RCP PAPER NO.	:	**EMC/RCP/47/2010/CP23**
SUBJECT	:	**ALLOCATION OF RESERVE COSTS TO LOAD (5% SHARE) AND GENERATION SETTLEMENT FACILITIES (GSFs)**
FOR	:	**DECISION**
PREPARED BY	:	**NERINE TEO** **ECONOMIST**
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DATE OF MEETING	:	**5 JANUARY 2010**

Executive Summary

Currently, reserve in the Singapore Wholesale Electricity Market (SWEM) is procured to cover the loss of the largest primary risk contingency unit. The total costs arising from procuring this reserve are charged to generation facilities with scheduled energy of more than 10MW ($GFs_{>10MW}$) based on the modified runway model, whereby larger shares of reserve costs are apportioned to:

a) generating facilities with higher energy schedules
b) generating facilities deemed to be relatively less reliable based on historical operations data.

This paper discusses a proposal to apportion some reserve costs to
1) Loads, specifically 5% of reserve costs
2) Generation facilities with scheduled energy of less than 10MW ($GFs_{\leq 10MW}$).

<u>Allocation of 5% of Reserve Costs to Loads</u>

SWEM operates on the principles that i) the costs of services should be charged to those who caused the need for these services, and ii) risk will be allocated to the party best able to manage it. Under both counts, it is intuitive for Generators to pay for reserve costs, since they cause the need for reserve (e.g. when they trip), and they can best manage the reserve cost risks in the system. Conversely, since load does not fulfill either of conditions, they should not be charged reserve costs.

An examination of other jurisdictions suggests that they employ different allocation

methodologies depending on the underlying principles that drive their markets. However, a literature review supports charging reserve to generators. Since SWEM is built upon the causer-pay principle, it should therefore be used as the starting point to review the reserve allocation methodology.

In conclusion, there is no justification to allocate reserve costs to load in SWEM.

Extension of Reserve Charges to $GFs_{\leq 10MW}$

Reserve is procured to cover any large unexpected generation loss in the system, while regulation is employed to address minor system fluctuations. Based on PA Consulting's memorandum, EMA's guide to the NEMS and PSO's inputs, an outage by a $GF_{\leq 10MW}$ (i.e. any generation loss less than or equal to 10MW), will not require reserve activation, as it will already be adequately covered by regulation. Applying the same causer-pay principle, $GFs_{\leq 10MW}$ should not pay for reserve charges.

EMC recommends that the RCP **retain** the existing reserve cost allocation methodology in the SWEM.

The RCP, following consideration at the 47th RCP meeting, unanimously agreed to EMC's recommendations.

1. Introduction

This paper discusses an issue prioritized in the Financial Year 2009/2010 Rule Change Work Plan, "Allocation of Reserve Costs to Loads (5% share) and Generation Settlement Facilities (GSFs)".

Currently, both Generation Registered Facilities (GRFs) and GSFs pay regulation charges up to a maximum of 5MWh each (based on IEQ), with consumers bearing the remaining regulation charges in the market. In contrast, reserve costs are charged totally to GRFs, apportioned based on their respective scheduled energy quantities above 10MW. Please refer Table 1 for a summary of the cost allocation.

Table 1: Current reserve and regulation charge allocation

	Reserve Charge	**Regulation Charge**
GRF	For scheduled energy of more than 10 MW	For first 5MWh of energy generated
GSF	No charges	For their actual generation
Load	No charges	For actual amount withdrawn from the grid

The proposer noted that based on a report undertaken by KEMA International B.V, titled "Review of Regulation Requirement in the National Electricity Market of Singapore (NEMS)", this existing arrangement translates to a regulation charge apportionment of 5:95 between generators and loads. Note, however, that this is an empirical outcome rather than a strategic apportionment based on market design.

With this allocation ratio for regulation in mind, the proposer proposed that the ratio for regulation charges be mirrored for reserve charges, such that it becomes 95:5 ratio between generators and load. This implies increasing the reserve cost allocation to loads, from the current 0% to 5%.

The stakeholder also proposed allocating reserve costs to GSFs.

There are 2 issues to address arising from this proposal:

a. Should loads pay 5% of total reserve costs?
b. Should reserve charges be extended to a generation facility[1] with scheduled energy less than or equals to 10 MW (herewith termed, $GF_{\leq 10MW}$)

Section 2 presents a summary of the existing reserve cost allocation methodology in the Singapore Wholesale Electricity Market (SWEM). Sections 3 and 4 address the 2 issues described above respectively, while Section 5 concludes.

[1] Although the proposal specifically stated GSFs, the market rules now requires that generation facilities at a generating station which has aggregate nameplate rating of more than 10 MW to be registered as one or more GRFs. As such, it is possible for a GRF to have a nameplate rating of less than 10 MW.

2. Existing Reserve Cost Allocation in the SWEM

In the SWEM, reserve is standby-by capacity to cover any energy shortages in generation, so as to enhance system security. The amount required for each dispatch period is determined based on an “N-1 reserve requirement”, whereby the amount of reserve procured should be sufficient to cover the loss of the largest primary risk contingency unit.

The total reserve costs are allocated to generation facilities with energy schedules of more than 10 MW (herewith termed, $GFs_{>10MW}$) based on the modified runway model, whereby larger generating units scheduled are apportioned a larger share of the reserve cost.

Annex 1 describes the reserve requirement and cost allocation methodology in detail.

3. Should loads be allocated 5% of reserve costs?

Addressing the proposal to allocate of 5% of reserve costs to loads requires a broader examination of whether loads should pay for reserve costs. This examination in turn calls for a re-visit of the underlying principles that drive the existing reserve cost allocation methodology, which will form the basis in analysing this proposal.

3.1 Underlying Principles of the SWEM Market Design

The current allocation method for reserve costs is grounded on the basis of economic efficiency. Based on the original market design paper[2], this principle underpins the wholesale market design as described below.

The basic principle is that of economic efficiency, which in lay and practical terms is best represented by the following:

- *Prices will be reflective of marginal costs*
- ***<u>Those that cause costs must face the costs they cause</u>***
- ***<u>Risk will be allocated to the party best able to manage it</u>***
- *These principles, and in particular unbundled marginal pricing, will be applied to the extent that the long-term gains outweigh the costs of implementing and maintaining the measure*
- *Equity, when it is addressed, must be a secondary consideration*

3.2 Analysis

The economic efficiency principle and associated statements above form the core of our analysis, which is discussed below.

<u>Those that cause costs must face the costs they cause</u>

The original intent of charging reserves to generators stems from the “causer-pay principle” described in section 3.1.

Reserve[3] in the SWEM is procured to cover the loss of generation arising from an outage, which implies that generators cause the need for reserve. After all, reserves would not be required if all generators are reliable without any probability of failure.

Therefore, based on the causer-pay principles, generators should be responsible for reserve charges.

[2] PHB Hagler Bailly, 2 August 2000 Memorandum on “Wholesale Market Design”
[3] Section D17 of Appendix 6D of Market Rules set out in detail how Reserve Requirement is determined.

Risks will be allocated to the party best able to manage it

Based on the design principle that risks should be allocated to the party best able to manage it, it is evident that generators are in a better position to manage reserve cost risks through their bids or increasing their reliability. For example, generators can manage reserve cost risk by varying the level of their generators' energy outputs relative to other generators in the system, since their relative sizes will affect their share of reserve cost. They can also increase their reliability relative to other generators, as more reliable generators in the system bear a lower share of reserve cost than less reliable generators.

Conversely, loads are unable to manage reserve cost risks, given that these risks are determined based on the generator with the largest risk in the system and is scheduled, which in turn, is reliant on the generators' schedule of bids.

3.3 Practices in Other Jurisdictions

An examination of practices in electricity markets does not indicate a consistent pattern of whether reserve is charged to loads or generators.

The underlying principles that each individual market ascribes to drive the allocation methodology employed. For example, ISO-New England allocates its reserve charges to loads, since loads benefit from the increased system security arising from reserve. This is equivalent to the beneficiary-pay principle[4] , although there was no further explanation on the rationale for adopting this principle. These charges are allocated in proportion to the varying prices across load zones.

On the other hand, New Zealand and Australia appears to be driven by the causer-pay principle.

For example, Australia recovers its contingency raise (increase energy supply in case of contingency) costs from generators, since its requirements are set to manage the loss of the largest generator. In the event that a generator experiences an outage, the system frequency will fall and reserve is required to increase this frequency to acceptable levels. On the other hand, it recovers its contingency lower (decrease energy supply in case of contingency) cost from loads, as these requirements are set to manage the loss of the largest load/transmission element on the system.[5] This is because the loss of the largest load would lead to a sudden increase in frequency and a decrease in generation is required to return the frequency to acceptable levels.

New Zealand sets its instantaneous reserve requirement to cover the largest single contingency risk, which is the greater of the MW injection from the largest generating unit or the *at risk* HVDC MW injection[6]. Part of the reserve costs arising from this requirement is then apportioned to generators, with the other portion allocated to the transmission owner of the HVDC link. A separate charge, termed event charge, is also levied on the causer of an under-frequency event. Although not explicitly stated, the link between the reserve requirement and reserve charge to generators and transmission owner suggests that the jurisdiction adopts the causer-pay principle.

[4] Presentation on "Ancillary Services Market Project Phase I and II", ISO-NE, August 2009
[5] AEMO, 24 August 2001, "Guide to Ancillary Services in the NEM"
[6] Concept Consulting Group, August 2004 "Review of Instantaneous Reserves Event Charge", Prepared for the Electricity Commission

3.4 Summary of Discussion

The rationale for allocating reserve charges to generators in the SWEM stems from the principle of economic efficiency, where costs should be allocated to those who cause the costs. Generators are also in a better position to manage reserve cost risks in the system.

The examples described in section 3.3 also suggest that jurisdictions employ different allocation methodologies, depending on the underlying principles that drive their markets. Since SWEM is built upon the causer-pay principle, it should be used as the starting point for the reserve allocation methodology undertaken in the SWEM.

A literature review[7] supports charging reserve to generators. Strbac and Kirschen (2003) concluded that in the long run, charging generators for contingency reserves incentivizes them to be reliable, driving efficiency gains. Kirby and Hirst (2003) asserted that charging reserves to customers does not cause those parties that incur the costs to pay for them and is economically inefficient, proposing that reserve be charged to generators instead.

Therefore, there is no justification to allocate reserve costs to load in SWEM.

4. Should $GFs_{\leq 10MW}$ pay for reserve charges?

Currently, reserve charges are only allocated to $GFs_{>10MW}$. $GFs_{\leq 10MW}$ are not required to pay for reserve, but are only required to pay for regulation for its actual generation, i.e. its injection energy quantity (IEQ). $GFs_{>10MW}$, on the other hand, are required to pay for regulation for first 5MWh of energy generated.

This section examines whether reserve charges should be extend to $GFs_{\leq 10MW}$.

4.1 Market Design Of Treatment of Small Generators

Similar to Section 3, the current allocation of reserve charges to $GFs_{\leq 10MW}$ stems from the fundamental market design of the SWEM. As such, it is necessary to re-visit the intent and rationale behind the existing distinction in treatment between generators with different capacities, in analysing this proposal.

Treatment of Small Generators

PA Consulting's memorandum[8] titled "Summary of the Treatment of Small and Embedded Generation in the NEM[9]" examined whether there should be any distinction across different types of generating units, with respect to licensing, registration and dispatch. It concluded that ideally, all generating units should be treated similarly. However, there will be a point at which the costs of treating small generating units in exactly the same way as large generating units exceed the benefits. As such, it determined that generating units be differentiated on the basis of capacity, defining three threshold levels with different responsibilities and obligations. These are reproduced in table 2 below[10].

[7] Strbac, G & Kirschen, D (2000) "Who Should Pay for Reserve?", The Electricity Journal, 13(8), 32-37
Kirby, B., & Hirst, E. (2003) "Allocating the Costs of Contingency Reserves" The Electricity Journal 16(10), 39-47
[8] PA Consulting Group, 21 March 2002 "Summary of Treatment of Small and Embedded Generation in the NEM"
[9] The SWEM was then referred to as the National Electricity Market (NEM).
[10] Only activities that are central to the discussion of this paper are reproduced in this table.

Table 2: Distinction of Obligations Under Different Capacities of Generating Units

Required Activity	Capacity<1MW	1MW≤Capacity≤10MW	Capacity≥10 MW
Licensed as a Generation Licence	No	Yes	Yes
Registered with EMC	No	Yes	Yes
Dispatched by EMC	No	Optional (at request of licensee)	Yes
Able to provide reserve and regulation	No	If dispatched and certified to do so by the System Operator	If certified to do so by the System Operator
Pays regulation charges	No	Yes, for their actual generation	Yes, for generation up to 10MW
Pays reserve charges	No	No	Yes, for generation ≥ 10 MW

4.2 Analysis

This section analyses whether $GFs_{\leq 10MW}$ should pay for reserve costs, taking into account the design principles described in sections 3.1 and 4.1.

Regulation versus Reserve

Regulation provision by a generating unit is defined as the frequent adjustment to its output so that any *power system* frequency variations or imbalances between *load* and the output from *generation facilities* can be corrected. Regulation costs are charged to $GFs_{>10MW}$ for the first 5MWh of energy injection[11], and to $GFs_{\leq 10MW}$for their actual generation.

Reserve is defined as generation capacity or load reduction capacity that can be called upon to replace scheduled energy supply that is unavailable as a result of a forced outage or to augment scheduled energy as a result of unexpected demand or other contingencies. As described in Annex 1, in the SWEM, it is charged to $GFs_{>10MW}$ based on their individual scheduled energy.

The design paper described in section 4.1 indicates that $GFs_{\leq 10MW}$ are only required to pay for regulation charges for their actual generation and not reserve charges. This distinction requires an examination of the intent of each of these two markets (regulation versus reserve) in the SWEM, which in turn sets the stage for the differential treatment in allocation charges between these markets.

The definition of regulation suggests that it is not intended to cover any large losses in generation, but is merely a balance mechanism to address deviations between load and generation.

On the other hand, the existence of a reserve market stems from the need to cover any shortage in generation such that system security is not compromised, i.e. avoidance of involuntary load reduction or cascading blackouts. This suggests that reserve markets in the SWEM are designed to cover large contingency losses in the system.

[11] Regulation charge is based on Injection Energy Quantities (IEQ), rather than scheduled energy.

The proposed allocation of reserve charges to GFs$_{\leq 10MW}$ invokes the question of whether a forced outage of a GF$_{\leq 10MW}$ would result in a large contingency loss in the system, which in turn, results in a need for reserve. Although the threshold amount for an impactful generation loss may vary across systems (and jurisdictions), it can be inferred from the memorandum that the capacity of GFs$_{\leq 10MW}$ (which fall into the category of between 1 MW and 10 MW) are not large enough to require activation of reserve.

This is further reinforced by the Energy Market Authority's (EMA) guide to the NEMS[12], which states that regulation is recovered from load and the first 5 MWh of each generating facility being dispatched, since it is load and small variations in generation that create the need for regulation.

This statement implies that variations of generation of up to 5MWh would be adequately met by regulation. Therefore if GFs$_{\leq 10MW}$ (i.e generators whose scheduled energy is less than 10 MW) trips, their reduction in output can already be covered by regulation (which they do pay for). Following from the causer-pays principle discussed in Section 3.1, GFs$_{\leq 10MW}$ should correspondingly not be charged reserve costs.

4.3 Summary of discussion

The reserve market is used to cover any large unexpected generation loss in the system. Based on PA Consulting's memorandum and EMA's guide to the NEMS, it can be implied that an outage by a GF$_{\leq 10MW,}$ i.e. any generation loss of less than or equal to 10MW will not require reserve activation. Applying the causer-pays principle, which forms the basis of the market, GFs$_{\leq 10MW}$ should not pay for reserve charges.

5. Conclusion

The proposal to charge 5% of load for reserve requires a broader examination of whether reserve costs should be allocated to load.

As discussed in Section 3, based on SWEM design principles, reserve cost should be charged to generators because they cause the need for reserve and they are in a better position to manage the risk of reserve cost than loads. Different jurisdictions allocate reserve costs to either generators or loads, but a literature review suggests that it is more efficient to charge reserve costs to generators. Given that SWEM subscribes to the causer-pay principle, there is no justification to allocated reserve cost to loads.

Section 4 has demonstrated that GFs$_{\leq 10MW}$ should not pay for reserve charges. This conclusion is based on the premise the first 5MWh of any generating unit constitutes small variations in generation that can be covered by regulation, and would not require any activation of reserve. Therefore, GFs$_{\leq 10MW}$ should not pay for a service (i.e. reserve) they did not cause.

6. Industry Consultation

This paper was published for industry comments on 06 November 2009, and the following comments were received from Senoko.

Senoko's Comments

In this paper there are two different classes of participants – loads (i.e. customers) and GSFs less than or equal 10 MW.

[12] EMA, July 2009 "Introduction to the National Electricity Market of Singapore"

Senoko can accept that based on the objective of reserves, it is not appropriate to apply reserve costs on loads. (It is important to note that the loss of a large load does cause system variances although the current market has no mechanism to recover costs from these lost loads.)

<u>EMC's Response</u>

We note Senoko's concurrence with EMC's view that reserve charges should not be allocated to loads.

<u>Senoko's Comments</u>

However, it appears rather tenuous to argue that GSFs≤10 should also not bear the reserves burden on the basis that regulation would already "cure" 5MWh of the problem. Regulation and reserves are two very different types of energy and cannot be substituted for each other.

By this argument, the EMC also appears to admit that a lost GSF does cause a measure of problem to system security.

It is also inaccurate to conclusively state that a trip by these GSFs would not require any activation of reserves.

Although the individual capacity of each GSF is "small", the total capacity represented by these GSFs may be sizeable. Unlike GRFs such as Senoko, these GSFs have no market incentive or disincentive to maintain the reliability of their supply into the system. Currently, we have no insight into the impact these GSFs have on the reserves market.

It would therefore be rather premature to conclude that these GSFs are too small to cause any impact on reserves and that any outage by these GSFs would be adequately addressed by regulation.

Before this rule change proceeds any further, we would like to request the EMC conduct a preliminary analysis of whether previous trips of these GSFs had caused any significant system disturbances. Also, other relevant information can be supplied, such as the list of GSFs and their capacity, their outage records, and so on. This would go far to facilitate a more in-depth and meaningful discussion among the RCP members.

<u>EMC's Response</u>

We recognize that regulation and reserve are two distinct services. Regulation addresses any power system frequency variations or imbalances between load and the output from generation facilities, while reserve is called upon to replace scheduled energy supply that is unavailable as a result of a forced outage or to augment scheduled energy as a result of unexpected demand or other contingencies.

Although a $GF_{\leq 10MW}$ (which is not scheduled and hence not included in reserve requirement computations) does affect system security when it trips, PSO has confirmed that these trips are addressed using regulation rather than reserve, given their small size.

Given this confirmation by PSO, it is not necessary for further analysis on whether any significant system disturbances have occurred arising from trips by $GFs_{\leq 10MW}$.

7. Recommendations

EMC recommends that the RCP **retain** the existing reserve cost allocation methodology in the SWEM

8. Decision by the RCP at the 47th RCP Meeting:

The RCP, following consideration, unanimously agreed to EMC's recommendations.

Annex 1: Reserve Requirement Determination and Cost Allocation in the SWEM

1. Reserve Requirement Determination Methodology

The SWEM uses an N-1 contingency principle in determining the amount of reserve required for each reserve class in each dispatch period. This implies that the quantity of reserve required must be sufficient to cover the loss of generation due to any single contingency event. By necessity, the reserve required must be sufficient to cover the loss in the largest possible single contingency, defined as the loss of the largest primary contingency unit (PCU) with the consequent loss of all secondary contingency units[13] (SCUs).

Chapter 6, Appendix 6D, Section 6D.17 of the Market Rules states the risk of each PCU as follows:

Raw Calculated Risk= Scheduled Energy of the PCU
─ Power System Response
+ Scheduled Effective Reserve of the PCU
+ (Sum of Scheduled Energy and Scheduled Effective Reserve of all SCU)

The equation above implies that for each dispatch period, the effective scheduled reserve required for each class of reserve is determined based on the scheduled energy and effective scheduled reserve of generators, and the modelled power system response[14] to a drop in frequency.

The PSO's Risk Adjustment Factor (RAF) further scales this risk of the PCU. All classes of reserve (primary, secondary, contingency) use a similar approach.

2. Reserve Cost Allocation

The reserve cost allocation using the alternative basis would be determined as follows:

For each dispatch period, each generator is allocated a fraction of the total reserve cost (RSC) given by its Reserve Responsibility Share (RRS).

The reserve cost allocated to a generator is: RRS × RSC.

<u>For SCU m</u>

$$\text{RRS} = \begin{cases} 0, \text{ if } SQ(m) \leq 0\text{MW} \\ SQ(m)/(PRQ+SRQ), \text{ otherwise} \end{cases}$$

<u>For PCU z</u>

$$\text{RRS} = \begin{cases} 0, \text{ if } SQ(z) \leq 10\text{MW} \\ PRQ/(PRQ+SRQ) \times SPF(z) \times \\ \quad \sum_{j = z \text{ to } Z} \{[SQ(j)-SQ(j+1)]/(PRQ-10)\sum_{j = 1 \text{ to } z} SPF(j)\}, \text{ otherwise} \end{cases}$$

where:

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[13] There are currently no SCUs in the SWEM.

[14] Power system response consists of estimates of the following due to a drop in frequency: (1) Intertie contribution – increase in energy supply though the intertie with Malaysia; (2) Load damping – automatic reduction in load; (3) Gas turbine output damping – reduction in gas turbine output.

SQ(·)	= generator's scheduled energy
PRQ	= SQ(·) of the PCU with the largest SQ(·)
SRQ	= sum of SQ(·) of all SCUs with positive SQ(·)
SPF(·)	= generator's standing probability of failure
SQ(Z+1)	= 10MW

$z \in \{1, 2, \ldots, Z\}$ is an index corresponding to an ordering of PCUs in descending SQ(·).
Note: The threshold for PCUs to bear reserve cost is changed from 5MWh to 10MW, which is the level of power that when supplied over a ½h dispatch period is equivalent to 5MWh of energy.

Modified Runway Model

The reserve cost that is to be shared by the PCUs, i.e., PRQ / (PRQ + SRQ), is divided between PCUs with SQ > 10MW[15] via the modified runway formula, which in turn determines the RRS of each PCU.

The rationale of the modified runway methodology is:

1. a GRF only needs to pay for the reserve that is used to cover the quantum of risk created by itself and
2. the higher the probability of its risk, the higher the cost it should bear.

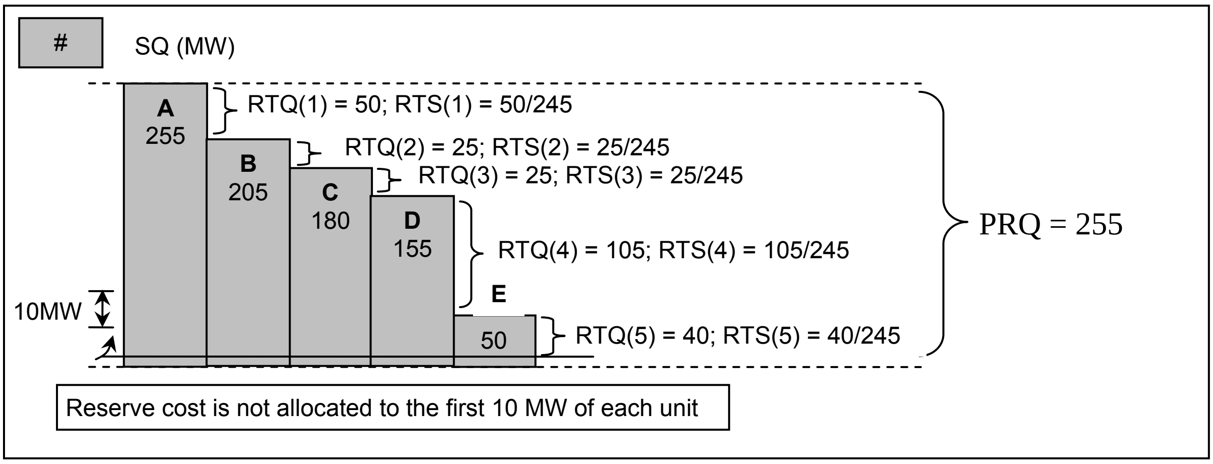
This modified runway model is described as follows:

1. PCUs are ordered in descending Scheduled Quantities (SQ) and correspondingly indexed by $z \in \{1, 2, \ldots, Z\}$.
2. Reserve tiers and corresponding reserve tier quantities are defined such that the zth reserve tier quantity [RTQ(z)] is the difference between the SQs of the zth and (z+1)th largest PCU, except the last reserve tier quantity [RTQ(Z)], which is the difference between the SQ of the smallest PCU and 10MW.
3. Reserve tiers are allocated shares of the total reserve cost to be split between PCUs, i.e., PRQ / (PRQ + SRQ[16]), in proportion to their reserve tier quantities. These shares of total reserve cost are reserve tier shares [RTS(z)].
4. The zth reserve tier share is divided among the z largest PCUs in proportion to their SPFs.
5. Shares of reserve cost in each reserve tier allocated to a PCU are summed to give its RRS.

An example of the modified runway model is given in Figure 1 overleaf.

Suppose there are no SCUs. Hence, SRQ = 0; PRQ/(PRQ+SRQ) = 1. Suppose there are 5 PCUs (A to E) with SQs and SPFs as shown below.

[15] Arising from Rule Change 244: "Allocation of Reserve Costs", reserve is now allocated to generators based on scheduled energy (MW) rather than injection energy quantity (MWh).
[16] SRQ = sum of SQs of all SCUs with positive SQ



The RRS of each PCU (A to E) is determined as follows:

PCU	A	B	C	D	E
z	1	2	3	4	5
SQ(z)	255	205	180	155	50
SPF(z)	0.01	0.02	0.03	0.01	0.02
RTQ(z) = SQ(z)–SQ(z+1)	50	25	25	105	40
RTS(z) = RTQ(z)/(250-5)	50/245	25/245	25/245	105/245	40/245
Share from RTS(1) = 50/245	0.20				
Share from RTS(2) = SPF(z) × 20/245 / (0.01+0.02)	0.03	0.07			
Share from RTS(3) = SPF(z) × 25/245 / (0.01+0.02+0.03)	0.02	0.03	0.05		
Share from RTS(4) = SPF(z) × 105/245 / (0.01+0.02+0.03+0.01)	0.06	0.12	0.18	0.06	
Share from RTS(5) = SPF(z) × 40/245 / (0.01+0.02+0.03+0.01+0.02)	0.02	0.04	0.05	0.02	0.04
RRS[17]	0.33	0.26	0.28	0.08	0.04

[17] RRSs do not sum to 1 due to rounding.

Annex 2: Practices in Other Jurisdictions

Jurisdiction	Reserve Type	Charges	Cost Recovered from
New York ISO	<u>Operating Reserve</u> 1. 10-Minute Spinning Reserve 2. 10-Minute Non-Synchronised Reserve 3. 30-Minute Spinning Reserve 4. 30-Minute Non-Spinning Reserve 5. Total 10-Minute Reserve 6. Total 30-Minute Reserve	<u>Monthly Operating Reserves Charge</u> Monthly charge = Sum of the hourly charges for the month. Where: Sum of Hourly Charges = Cost to the NYISO providing all Operating Reserves less any revenues from penalties collected during each hour X $\frac{\text{Load Serving Entity or Exports}}{\sum \text{Load in the New York Control Area and all export}}$	**1. Load Serving Entity** **2. Transmission Customer Exports**
ISO New England	1. 10-minute Spinning Reserve 2. 10-minute Non-spinning Reserve 3. 30-minute Operating Reserve	<u>Forward Reserve Charges</u> Allocated to Real-time Load Obligations in proportion to the forward reserve auction prices that vary across different load zones	**Load**
		<u>Real-Time Reserve Charges</u> Allocated to Real-time Load Obligations in proportion to the Real-Time Reserve Clearing Prices that vary across different load zones	**Load**
Pennsylvania-Jersey-Maryland (PJM) Interconnection	Synchronised Reserve	Tier 1 Reserve Charges Tier 2 Reserve Charges	**Load**
	Operating Reserves 1. Day-Ahead 2. Balancing	<u>Day-Ahead Operating Reserve Charge</u> Charged to PJM Members in proportion to their cleared day-ahead demand and decrement bids plus their cleared day-ahead exports	**Load**
		<u>Balancing Operating Reserve Charge</u> Charged to PJM Members in proportion to their real-time deviations from day-ahead schedules and generator deviations, or to PJM Members in proportion to their real-time load plus exports for generator credits provided for reliability	**Load and Generators**
New Zealand	Fast Instantaneous Reserve	<u>Availability Cost</u> This cost is allocated based on proportion	**HVDC (transmission)**

	Sustained Instantaneous Reserve	of energy injection into the system. <u>Event Charge</u> This charge is payable by the causer of an under-frequency event.	**owner and generators**
Australian Electricity Market Operator	<u>Contingency Raise</u> 1. Fast Raise Service (6s response time) 2. Slow Raise Service (60s response time) 3. Delayed Raise Service (Five-Minute Response time)	<u>Contingency Raise</u> 1. Fast Raise Service Charge 2. Slow Raise Service Charge 3. Delayed Raise Service Charge These charges are prorated over participants based on the energy generation in the trading interval.	**Generators**
	<u>Contingency Lower</u> 1. Fast Lower Service (6s response time) 2. Slow Lower Service (60s response time) 3. Delayed Lower Service (Five-Minute Response time)	<u>Contingency Lower</u> 1. Fast Lower Service Charge 2. Slow Lower Service Charge 3. Delayed Lower Service Charge These charges are prorated over participants based on consumption in the trading interval.	**Load**
CAISO	1. Spinning Reserves 2. Non-Spinning Reserves These are procured in both day-ahead market and real-time market.	Cost is allocated to demand using a system-wide user rate. The user rate is the average cost of procuring a type of AS in both the Forward and Real-Time Market for the whole CAISO system	**Load**