing Mechanism”. Tuas Power’s position is that the GRF should not be double penalised with AFPS and SPF/EORR for the same deviation. We would like to clarify that partial output reduction, if not due to a forced outage/technical issue, is not taken into consideration in the calculation of the EORR for conventional GRFs. We note Tuas Power’s view that GRFs should not be doubly penalised for the same deviation.

15 2) We do not support the proposal to revise the minimum penalty amount and penalty rate for reasons due to the recent low market clearing prices. This is because such low market conditions are expected to be temporary and when market conditions normalised, the revised penalty scheme may become over punitive and lead to adverse reactions from the market players, such as tripping the GRFs instead of paying the high penalty amount. Such actions may have more significant impact to the power system security and the market. We are of the view that a minimum penalty amount of $5000, coupled with the current penalty rate (with current average (USEP+HEUC) below $100), do not provide sufficient incentives for MPs to minimise deviation in many circumstances. Specifically, the penalty would be the same for all deviations between 10.1MW and 110 MW. We therefore propose that the penalty floor of $5000 be lowered/removed and a tiered penalty rate be applied. This would reduce the indifference towards deviations between 10.1MW and 100MW and allow the penalty amount to be more reflective their impact on the system. We note Tuas Power Generation’s concern that should the revised penalty rate be too punitive, it may create undesirable reactions from MPs.

16 3) In addition, we observe that there appears to be inconsistency between section 5.5.9 of Chapter 2 of the Market Rules and section 5.2.5A and 5C of Chapter 6 of the Market Rules. Section 5.5.9 of chapter 2 and section 5.2.5A and 5C of the market rules are to give effect to EMA’s decision that:
- EGs’ generation should be primarily for self-consumption; and
- Gross bidding of Embedded Generator where EGs are required to
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<td></td>
<td>of the generation (i.e. Injection Energy Quantity of the associated settlement account – net generation) of the EGF group in the same 12-month period. In section 5.2.5A and 5.2.5C of Chapter 6, however, uses deviation of WPQ from Declared Quantity (i.e. gross generation). In both cases, however, the auxiliary load of the Embedded Generator, which also forms part of the EGF consumption, has not been taken into account.</td>
<td>bid into the market for the “export” quantity. Further clarification from EMA might be required to better understand the policy intent. We suggest this issue be addressed separately.</td>
</tr>
</tbody>
</table>

EMC Market Operations’ Comments

17  **Proposed SPF Methodology**

- We would like to clarify the reasons for using “scheduled energy”, as opposed to “metered energy” is used to determine the denominator for calculating SPF.

18  

- Currently the number of forced outage events is counted manually. The procedure might need to be reviewed if the proposal is implemented, as processing of the data would be beyond manual computations. Some of the info listed here, for example ‘failure to synchronize’ are not available to MO. If implemented, all the required info would have to be explicitly provided to MO electronically in machine/computer processable data sets, e.g. excel.

We note that additional info needs to be obtained from relevant parties in order for EMC to calculate the SPF as proposed. EMC will work out the implementation details with relevant parties if the revised SPF methodology is supported by the RCP.

5.  **Conclusions and Recommendations**

AFPS is introduced in the SWEM to incentivise compliance with dispatch schedules, with the ultimate goal of enhancing system reliability and stability. This paper revisits the objective of the scheme and the considerations at the time when this scheme was conceived. Through an analysis of each scenario, we clarified the procedures that the GRFs/PSO should follow during certain contingency events, such as gas system stress and EMC system maintenance. This would allow better coordination among Gencos, PSO, and EMC and help minimise the impact to the system operation during such events.
EMC is of the view that the proposed changes to the AFPS are consistent with the intent of the scheme and would provide the right incentives for GRFs to comply with their schedules and ensure reliable operation of their plants.

We recommend that the RCP discuss and support
a) EMC’s recommendation on the additional cases for exemption as set out in Table 1; and
b) That the penalty floor be reduced/removed and a tiered penalty rate be applied and that EMC be tasked work on proposing such a model.

6. Deliberations at the 112th RCP meeting

The concept paper was presented at the 112th RCP meeting. The Panel’s decisions on each issue are detailed in this section.

Issue 1: Broaden Exemptions to the Penalty

The RCP unanimously supported EMC’s recommendation on the proposed additional cases for exemption set out in table below.

<table>
<thead>
<tr>
<th>Proposed Exempted Case</th>
<th>EMC’s recommendation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reduction in output in response to gas system stress</td>
<td>Should be exempted (already covered under existing exemption case)</td>
</tr>
<tr>
<td>Testing as required/ approved by the PSO</td>
<td>Should be exempted (already covered under existing exemption case)</td>
</tr>
<tr>
<td>GRFs on local control responding positively to system disturbance</td>
<td>Should be exempted</td>
</tr>
<tr>
<td>Reduction in output when running on back-up fuel</td>
<td>Should not be exempted</td>
</tr>
<tr>
<td>WTE plants who are unable to accurately forecast output</td>
<td>Should not be exempted</td>
</tr>
<tr>
<td>Unable to submit offer due to EMC’s system is down</td>
<td>Should not be exempted</td>
</tr>
<tr>
<td>Environmental Issues beyond GRF’s control</td>
<td>Should not be exempted</td>
</tr>
</tbody>
</table>

Deferred Decision
The proposed case for exemption relating to a) partial forced outage, b) de-loading and fail-to-synchronise due to forced outage is deferred. The Panel considered that for consistency, a decision should be deferred until EMC has obtained clarity from the EMA on how such events would be considered in the calculation of probability of failure/Expected Output Reduction Rate under the Intermittent Pricing Mechanism.

Issue 2: Minimum Penalty Value

The Panel requested EMC to seek clarification from the EMA on the intent of the current minimum penalty value before EMC starts to develop any new penalty model.

Issue 3: Treatment of EG Must-run Quantity
The Panel by majority vote supported EMC’s recommendation that no change is required. Details of the voting on Issue 3 are as follows:

The following RCP members supported EMC’s recommendation:
- Mr. Marcus Tan (Representative of Generation Licensee)
- Mr. Teo Chin Hau (Representative of Generation Licensee)
- Mr. Tony Tan (Representative of Generation Licensee)
- Mr. Mark New (Representative of Retail Electricity Licensee)
- Ms. Ho Yin Shan (Representative of the Market Support Services Licensee)
- Dr. Toh Mun Heng (Representative of Consumers of Electricity in Singapore)
- Mr. YK Fong (Representative of Consumers of Electricity in Singapore)
- Mr. Tan Chian Khong (Person experienced in Financial Matters in Singapore)
- Ms. Carol Tan (Representative of Transmission Licensee)
- Mr. Soh Yap Choon (Representative of the PSO)
- Mr. Henry Gan (Representative of EMC)

The following RCP member abstained from voting:
- Mr. Matthew Yeo (Representative of Wholesale Electricity Trader)
## ANNEX 1: Proposed SPF Methodology

<table>
<thead>
<tr>
<th>No.</th>
<th>Current SPF</th>
<th>Suggested Revision</th>
<th>Reasons</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>The denominator is “number of half-hourly periods where GRF is generating and connected to power system” – which is normally determined by IEQ&gt;0.</td>
<td>The denominator is “number of half-hourly periods where GRF is dispatched by PSO for energy &gt; 10 MW” – which is normally determined by scheduled energy &gt; 10MW.</td>
<td>Only forced outages in periods where a GRF is dispatched by PSO for energy &gt; 10 MW will be used to calculate SPF.</td>
</tr>
<tr>
<td>2</td>
<td>The numerator is number of instances of a forced outage of an entire GRF</td>
<td>Numerator to consider both number and size of a GRF’s forced outages</td>
<td>In addition to instances where the entire GRF trips off, instances, where GRF fails to synchronise or experience partial tripping or de-loading due to a forced outage, will also be considered.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Number - a forced outage is deemed to have occurred for a GRF in a dispatch period if a GRF, having been dispatched by PSO for energy &gt; 10MW for that dispatch period:</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>(i) experiences forced outage(s), or</td>
<td></td>
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<tr>
<td></td>
<td></td>
<td>(ii) fails to generate or under generate, due to full or partial tripping or failure to synchronize for that period.</td>
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<tr>
<td></td>
<td></td>
<td>which resulted in the GRF’s output less than its scheduled energy by more than 10MW.</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Size - for a dispatch period where a forced outage is deemed to have occurred, count the number of trips as such:</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>a) If a GRF experiences full tripping(s) and its instantaneous generation falls to zero, due to trippings, at any point in the dispatch period – numerator is counted as 1</td>
<td></td>
</tr>
<tr>
<td>No.</td>
<td>Current SPF</td>
<td>Suggested Revision</td>
<td>Reasons</td>
</tr>
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<td>------------------------------------------------------------------------------------</td>
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<tr>
<td></td>
<td></td>
<td>b) If a GRF experiences partial tripping(s) or de-loading and its lowest instantaneous generation in the dispatch period falls to only X MW given scheduled energy is YMW – numerator is counted as [Y - X / Y]</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>c) If GRF is not covered by scenarios a) and b), and it fails to generate/synchronise at all during the dispatch period – numerator is counted as 1</td>
<td></td>
</tr>
</tbody>
</table>