RCP PAPER NO.	:	**EMC/RCP/XX/2010/CP26**
SUBJECT	:	**REVIEW OF SPF METHODOLOGY**
FOR	:	**CONSULTATION**
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DATE OF MEETING	:	

Executive Summary

This paper assesses whether the current methodology for determining the standing probability of failure ("SPF") of each generation registered facility ("GRF") should be revised for a more economically efficient and fairer allocation of reserve costs amongst generators in the Singapore wholesale electricity market ("SWEM").

From our literature review and study of practices in other electricity markets, we suggest considering the following ways of revising the current SPF methodology:
(1) revise the denominator to "number of half-hourly periods where the GRF is dispatched by the PSO for energy greater than 10 MW".
(2) revise the numerator to consider both the number and size of a GRF's forced outages – for periods where a GRF is dispatched for energy greater than 10 MW.

EMC would like to seek the views of any interested parties on this concept paper, and would appreciate receiving all comments by 14 June 2010.

1. Introduction

When EMC met with industry stakeholders to establish a rules change work plan for the RCP in 2009/10, one of the proposals raised was to revise the current SPF methodology so as to better reflect the reliabilities of different types of plants. In particular, the proposer felt that multi-shaft plants are technically designed to be more reliable than single-shaft plants – i.e. unlike a single-shaft plant, when the ST or GT for a multi-shaft plants trips, the energy output of the multi-shaft plant would not be reduced to zero – thus, the SPF computation for multi-shaft plants and single-shaft plants should be differentiated to better reflect their reliabilities.

At the 48th RCP meeting in March 2010, where the rules change work plan 2010/11 was discussed, the RCP prioritized this proposal to be addressed within the next 12 months.

This paper assesses whether the current methodology for determining the SPF of each GRF should be revised for a more economically efficient and fairer allocation of reserve costs among generators in the SWEM. Section 2 explains the rationale for the allocation of reserve costs, using the modified runway method, in the SWEM and Section 3 describes the current SPF methodology. Section 4 analyses the basis for revising the SPF methodology and examines the international standards in reserve cost allocation. Our suggestions to revise the current SPF methodology are set out in Section 5.

2. Allocation of Reserve Cost in the SWEM

The design of the SWEM is based on the principle of economic efficiency[1]. Among other things, this calls for "those that cause costs to face the costs they cause". This is known as the causer-pays principle. By allocating costs to parties that are best able to manage such costs, efficient cost allocation is achieved because these parties will be incentivised to minimise cost.

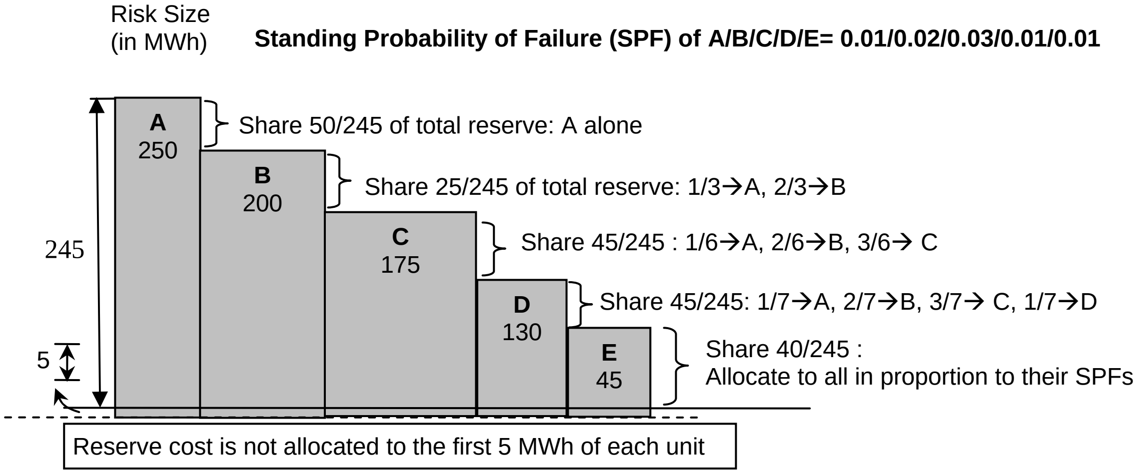
Reserve is procured to cover the risk of the loss of any single GRF. If each GRF is totally reliable in providing the energy as scheduled, then there would be no need for reserve. Hence, the need for reserve is created by the GRFs. Adopting the causer-pays principle, total reserve cost is allocated to GRFs that are scheduled to provide energy.

Total reserve cost is the sum of the products of the reserve requirement and reserve price for all three categories of reserves. Each GRF is to bear a percentage of the total reserve cost called the reserve responsibility share ("RRS"). The RRS of a GRF is calculated using a modified runway method. The rationale of the modified runway method is:

a) A GRF needs to pay for its share of the reserve procured to cover the quantum of the risk that it creates; and

b) the higher the probability of failure of a GRF, the higher the proportion of the cost it should bear.

[1] See PHB Hagler Bailly (2000), Wholesale Market Design – Memorandum to Public Utilities Board, section 1.1 on "Principles for the Wholesale Market Design".



Calculation of RRS

RRS of A =	50/245 + 25/245 x 0.01/(0.01+0.02) + 45/245 x 0.01/(0.01+0.02+0.03) + 85/245 x 0.01/(0.01+0.02+0.03+0.01) + 40/245 x 0.01/(0.01+0.02+0.03+0.01+0.01)	=**0.3387**
RRS of B =	25/245 x 0.02/(0.01+0.02) + 45/245 x 0.02/(0.01+0.02+0.03) + 85/245 x 0.02/(0.01+0.02+0.03+0.01) + 40/245 x 0.02/(0.01+0.02+0.03+0.01+0.01)	=**0.2692**
RRS of C =	45/245 x 0.03/(0.01+0.02+0.03) + 85/245 x 0.03/(0.01+0.02+0.03+0.01) +40/245 x 0.03/(0.01+0.02+0.03+0.01+0.01)	=**0.3017**
RRS of D =	85/245 x 0.01/(0.01+0.02+0.03+0.01) +40/245 x 0.01/(0.01+0.02+0.03+0.01+0.01)	=**0.0700**
RRS of E =	40/245 x 0.01/(0.01+0.02+0.03+0.01+0.01)	=**0.0204**
Sum		=**1.0000**

Figure 1 Modified Runway Reserve Cost Allocation

In Figure 1, each block represents the risk associated with one contingency event i.e. the tripping of a GRF. The height of a block represents the size of the contingency event – this is calculated as the scheduled energy quantity, in MWh[2], for every dispatch period of each GRF. The width of the block represents the likelihood of occurrence of the contingency event – this is calculated as the standing probability of failure (SPF) of each GRF. With the size and likelihood of occurrence known for each contingency event, the share of reserve cost that each contingency event should bear can then be calculated. As illustrated, reserve cost is allocated to each GRF according to the risk it creates and its SPF.

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[2] The scheduled energy for a GRF for every half-hour dispatch period is expressed in MW. To calculate RRS, the risk size of each GRF is calculated using its scheduled energy (in MW) times half an hour (1/2 hour).

3. Current SPF Methodology in the SWEM

Appendix 7A of the market rules and the paper on the current SPF methodology in the SWEM defines the probability of failure for a GRF as "the probability that the GRF will, after being dispatched by the PSO for a settlement interval, cease operating and/or disconnect from the transmission system in that settlement interval…even if no other GRF fails". The SPF methodology paper further clarifies that "disconnect", as used in the definition, refers to "either the entire or a part of the GRF is disconnected from the transmission grid".

The probability of failure for a GRF is computed by EMC based on the following equation:

$$\text{Probability of failure for a GRF} = \frac{[Number\_of\_instances\_where\_partial\_or\_entire\_GRF\_trips\_off]}{[Number\_of\_half-hourly\_periods\_where\_the\_GRF\_connected\_to\_the\_power\_system]}$$

The numerator refers to the number of instances a part of or the entire GRF trips off, from the day the GRF synchronizes into the PSO Controlled System. Should the same GRF trip off more than once within the same period on the same day, it will be treated as just one forced outage. PSO advisory notices will be used by EMC to determine the number of GRF forced outage instances. For better understanding of this rule change proposal to differentiate the SPF computation of multi-shaft plants and single-shaft plants, a table from the SPF methodology paper is reproduced here to illustrate the way trips are assigned to a typical combined cycle 2-2-1 multi-shaft plant registered as 2 logical GRFs (i.e. GRF 1 and GRF 2):

S/N	Description Convention in PSO Advisory Notice for Forced Outages concerning a 2-2-1 GRF	Type of Outages	GRF 1 considered tripped	GRF 2 considered tripped
1	G1 - GT1	GT1 Genset Trip	Yes	No
2	G2 - GT2	GT2 Genset Trip	No	Yes
3	G1 - ST	ST Genset Trip (GT2 not running)	Yes	No
4	G2 - ST	ST Genset Trip (GT1 not running)	No	Yes
5	G1 & G2 - ST	ST (Both GT1 & GT2 running)	Yes	Yes

The denominator refers to the number of periods where the GRF is generating and connected to the PSO Controlled System, generally over a one year window. This is normally based on the metered quantities of the GRF i.e. when its IEQ>0.

The standing probability of failure (i.e. SPF) for a GRF is computed quarterly, based on data gathered over a moving one year window. This computation will be done as long as there is 3 months worth of data over the relevant one year window.

4. Analysis

4.1. Basis for Revising the SPF Methodology

As explained in section 2, the principal reason for recovering the cost of reserve from generators is that doing so is economically efficient for the market. Since generators *cause* (or create) the need for reserve, recovery of reserve cost from generators is an application of the *causer-pays* principle. This is efficient because generators are made to take into account the reserve costs they impose and, thus, are incentivised to minimise such costs.

This principle has been well-established in Singapore as the Singapore Electricity Pool, which preceded the SWEM, already charged reserve costs to generators using the runway method.

PHB Hagler Bailly subsequently proposed to use the modified runway method, which modified the runway method by introducing the probability of failure of a generating unit as a factor in calculating the reserve charges to be levied on generators in the SWEM. In PHB's memo on Wholesale Market Design, it was emphasized that "the design of the reserve market is based…in particular, on the parties facing and bearing only those costs appropriately attributable to the nature of the plant they operate or the manner in which they seek to operate it"[3]. In practice, this means there is room to revise the SPF methodology if it will better reflect the reserve costs that different types of plants impose on the market – such a revision will create a sharper incentive for generators to minimize their reserve costs and, ultimately, lead to a more efficient market.

4.2. International Standards for Reserve Cost Allocation

From our literature review, we found several published articles[4] that called for the allocation of reserve cost to generators based on their cost causation (i.e. the amount of reserve costs they caused). To measure the cost causation of a generator, two "fundamental" factors should be used – its capacity and its unavailability *when scheduled*.

Of interest is a two-part formula, capturing both factors, which was proposed to allocate reserve costs to generators[5] – the first part (for unavailability) is a function of the generator's number and size of forced outages, averaged over a rolling 12-month period; the second part (for capacity) is a function of the generator's contribution to incremental reserve for the largest contingency (similar to the current SWEM's runway method) in a trading period.

It was suggested that an alternative to the first part of this formula would involve an upfront specification of the dollar amount to charge for each MW of outage. The money collected from those generators that suffered a forced outage would then be subtracted from the amount of money owed by all generators from the second part of the formula.

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[3] See PHB Hagler Bailly (2000), Wholesale Market Design – Memorandum to Public Utilities Board, section 2.14 on "Reserve Pricing and Settlement".

[4] See Strbac & Kirschen (2000), Who Should Pay for Reserve; Kirby & Hirst (2003), Allocating Costs of Ancillary Services: Contingency Reserves and Regulation; and Kirsch & Morey (2006), Efficient Allocation of Reserve Costs in RTO Markets.

[5] See Kirby & Hirst (2003), Allocating Costs of Ancillary Services: Contingency Reserves and Regulation.

We note that the New Zealand electricity market, in principle, applies this formula by allocating instantaneous reserve cost to generators and the transmission line owner in two parts – availability and event charges. For simplicity in describing the allocation of availability and event charges in the next two paragraphs, we will assume that the transmission line owner had not been allocated any reserve cost.

Availability charges[6] – akin to the second part of the formula, which captures the capacity factor – are allocated based on the proportion of a generator's online size to the aggregate online size of all generators.

Event charges[7], however, are allocated only to the causer of an event based on the net reduction in electricity arising from the event. This is akin to the first part of the formula, which captures the unavailability factor. Assuming generator A is the causer of an event – event charges levied on generator A will be calculated using the actual MW reduction multiplied by a predetermined dollar amount (i.e. like a "penalty" for each MW of forced outage). Event charges collected will then be rebated to all generators who are allocated availability charges over the period(s) in which the event occurred, based on the proportion of availability charges paid by each generator.

Our survey of markets where reserve cost, either fully or partially, is allocated to generators found that, other than New Zealand, ISO New England and PJM Interconnection also charge generators a portion of the reserve costs based on their actual deviation from schedule. In both markets, balancing charges are allocated pro rata to both generators and load in proportion to their actual real-time deviations from day-ahead schedules. The rationale for doing so is because such real-time deviations from schedule create part of the uncertainty that drives the market's need for reserve[8].

5. Suggested Revisions to the SPF Methodology

In Singapore, the modified runway method – where both the scheduled energy of a generator and its SPF are used – allocates reserve cost based on both a GRF's size and its likelihood of tripping from the power system. In section 4.1, we had established that there is room to revise the current SPF methodology if it will better reflect the reserve costs that different types of plants impose on the market. From our examination of the international standards for reserve cost allocation, we suggest considering the following ways of revising the current SPF methodology.

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[6] See New Zealand Electricity Governance Rules, Part C, Section 11.5.1 "Availability costs allocated to generators and HVDC (transmission line) owner".

[7] See New Zealand Electricity Governance Rules, Part C, Section 11.5.2 "Event costs allocated to event causers" and Section 11.5.3 "Rebates paid for under-frequency events".

[8] See Kirsh & Morey (2006), Efficient Allocation of Reserve Costs in RTO Markets.

Suggestion 1: Revise the denominator to "number of half-hourly periods where the GRF is dispatched by the PSO for energy greater than 10 MW"[9].

In the SWEM, the probability of failure for a GRF as "the probability that the GRF will, *after being dispatched by the PSO for a settlement interval*, cease operating and/or disconnect from the transmission system in that settlement interval".

The current SPF methodology calculates SPF based on a GRF's "unavailability" – currently expressed as the number of partial or entire GRF trippings – during the periods it is connected to the power system, which is normally based on its metered quantities (i.e. IEQ>0). Using IEQ>0 means that the denominator includes periods where a GRF is not dispatched for a period but is injecting energy in that period due to, for example, its ramping down – including such periods in the denominator will not be accurate for the purpose of SPF calculation. In addition, when a GRF is dispatched but is not injecting energy into the power system during that period (i.e. it is likely to have tripped in the previous dispatch period(s) or failed to synchronise for that period), this tripping will not be considered – although this tripping had created the need for reserve.

Thus, to better reflect the reserve costs imposed by a generator's trippings on the market, we suggest that the SPF for a GRF is calculated using only the number of periods where the generating unit was dispatched by the PSO for energy greater than 10 MW. The size of 10 MW is relevant because a GRF's trippings or failure to synchronise, when it is dispatched for below or equal to 10 MW, is not seen as creating the need for reserve (i.e. the runway method does not allocate reserve cost to the first 5 MWh that each GRF is scheduled for).

Suggestion 2: Revise the numerator to consider both the number and size of a GRF's forced outages – for periods where a GRF is dispatched for energy greater than 10 MW.

For the purpose of factoring the number of forced outages, we propose that a forced outage is deemed to have occurred for dispatch periods where the GRF:

(i) experiences full or partial tripping(s), or

(ii) fails to generate, due to tripping(s) in the previous dispatch period(s) or failure to synchronise for that dispatch period.

For the purpose of factoring the MW size of forced outages, for dispatch periods where a forced outage is deemed to have occurred, we propose to count the number of trips as such:

a) If a GRF experiences full or partial tripping(s) and its instantaneous generation falls to zero at any point in the dispatch period – then the numerator is counted as 1

b) If a GRF experiences full or partial tripping(s) and its lowest instantaneous generation in the dispatch period falls to only x MW, given scheduled energy is y MW – then the numerator is counted as [y-x / y]

c) If GRF is not covered by scenarios a) and b), and it fails to generate at all during the dispatch period – then the numerator is counted as 1

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[9] Section 9.1 of Chapter 5 of the Market Rules set out the issuance of dispatch instructions for each GRF by the PSO. In general, the real-time dispatch schedule released by the EMC shall be deemed as the dispatch instructions issued by the PSO – unless and until the PSO issues subsequent dispatch instructions. Where a real-time dispatch schedule is not released, the PSO shall issue dispatch instructions.

Both our literature review and study of practices in other electricity markets support the allocation of reserve cost to generators based on their cost causation (i.e. the amount of reserve costs they caused). While the measure of cost causation is different across markets, in principle, the more accurately the measure calculates the cost causation of a generator the more efficient will be the allocation of reserve cost.

With this in mind, we suggest that the SPF methodology considers both the number and the size of forced outages experienced by the GRF. The MW size of forced outages, during periods where the generating unit was dispatched by the PSO and had a forced outage, will generally be expressed as a proportion of the scheduled energy. This will better reflect the amount of reserve cost caused by the generating unit due to the unexpected drop in energy output arising from its forced outages.

Such a revision also allows the SPF to better reflect the reliability of different types of plants. A generating unit which still produces energy when it trips (e.g. GRF of a multi-shaft plant) will now have a lower SPF compared to a generating unit which has a full outage everytime it trips (e.g. GRF of certain single-shaft plants). In the long-run, such a revision can incentivise more reliable generating units to be set-up in the SWEM.

For clarity, our suggested revisions and the implications – including data needed to calculate the revised SPF – are summarized in the table below:

No.	Current SPF	Suggested Revision	Implication
1	Denominator is “number of half-hourly periods where GRF is connected to power system” – which is normally determined by IEQ>0.	Denominator is “number of half-hourly periods where GRF is dispatched by PSO for energy > 10 MW” – which is normally determined by scheduled energy > 10MW.	Only forced outages in periods where a GRF is dispatched by PSO for energy > 10 MW will be used to calculate SPF. Data: real-time dispatch schedule of GRFs released by EMC <u>or</u> PSO dispatch instructions, issued subsequent to the dispatch schedule or where a dispatch schedule is not released.
2	Numerator is “number of instances where a part of or the entire GRF trips off”	Numerator to consider both number and size of a GRF’s forced outages **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 > 10MW for that dispatch period: (i) experiences full or partial tripping(s), or	In addition to instances where part of or the entire GRF trips off, instances where GRF fails to generate will also be considered. Data: (i) instances of full or partial tripping will be determined as per current practice

		(ii) fails to generate, due to tripping(s) in previous period(s) or failure to synchronize for that period.	(ii) instances where GRF fails to generate will be determined by metered quantities i.e. IEQ is 0 or negative.
		Size - for a dispatch period where a forced outage is deemed to have occurred, count the number of trips as such: a) If a GRF experiences full or partial tripping(s) and its instantaneous generation falls to zero at any point in the dispatch period – numerator is counted as 1 b) If a GRF experiences full or partial tripping(s) and its lowest instantaneous generation in the dispatch period falls to only x MW, given scheduled energy is y MW – numerator is counted as [y-x / y] c) If GRF is not covered by scenarios a) and b), and it fails to generate at all during the dispatch period – numerator is counted as 1	The MW size of a GRF's forced outage will now be considered. Data: a) and b) For GRFs that PSO has identified as having full or partial trippings, PSO will need to indicate the GRF's lowest level of instantaneous generation in the dispatch period.

6. Consultation

EMC would like to seek the views of any interested parties on this concept paper, and would appreciate receiving all comments by 14 June 2010.