Energy
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| RCP PAPER NO. | : | **EMC/RCP/24/2006/CP12** |
| SUBJECT | : | **TREATMENT OF RESERVE COSTS** |
| FOR | : | **DECISION** |
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## Executive Summary


This paper assesses whether reserve cost should continue to be recovered from generators in the Singapore wholesale electricity market. We conclude that allocating reserve costs to generators is not only efficient, but fair, and not inconsistent with international best practice.

We recommend that the RCP **support** the continuance of the current arrangement for the recovery of reserve cost.

## 1. Introduction

This paper assesses whether reserve cost should continue to be recovered from generators in the Singapore wholesale electricity market.

## 2. Background

In the Singapore wholesale electricity market, the costs of reserve are currently recovered from generators.

When EMC met with industry stakeholders to establish a work plan for the Rules Change Panel in 2004/05, EMC was asked to review this treatment of reserve costs. Principally, it was argued that allocation of reserve costs to generators constrain generators to operate at sub-optimal levels (so that their reserve charges are minimised). Further, it was argued that this was inequitable since it provided load with free "insurance" as load benefited from having a highly reliable system. Lastly, it was claimed that this was inconsistent with international best practice.

This paper is structured as follows. Section 2 outlines the rationale for the current arrangement on the recovery of reserve cost and discusses the issues highlighted above. Section 3 concludes. Section 4 contains submissions received from industry stakeholders. Our recommendation is given in Section 5.

## 3. Analysis

### 3.1. Rationale for current design

The principal reason for recovering the cost of reserve from generators is that doing so is economically efficient for the market.

Reserve is standby capacity procured to cover the risk of generator failure. This is reflected in the reserve requirement being set to cover the loss of any one (by necessity, the largest) generator. 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 it gives the parties that have control over such costs the incentive to minimise the costs.

This principle has been well-established in Singapore as the Singapore Electricity Pool, which preceded the current market, already charged reserve costs to generators.

Also, it was acknowledged in RCP Paper No.: EMC/RCP/09/2003/214 (Allocating Reserve Cost to Load) that because loads do not cause generator outages nor can loads mitigate or manage the risk of generator outages, allocating reserve cost to load would compromise the overall efficiency of the market.

### 3.2. Market efficiency versus generator efficiency

Generally, the efficiency of a generator is increasing in its generation level (up to a certain generation level). Thus, it seems reasonable to argue that if reserve costs were not recovered from generators, generators would be able to run at higher, more efficient levels.

But having generators run at higher levels may not be optimal for the market as whole. This is because the higher the level a generator runs at, the greater is the risk it imposes on the system and the more reserve is required to cover its failure. Where the reserve requirement is set to manage the loss of the largest generator, a system with fewer generators running at higher levels would require more reserve than an equivalently-sized system with more generators running at lower levels. A higher reserve requirement would translate into higher cost for the market. (For example, a system with 10 generators running at 500MW would require about 500MW of reserve, whereas a system with 20 generators running at 250MW would require only about 250MW of reserve. Hence, reserve costs are likely to be higher in the first system.)

The recovery of reserve costs from generators makes generators take into account the costs that they impose. This is efficient for the market. Breaking the link between cost and causer would eliminate the incentive that generators have to minimise reserve costs. This is likely to result in higher reserve costs through higher generation levels requiring more reserve.

### 3.3. Causers versus beneficiaries

With reserve cost recovered from generators, it may seem that load is a free-loading beneficiary of the reliable system afforded by having reserve. This has been described as inequitable.

On the contrary,

- It *is* fair for generators to face the costs of reserve. Reserve is procured to cover the risk of generator failure. If generators did not fail, arguably, there would be no need for reserve. On principle, it is fair that causers of cost are allocated those costs.

- Load *does* pay for reserve – indirectly. When reserve costs are allocated to generators, these costs add to the cost of increasing generation levels and get factored into energy offers. Hence, load ultimately pays for all costs of electricity generation.

<u>Other causers</u>

The reserve requirement is determined not only by scheduled generation levels, but also by the modelled power system response, which comprises estimates of the intertie contribution, load damping, and GT output damping. Note that of these three components, only estimated GT output damping (which is based on the generation level of GT generators) increases the reserve requirement, the other two components decrease it. In view of this, it is clear that generation levels drive the reserve requirement and it is appropriate that reserve costs be recovered from generators alone.

### 3.4. International practice

A cross-jurisdictional survey of the parties that reserve cost is recovered from is given in <u>Annex 1</u>. From this, it can be readily observed that across jurisdictions the parties that reserve cost is recovered from vary. Hence, it is evident that there is no clear "international best practice" and it cannot be said that the practice in the Singapore wholesale electricity market is inconsistent with international best practice.

In New Zealand and Australia, reserve cost is recovered from generators *and* some other party. Although seemingly in contradiction with the practice in Singapore, both of these cost recovery arrangements actually similarly apply the causer-pays principle:

- In New Zealand, reserve cost is also recovered from the HVDC link owner because the reserve requirement is set to manage the loss of the largest generator or a single pole on the HVDC link, whichever is greater.

- In Australia, Contingency Raise reserve cost is recovered from generators because Contingency Raise reserve requirements are set to manage the loss of the largest generator, while Contingency Lower reserve cost is recovered from load because Contingency Lower reserve requirements are set to manage the loss of the largest load.

However, in North American markets, reserve costs are largely recovered from load. The rationale for this arrangement and the reason for it not being adopted elsewhere are unclear. But in our literature survey we found several recent, published articles[1] that called for the recovery of reserve cost from generators rather than load to reflect that generators cause these costs to be incurred and to sharpen the incentive for generators to improve the reliability of their plants. This suggests that the practice of recovering reserve cost from generators in Singapore wholesale electricity market is ahead on the evolutionary path, even if different from the practices in some other jurisdictions.

## 4. Conclusion

By allocating reserve costs – the costs the generators impose on the market – to generators, generators are made to face the costs they cause. This is an application of the causer-pays principle to the recovery of reserve costs. It is not only efficient, but fair. And it is not inconsistent with international best practice.

## 5. Consultation

In November 2005, we published a consultation notice outlining the rationale for the current reserve cost recovery arrangement and inviting industry stakeholders and other interested parties to submit their views and proposals for alternative arrangements that would enhance economic efficiency. The parties were given one month to respond.

Only one submission, which supported the maintenance of the current reserve cost recovery arrangement, was received.

**Comments from the Market Support Services Licensee, SP Services:**

> *“SP Services is of the view that the current arrangement on the allocation of reserve costs should remain. Reserve costs has traditionally been paid by gencos as they are charged to guard against their own generation loss. This was so designed to the 'causer-pays principle". Reserve costs by generators already form part of their variable cost and recovery of such costs is through their bid price. Consumers in a way already bear the reserve cost that is charged as part of the energy price. Assigning reserve costs to consumers will result in two problems:*
>
> 1. *the current system whereby reserve costs are paid by gencos cause them to take into account such costs in their power bids. As a result, gencos are incentivsed to minimise such costs, such as more regular maintenance, since they want to be scheduled. this would result in production efficiency.*
>
> 2. *if reserve costs are borne by consumers, it results in a "moral hazard" issue whereby gencos, who are in a position to control such costs, are not obliged to do so. Given time, reserve costs will therefore escalate. The loads, who cannot control such costs will end up paying more reserve costs.*
>
> *Therefore, reserve cost should continued to be borne by generators and not shared together with loads.”*

We agree with the comments from SP Services as they are in line with the reasons for the current reserve cost recovery arrangement as given in Section 3 of this paper.

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[1] See Strbac & Kirschen (2000) and Kirby & Hirst (2003).

## 6. Recommendation

We recommend that the RCP **support** the continuance of the current arrangement for the recovery of reserve cost.

## References

1. Kirby, B., & Hirst, E. (2003). Allocating the Costs of Contingency Reserves. *The Electricity Journal*, 16(10), 39-47.

2. PHB Hagler Bailly Asia (2000). Wholesale Market Design [Memorandum to Public Utilities Board].

3. National Electricity Market Management Company Limited (2001). Guide to Ancillary Services in the National Electricity Market.

4. New Zealand Electricity Governance Rules. Retrieved 12 December 2005.

5. Strbac, G., & Kirschen, D. S. (2000). Who Should Pay for Reserve? *The Electricity Journal*, 13(8), 32-37.

## Annex 1: Parties that reserve cost is recovered from

| Jurisdiction | Type of reserve | Cost recovered from |
|---|---|---|
| **ERCOT** | Responsive Reserve Service (10min); Non-spinning Reserve Service (30min) | Qualified Scheduling Entities representing Load [Load] |
| **ISO New England** | Operating Reserve (30min) | Day-ahead charges – Market Participants, in proportion to their day-ahead load obligations [Load]<br>Real-time charges – Market Participants whose real-time load deviates from the day-ahead schedule and/or whose generators deviate from day-ahead schedules and do not follow real-time dispatch instructions [Generators & Load] |
| **National Electricity Market (Australia)** | Contingency Raise (*Fast* – 6s; *Slow* – 60s; *Delayed* – 5min) | Market Generators [Generators] |
| | Contingency Lower (*Fast* – 6s; *Slow* – 60s; *Delayed* – 5min) | Market Customers [Load] |
| **New Zealand** | Instantaneous Reserve (*Fast* – 6s for spinning reserve, 1s for interruptible load; *Sustained* – 60s) | Generators, HVDC owner [Generators & Transmission line owner] |
| **NYISO** | Operating Reserve (*10-Minute Spinning Reserve*; *10-Minute Non-Synchronized Reserve*; *30-Minute Reserve*) | Load Serving Entities, Transmission Customers engaging in export [Load] |
| **Ontario** | Operating Reserve (*Ten-minute*; *Thirty-minute*) | Market Participants that withdraw energy [Load] |
| **PJM Interconnection** | Spinning Reserve (10min) | Load Serving Entities [Load] |
| | Operating Reserve (30min) | Day-ahead charges – PJM Members, in proportion to their cleared day-ahead demand and decrement bids plus their cleared day-ahead exports [Load]<br>Balancing charges – PJM Members, in proportion to their real-time deviations from day-ahead schedules [Generators & Load] |
| **Singapore** | Reserve (*Primary* – 8s; *Secondary* – 30s; *Contingency* – 10min) | Generation Registered Facilities [Generators] |

Source: ERCOT – Protocols, Section 6.9; ISO New England – Market Rule 1, Appendix F, Section III.F.3; National Electricity Market (Australia) – National Electricity Rules, Chapter 3, Section 3.15.6A(f); New Zealand – Electricity Governance Rules, Part C, Section 11.5; NYISO – Ancillary Services Manual, Section 6.4; Ontario – Market Rules, Chapter 9, Section 3.9; PJM Interconnection – Manual 28 (Operating Agreement Accounting), Sections 5 and 6; Singapore – Market Rules, Chapter 7, Section 3.3.