RCP PAPER NO.	:	**EMC/RCP/60/2012/CP37**
SUBJECT	:	**ALLOCATION OF REGULATION COSTS**
FOR	:	**DECISION**
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Executive Summary

This paper addresses the proposal to allocate a greater proportion of regulation costs to loads that are more "variable" as compared to "flat" loads. This is in line with the causer-pay principle, given that "variable" loads cause the need for more regulation.

The practice of charging regulation costs based on the relative variability of load and generation is currently practised in AEMO (Australian Energy Market Operator). Essentially, each generator/load is assigned a reference trajectory, and its injection/withdrawal is sampled at 4-second intervals. The deviation between actual injection/withdrawal from reference trajectory is compared against system frequency to ascertain whether the generator/load had a positive or negative impact on system stability. This in turn will determine its share of the regulation costs.

If a regulation cost allocation methodology similar to AEMO's should be applied in SWEM's context, some key considerations include:

- Whether the implementation costs involved are justified, since the proposal will likely achieve a re-ordering rather than a reduction of regulation costs, and the fact that regulation payments comprise only 0.5% of the overall market.
- Given that "stable loads" would likely opt-in to have its load performance assessed, Non-Contestable/Unmetered Customers would by default be grouped with "unstable loads", which may be unfair.
- This methodology would likely be extended to generating units for consistency, instead of simply base it on their IEQ as is current practice.

EMC would like to seek the RCP's views on:

i) Whether regulation costs should be allocated based on a unit's volatility and the impact of this volatility on system stability;

ii) If so, for EMC to:

a. Engage and visit AEMO to study their methodology in detail, and adopt their AEMO's method to SWEM's context; and

b. Estimate the costs of implementing this proposal at the overall market level.

At the 60th RCP Meeting, the Panel voted unanimously **not to support** the proposal to allocate regulation costs based on a unit's volatility and the impact of this volatility on system stability.

1. Introduction

This paper addresses the proposal received during the RCP Workplan Consultation exercise, which suggested allocating a greater proportion of regulation costs to loads that are more “variable” as compared to “flat” loads. The proposer suggested that this is in line with the causer-pay principle, given that “variable” loads cause the need for more regulation.

2. Background

Regulation is defined as the frequent adjustment to a generating unit’s output so that any power system frequency variations due to imbalances between load and the output from generation facilities can be corrected. These imbalances can be attributed to:

- Inaccuracy in system demand forecast
- Unexpected change in weather conditions
- Fluctuations in electricity consumption by the loads
- Deviation in the generators’ output from the scheduled amount

Since both loads and generators contribute to the need for regulation, regulation costs are correspondingly recovered from both groups in line with the causer-pay principle as follows:

- **Loads** – based on actual consumption as measured by their WEQ, regardless of whether the load is stable or volatile.
- **Generators** – based on actual generation as measured by their IEQ, regardless of whether the generation output is stable or volatile. The WEQ share of regulation is capped at 5MWh for any given period, with generation fluctuations above that covered by reserve.

3. Determination of Regulation Requirement

To assess if variable loads do indeed cause the need for more regulation, it is necessary to first understand how the regulation requirement is determined.

PSO determines the regulation requirement for a given period (e.g. Period 15) as follows:

a) For each Period 15 in the preceding year (total of 365 data points since there are 365 Period 15s in a year), to calculate:

   Regulation Required (RR_{15}) = Forecast Demand (VSTLF for Period 15, as published in Period 14) – Actual System Demand (sum of actual online generation of all GRFs scheduled to provide energy for Period 15)

b) Using this historical data, to construct a 99% Confidence Interval for RR_{15} using:

   99% Confidence Interval for $RR_{15} = \mu_{15} \pm 2.58^*\sigma_{15}$,

   where μ_{15} is the mean of RR_{15}

   σ_{15} is the standard deviation of RR_{15}

c) Calculate the derived period-based regulation reserve:

Derived period-based regulation = Max $(|\mu_{15}-2.58*\sigma_{15}|, |\mu_{15}+2.58*\sigma_{15}|)$

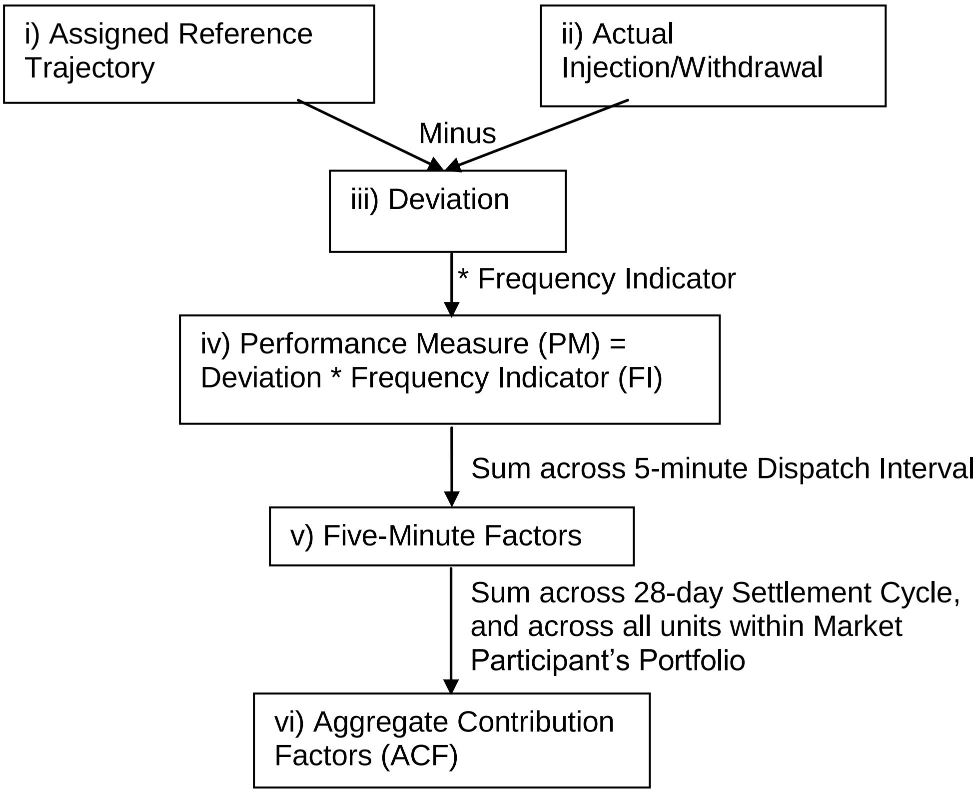
d) Cap the derived period-based regulation at 100MW, which will be used for all Period 15s in the upcoming year

A volatile load contributes to a higher RR_{15} in step a), which subsequently translates into a higher regulation requirement (assuming it is not already at the 100MW cap). The proposer's suggestion that volatile loads cause the need for greater regulation is thus fair and, in line with the causer-pay principle, should pay a greater share of regulation costs.

4. AEMO Example (Computation of Aggregate Contribution Factor)

The practice of charging regulation costs based on the relative stability of load and generation is currently practised in AEMO (Australian Energy Market Operator). The gist of its regulation cost allocation procedure[1] is as follows:

Figure 1: Computation of Aggregate Contribution Factors for Both Load and Generators



AEMO charges regulation costs to both loads and generators using the same methodology outlined in Figure 1. The key steps are described as follows:

i) Each load or generation is assigned a reference trajectory as follows:

- Scheduled generators/loads (i.e. dispatchable loads) with SCADA metering – Interpolation between dispatch targets of successive dispatch intervals

[1] The description of AEMO's regulation cost allocation is based solely on their published procedures and may not cover all operational intricacies.

- Non-Scheduled generators/loads with SCADA metering – Straight line at initial metered MW level over the dispatch interval
- Non-Scheduled loads without SCADA metering – Not assigned reference trajectory

ii) The actual injection or withdrawal quantities measured from AEMO's AGC and SCADA systems are captured through their Energy Management System. Generally the data is captured at 4-second resolution; for measurements with resolution greater than 4 seconds, the data is interpolated.

iii) The difference between the actual consumption/withdrawal and reference trajectory is taken, to capture the deviation/volatility of the generator/load

iv) AEMO further differentiates whether this deviation has a positive or negative effect on system security by multiplying it with the Frequency Indicator[2] (FI) to derive the Performance Measure as follows:

Table 1: Computation of Performance Measure

	FI is Positive **(System Frequency below 50Hz)**	**FI is Negative** **(System Frequency above 50Hz)**
Deviation is Positive (Unit is injecting more power or consuming less load)	Performance Measure is Positive (positive impact on system stability)	Performance Measure is Negative (negative impact on system stability)
Deviation is Negative (Unit is injecting less power or consuming more load)	Performance Measure is Negative (negative impact on system stability)	Performance Measure is Positive (positive impact on system stability)

v) The Performance Measures (at 4 second intervals) are then summed up across the 5-minute dispatch period to derive the 5-minute factors. All 5-minute factors affected by contingencies (e.g. unit tripping) are excluded.

vi) The 5-minute factors are then summed up across a 28-day period (AEMO's settlement cycle), and across all generators and loads[3] within each Market Participant's (MP) portfolio. This figure is the Aggregate Contribution Factor (ACF) attributed to the MP. In the aggregation process, positive factors can offset negative factors, but the final ACF for a given MP is capped at zero (i.e. the best possible ACF is 0, rather than a positive ACF). This is on the basis that only causers (negative ACFs) will be paying the regulation costs (i.e. contributors with positive ACFs will not be compensated)

The methodology described thus far calculates the ACFs for generators/loads with SCADA metering. To estimate the ACF applicable to loads without SCADA metering, AEMO will:

- **Calculate the System-wide Deviation** – Take the difference between the interpolated system forecast demand (inclusive of associated losses) as the

[2] The Frequency Indicator indicates the extent to which more generation (in which case it is positive) or less generation (negative) is required in order to keep the frequency at 50Hz.

[3] The procedures do not cover how the MPs would pass these regulation costs on to their individual customers, which are likely based on the private terms of their contracts.

reference trajectory and the actual demand (measured at generating unit terminals)

- **Derive the ACF for Non-Metered Loads** – Find the residual deviation for Non-Metered Loads by netting off the deviations attributable to individual metered generators/loads from the System-wide Deviation. The methodology in Figure 1 is then applied to this Residual Deviation to derive the ACF for Non-Metered Loads.
- **Allocate ACF to Individual Non-Metered Load** – The ACF computed for Non-Metered Loads is allocated to individual non-metered load based on the proportion of their energy withdrawals.

After computing the ACFs for all generation/load based on their "volatility" over the past 28 days, the regulation costs for a given period is allocated as follows:

Regulation Cost for Generation/Load = (Own ACF/Sum of All ACFs) * Total Regulation Costs

* Note that while Regulation Costs relate to a specific period, the ACFs are computed based on data spanning a 28-day period (i.e. each 28-day period would have its own ACF). The "Sum of All ACFs" term relate to the summation of ACFs for all units injecting/withdrawing for that given period.

5. Analysis

The Workplan proposal and AEMO's allocation of regulation costs based on volatility vis-a-vis system frequency raise two issues:

Issue 1) Should Loads bear a Lower/Higher Share of Regulation Costs based on their volatility?

SWEM subscribes to the principle of causer-pays, which implies that those who cause a greater need for a service (in this case regulation) should bear a heavier cost burden for that service. Thus, it is reasonable to charge loads that are volatile and/or deviate in a manner detrimental to system stability more. This is analogous to reserve, whereby generating units are charged a higher share of reserve costs based on the extent to which they cause the need (through the Standing Probability of Failure).

However, it is not apparent that charging loads would alter their behavior in a way to reduce the regulation requirement. If implementing this proposal only achieves a re-ordering of regulation costs (enhancing equity) rather than reducing regulation requirement (enhancing efficiency), then it is justified only if implementation costs are not too high. An additional concern is that this proposal should not be unfair to Non-Contestable/Unmetered Consumers, since they would by default be grouped with "unstable loads" since "stable loads" would already have self-selected out.

Further, implementing this proposal impinges on the following operational issues:

- **Reference Trajectory** – Since non-dispatchable loads are not subjected to schedules, they will be assigned a flat reference trajectory based on their load at the start of the dispatch period. This implies that at periods of start-up or shut-down, there are large swings in deviation and, depending on the sign of the FI, possibly a correspondingly large share of regulation costs.

- **Self-Installation of Necessary Infrastructure –** Loads that choose to opt-in for ACF assessment should install the necessary hardware/software infrastructure at their own cost, so that their load can be sampled (e.g. through SCADA) at the appropriate frequency (e.g. 4 seconds).

Issue 2) Should Gencos be similarly subjected to ACF-based regulation cost allocation?

It is reasonable to extend the ACF-based regulation cost allocation methodology to generating units for consistency, instead of simply base it on their IEQ as is current practice. Otherwise, it would not be obvious how to split regulation costs between generation and load, if one is on an IEQ-basis while the latter is on the ACF-basis.

For generating units on Automatic Governor Control, their deviations will likely contribute to system security (i.e. increase output if system frequency is low), which will lead to positive ACFs. For generating units not scheduled for regulation service, their positive performance for that period will net off their negative performance during other periods so that overall they have a beneficial ACF. However, for generating units scheduled for regulation service, their positive performance during the period should not be allowed to be included in calculations as this would effectively double-compensate them (i.e. pay them for regulation and give them "volatility credits").

Cost-Benefit Analysis

A summary of the impact of this proposal on key stakeholder groups is summarised in the table below:

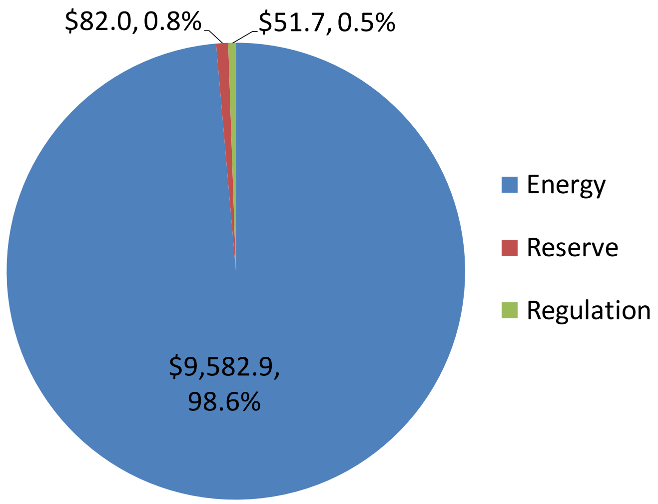
Table 2: Impact Analysis of Proposal on Key Stakeholder Groups

Groups	Cost	Benefit
Metered Generating Units	Nil	Potential reduction in regulation payments (in particular those on AGC)
Metered Load	Install hardware/software infrastructure necessary for their load to be sampled at the appropriate frequency	Potential reduction in regulation payments
Residual Unmetered Load	Potential increase in regulation payments	
PSO/MSSL/Retailers[4]	System implementation costs, and additional costs for reading and recording data for generating units and participating interval metered loads	
EMC	System implementation costs	

[4] There will be a need to install the infrastructure to read and record the SCADA data of generating units and participating interval metered loads. Further discussions are necessary to decide how the roles will be carved out between PSO, MSSL and Retailers (for billing to individual customers).

Overall Impact on Welfare	System implementation costs for Participating Metered Load, MSSL and EMC	More equitable distribution of regulation costs. Overall regulation costs unlikely to reduce though.

Figure 2: Share of Energy, Reserve and Regulation Settlement in SWEM, 2011 (in millions)



The system implementation costs described in Table 2 would have to be weighed against the relative size of the regulation market, which constitute only 0.5% of the overall wholesale market as shown in Figure 2 above. The industry would have to decide if incurring these costs are justified in order to achieve a better balancing of regulation costs in the name of equity.

6. Industry Consultation

The concept paper was published for consultation on 20 January 2012, and the following comments were received.

Comments from PSO
Significant cost for implementation changes to MSSL, EMC and PSO systems will be required to measure and settle the intra dispatch period variation of loads. Imposing very high implementation and maintenance cost not just on the MSSL, EMC and PSO systems, which would have to be paid by all consumers. In addition, consumers would be required to install and maintain expensive near real-time measuring instruments & transmit the collected data to MSSL and EMC for this to work. It would bring along a considerable disadvantage: that there is no net benefit but significant net cost to Singapore consumers as a whole.

EMC's response
PSO's comments are noted.

Comments from Senoko Energy

Senoko is not supportive of the proposed concept as it is likely to make the regulation allocations considerably more complicated (and less predictable) with limited expected changes to behaviour and hence minimal impact on aggregate regulation requirements.

EMC's response

Senoko Energy's comments are noted.

Comments from Tuas Power

- *The market is working well with the current set up regarding regulation cost allocation. Looking at the complexity and the impacts of the proposed change, it is not worth the efforts for the change.*
- *A generator on AGC that varies its output resulting in a deviation from its scheduled load (as measured by energy meters) is responding to a change command issued by the PSO which is in turn triggered by changes in load changes /system frequency. Any other deviation could be due to forced outages in which a generator is penalized through their future probability failure computation or subjected to oversight by the MSCP due to rule breaches. Extending the proposal to generating unit would tantamount to penalizing the generators for following PSO's instructions.*
- *The Singapore power system is a much smaller system than the Australian power system and its system frequency deviations are at least an order of magnitude larger and the use of the same yardstick is questionable. The energy meters at present are only capable measuring at 30 minutes resolution, how does the proposer intends the injection /withdrawal quantity and frequency deviation within the 4 secs be measured and and/or the reference trajectory be computed?*
- *In the paper page 6 table 2, it is put as 'Benefit' to Generating units that there is 'Potential reduction in regulation payments (in particular those on AGC)'. Is there any statistics to support this statement? If so please share the statistics for better understanding.*
- *In the paper page 6, when referring to the affected load, it is put as 'Participating load'. Does it mean that there is option for consumer not to participate? If not how to determine which load is 'participating'?*

EMC's response

Tuas Power's concerns on the complexity and efforts required to implement the proposal are noted.

The methodology presented penalises deviations counter to system stability, and rewards deviations contributing to system stability. Since any deviations by a generator in response to PSO's instructions are likely to be contributing the system stability, they are likely to benefit, rather than be penalized for following PSO's instructions.

This paper presents AEMO's methodology to give a sense of the complexity involved with implementing the proposal, but does not suggest importing the AEMO's model wholesale into Singapore's market. Certainly, detailed operational issues such as the sampling frequency of the interval meters and computation of the reference trajectory would need to be studied if the RCP decides to take the issue further.

As mentioned earlier, Generating units on AGC are likely to deviate in a manner that contributes to system security. Thus, under this proposed system, they are expected to be charged lower regulation costs. However, we do not have statistics to support this statement, until further studies are conducted on this issue.

With regards to “Participating Load”, the consumers do indeed have the option not to participate and consequently be grouped with the default group.

Comments from Keppel Energy

In practice, a more equitable distribution of regulation cost is arguable. The ACF approach will require installation of SCADA at load facilities. Due to high cost involved, installation is likely possible only for larger consumers. Smaller consumers will have the advantage since they are likely to be grouped together with the “positive” and “negative” netting off. Thus, in practice, the proposed rule change may unfairly allocate a larger portion of regulation cost to larger consumers.

Moreover, as mentioned in section 2, imbalance is not only caused by variable load and generation, but also

1) *Inaccuracy in system demand forecast*
2) *Unexpected change in weather conditions*

Portion of regulation cost due to the two above factors will be unfairly bore by only facilities with “negative” performance measure. We agree that cost will outweigh benefit especially when regulation market only constitutes 0.5% of wholesale market.

We do not support this rule change due to:

1) *More equitable distribution is unlikely in practice*
2) *Cost will far outweigh benefit, if any.*

EMC’s response

The larger consumers would not be worse off since they have the choice of whether to participate in this regulation cost assessment (assuming they consider themselves relatively stable) or to be grouped with the other customers.

We note Keppels’ comments that the allocation of regulation variations due to system demand or weather forecasts may not be fair, and that the implementation costs of the proposal may not be justified.

Comments from GMR Energy

GMR Energy has the following comments on the proposed allocation:

(a) The proposed allocation will result in households and non-contestable consumers bearing the brunt of regulation costs (given that it will not be economical for them to install load sampling infrastructure). We believe that this will generate unfavourable publicity for the power generation industry from a public already faced with rising electricity prices.

(b) The proposed reallocation of regulation charges would entail exceedingly complicated processes for reading load sampling data, allocation of regulation costs based on the data as well as installation of expensive infrastructure. This increases the overall costs for the supply of electricity with only seemingly minimal reallocation of costs. As regulation forms a very small proportion of the overall transaction in the electricity market, the benefits, if any, do not justify the additional cost of the infrastructure.

(c) A significant proportion of regulation exists to cover the difference in actual electricity demand and the forecast demand. Instead of spending on expensive equipment which would simply shift the cost of regulation between parties without reducing the total regulation costs, perhaps more could be done to achieve a more accurate demand forecast.

(d) For generators on AGC, the injection quantity of the generator is controlled by PSO. As such, the generating companies have no control over the fluctuation in injection quantity and should therefore not be penalized for such fluctuations. On the other hand, if generators on AGC responding to regulation will be relieved of their share of regulation costs, the general household will again end up taking up a higher share of the regulation costs.

As such, we do not support proposal contained in the consultation paper on the Allocation of Regulation Costs.

EMC's response

While the exact impact of this proposal on the relative allocation of regulation costs among various load and generator groups is unclear pending further studies, we note GMR Energy's concerns over the costs involved with the implementation.

Comments from Diamond Energy

The approach of allocating costs in NEMS is based on the causer pay principle and the consultation paper is a step in the right direction to better align the allocation of regulation costs consistent with this principle.

Whilst the current approach adopted by AEMO may provide a useful reference point, we are of the opinion that any decision to apply what AEMO has done in Singapore is premature at this time. We recommend that the EMC engage an independent consultant, ideally one with previous involvement and experience with AEMO, to develop and assess a number of regulation cost allocation alternatives for consideration.

We are supportive of the EMC's suggestion to visit AEMO to study their methodology in detail and learn from their experience first hand as an initial step. As for adopting AEMO's methodology, as suggested in the consultation paper, perhaps such a determination should be deferred until after the findings of the study trip are shared with the industry and/or a more appropriate cost allocation alternative is identified.

EMC's response

We note Diamond Energy's suggestion to engage an independent consultant and support for EMC's suggestion of a study trip. These options would be considered if the RCP decide to take the issue further.

7. Conclusion

Drawing from the Workplan proposal and AEMO's practice of charging units with volatility detrimental to system stability a greater share of regulation costs, this paper examines a possible methodology as follows:

- Each generator/load is assigned a reference trajectory
- Each generator/load's injection/withdrawal is sampled at 4-second intervals
- The deviation between actual injection/withdrawal from reference trajectory is compared against system frequency to ascertain the generator/load's

performance measure (whether it had a positive or negative impact on system stability)

- The performance measure is summed up across the dispatch period and over a 28-day period to derive the ACF[5]
- The residual deviation is allocated among non-metered loads in the proportion of their withdrawal energy to derive their ACFs
- The regulation costs applicable to a generator/load is apportioned based on the formula

Regulation Cost for Generation/Load = (Own ACF/Sum of All ACFs) * Total Regulation Costs

EMC would like to seek the RCP's views on:

iii) Whether regulation costs should be allocated based on a unit's volatility and the impact of this volatility on system stability;

iv) If so, for EMC to:

a. Engage and visit AEMO to study their methodology in detail, and adopt their AEMO's method to SWEM's context; and

b. Estimate the costs of implementing this proposal at the overall market level.

8. Decision at the 60th RCP meeting

At the 60th RCP meeting, the Panel unanimously decided **<u>not to support</u>** the proposal to allocate regulation costs based on a unit's volatility and the impact of this volatility on system stability.

[5] In the case of SWEM, there may be a need to calculate ACF on a daily basis given our daily settlement process.