**Independent Market Operator**

# Reserve Capacity Mechanism Working Group (RCMWG)

## Agenda

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| **Meeting No.** | 5 |
| **Location:** | IMO Board Room,<br>Level 3, Governor Stirling Tower, 197 St Georges Terrace, Perth |
| **Date:** | Thursday 12 July 2012 |
| **Time:** | 2.00 to 5.00pm |

| Item | Subject | Responsible | Time |
|---|---|---|---|
| 1. | **WELCOME** | **Chair** | 2 min |
| 2. | **APOLOGIES / ATTENDANCE** | **IMO** | 2 min |
| 3. | **MINUTES FROM MEETING 4** | **IMO** | 10 min |
| 4. | **ACTIONS ARISING** | **IMO** | 2 min |
| | **(a) UPDATE ON ACTIONS POINTS FROM MEETING 4** | **IMO/Sapere Research Group/ ENERNOC** | 10 mins |
| 5. | **HARMONISATION OF DEMAND SIDE AND SUPPLY SIDE CAPACITY RESOURCES (WORK STREAM 2)**<br>*Presentation by Dr Richard Tooth* | **Sapere Research Group** | 60 min |
| 6. | **DYNAMIC RESERVE CAPACITY REFUND REGIME (WORK STREAM 3)**<br>*Presentation by the IMO* | **IMO** | 45 min |
| 7. | **RESERVE CAPACITY PRICE (WORK STREAM 1)**<br>*Update following workshop on 4 July 2012.* | **The Lantau Group** | 45 min |
| 8. | **GENERAL BUSINESS** | **Chair** | 5 min |

**Independent Market Operator**

**Reserve Capacity Mechanism Working Group**

## Minutes

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| **Meeting No.** | 4 |
| **Location:** | IMO Boardroom<br>Level 3, 197 St Georges Terrace, Perth |
| **Date:** | Tuesday 29 May 2012 |
| **Time:** | Commencing at 2.00pm – 5.45pm |

| **Attendees** | |
|---|---|
| Allan Dawson | Chair |
| Suzanne Frame | IMO |
| Brendan Clarke | System Management |
| Andrew Sutherland | Market Generator |
| Brad Huppatz | Market Generator (Verve Energy) |
| Ben Tan | Market Generator |
| Shane Cremin | Market Generator |
| Corey Dykstra | Market Customer |
| Patrick Peake | Market Customer |
| Steve Gould | Market Customer |
| Stephen MacLean | Market Customer (Synergy) |
| Andrew Stevens | Market Customer/Generator |
| Jeff Renaud | Demand Side Management |
| Geoff Down | Contestable Customer |
| Justin Payne | Contestable Customer |
| Wana Yang | Observer (Economic Regulation Authority) |
| **Additional Attendees** | |
| Richard Tooth | Presenter (Sapere Research Group) |
| Mike Thomas | Presenter (The Lantau Group) |
| Aditi Varma | Minutes |
| Fiona Edmonds | Observer |
| Greg Ruthven | Observer |
| **Apologies** | |
| Paul Hynch | Observer (Public Utilities Office) |

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| Wayne Trumble | Observer (Griffin Energy) |

| Item | Subject | Action |
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| 1. | **WELCOME AND APOLOGIES / ATTENDANCE**<br>The Chair opened the fourth meeting of the Reserve Capacity Mechanism (RCM) Working Group (RCMWG) at 2:05pm.<br><br>The Chair welcomed the members in attendance and noted apologies from Mr Paul Hynch and Mr Wayne Trumble received prior to the meeting. | |
| 2. | **MINUTES ARISING FROM MEETING 3**<br>The following change was noted on Page 3:<br><br>*Mr Geoff Down observed that some level of ~~uncertainty~~ flexibility needs to be factored in dispatch decisions.*<br><br>The minutes were accepted as a true and accurate record of the meeting, subject to the aforementioned change. | |
| 3. | **ACTIONS ARISING**<br>Ms Suzanne Frame noted that work would be ongoing to assess the cost-effectiveness of proposed options for harmonisation (Action Item 2). Other action items were noted as completed. | |
| 4. | **PRESENTATION: Harmonisation of Demand Side and Supply Side Resources by Dr Richard Tooth, Sapere Research Group**<br>The Chair invited Dr Richard Tooth to present his paper.<br>The following points of discussion were noted:<br>• On the issue of availability of DSM (Demand Side Management), Mr Corey Dykstra observed that Planned Outages of generators could not be equated to DSM's unavailability if dispatched because generators had already forecast the outage. Dr Tooth disagreed and noted that the effect on the market was the same in both situations i.e., facility not being available when needed.<br>• Mr Dykstra questioned if the Wholesale Electricity Market (WEM) had already matured with regard to DSM penetration. Mr Jeff Renaud noted that DSM penetration in most capacity markets in the US had plateaued at about 7-8% of total capacity. He added that the penetration in the WEM was similar although the uptake profile was steeper.<br>• On Proposal 1 *(DSP facilities may be dispatched outside of nominated availability limitations on a best efforts basis)*, Mr Cremin mentioned that dispatching DSM on a best efforts basis in an emergency operating state did not qualify as harmonisation with generators. Dr Tooth argued that generators would also be expected to perform on a best efforts basis if they were on a Planned Outage and an emergency situation was experienced, i.e. with regards to being called back to service. He noted that a baseload facility could be requested to operate in excess of its maximum sent out capacity on a best efforts basis if required.<br>• On the topic of Hours of Availability, Mr MacLean queried if the 1-in- | |

| Item | Subject | Action |
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| | 10 peak year event had been used to estimate dispatch events for DSM. He observed that the extent of generation availability on a day other than a 1-in-10 peak year event would be so much that it would minimise the need to dispatch DSM. Dr Tooth mentioned that the analysis included high demand days and Forced Outages and did not include generation availability.<br>• Discussion ensued on the sufficiency of 15 dispatch events to provide System Management enough certainty while making dispatch decisions. Mr Cremin questioned if there was merit in considering unlimited dispatch events. Mr Renaud observed that there are two different approaches used to specify DSM dispatch conditions- first, a prescriptive approach based on historical data and second, identifying system operating conditions that would trigger DSM dispatch. He noted that the latter approach is used in other international markets. Mr Cremin added that every year system reliability conditions to dispatch could change and so an unlimited number of dispatch events should be the preferred approach. Dr Tooth added that unlimited number of dispatch events with clear guidelines for dispatch was a more reasonable approach.<br>• Discussion ensued on how dispatch decisions are made currently when system reliability is under threat. Mr Clarke observed that System Management would use liquid plants before dispatching DSM. If there is a concern on fuel availability, then the order of dispatch would be different. The Chair noted that in high risk conditions, System Management would consider conservation of liquid inventory and DSP's may be dispatched before liquid plants. Mr Patrick Peake queried if System Management would hold generation or DSM as Spinning Reserve when system reliability was under risk to which Mr Clarke responded that generation would generally be held as Spinning Reserve.<br>• On the Hours of Duration for DSM, Mr MacLean requested that information be provided on why other markets have more hours of duration. Mr Renaud observed that there might be learning's from other markets that could be used to WEM's benefit. He noted that hours of duration was a complex issue for a demand side aggregator because of the need to limit the duration of load curtailment for its customers, except in cases where a back-up generator was installed. He added that this issue was closely linked to the refund mechanism. He stated an example of non-performance penalty mechanism used in New York-ISO market. Mr Andrew Sutherland asked if this risk couldn't be spread across the aggregator's portfolio. Mr Renaud noted that analysis would need to be done on how an aggregator could reconstruct its portfolio to mitigate the risk.<br>• Discussion ensued on System Management's decisions on dispatching DSM. Mr Ben Tan questioned if the risk of being dispatched at any time shouldn't lie with the DSP. Mr Renaud noted that the risk could be transferred to DSP and more flexibility provided to System Management as long as system conditions were set objectively. Discussion ensued on the system conditions needed to dispatch DSM. The Chair observed that in a high risk operating state, System Management could dispatch any capacity source in order to avoid involuntary load-shedding. Mr Mike Thomas added that in a fuel | |

| Item | Subject | Action |
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| | constrained situation, the issue is not capacity but energy.<br>• Discussion ensued on how DSM's would cope with unlimited number of hours. Mr Renaud reiterated that unlimited number of dispatch events was not a problem however the system conditions needed for DSM dispatch would need to be stated clearly.<br>• Mr Huppatz questioned if a similar analysis had been done for over the winter months as the Ready Reserve Standard are reduced in winter as Planned Outages occur predominantly during this time. He observed that System Management might not have the confidence to dispatch DSM if a fuel shortage happened in winter. The Chair noted that it would be worthwhile to conduct some analysis around the profiles of DSM during the winter months.<br>• On Notice Period for DSM's, Mr Renaud noted that a day ahead notification with two hours notice period would be welcome as it would help DSP's to prepare to respond to a dispatch event. He added that the current four hours notice period regime was also acceptable and that if it was changed, a two hours notice period with day ahead notification would reduce dispatch risk.<br>• On the Third Day Rule, Mr Renaud noted that System Management has the ability to dispatch different DSM facilities to meet the Third Day Rule. Discussion ensued on dispatching DSM in the non balancing merit order.<br>• On the topic of participation of DSP in the Balancing Market, discussion ensued on the cost of dispatching DSP compared to the cost of dispatching thermal generators. Members discussed the concept of a dynamic baseline methodology. The Chair noted that DSM's participation in the balancing market should be kept as a separate stream of work and included in the Market Rules Evolution Plan.<br>• Mr MacLean noted that differential capacity price for DSM and generators should be considered as an alternative option. Mr Renaud noted that such an approach has not worked in other markets. He gave examples of international markets where DSM participation was non-existent because a level playing ground with generators was not created. Members requested that some further information be provided so that this alternative could be assessed.<br>*Action Points:*<br>• *The IMO to conduct analysis of the profiles of DSPs during winter months.*<br>• *The IMO to present a clear set of recommendations for harmonisation of DSM with Market Generators.*<br>• *The IMO to provide to the Working Group for its consideration an overview of the experiences of international markets with differential capacity pricing* | <br><br><br><br><br><br><br>**IMO**<br><br>**IMO**<br><br>**IMO** |
| 5 | **PRESENTATION: RCM Review Report-2 by Mr Mike Thomas, The Lantau Group**<br>The Chair invited Mr Thomas to present his paper. | |

| Item | Subject | Action |
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| | The following points of discussion were noted:<br><br>• Mr Patrick Peake noted that if all capacity was uncontracted then the cost was pushed back on the providers of capacity rather than retailers.<br>• Mr Dykstra noted his concern that the steeper slope for adjusting the Reserve Capacity Price did not indicate that a retailer would be pushed towards bilateral contracting. He offered a retailer's perspective on contracting for capacity and energy to meet the Individual Reserve Capacity Requirement and noted that the Maximum Reserve Capacity Price (MRCP) was not relevant to a retailer's contracting behaviour. Mr Thomas noted that the fundamental issue was the value of capacity to the market when there is excess capacity available.<br>• Mr Cremin noted that manipulating the slope to create a market-based pricing mechanism would not create an entry barrier for new capacity. He offered that a ceiling and a floor price would be better suited to incite contracting behaviour among retailers, so that retailers contract for the amount of capacity they need and all the excess capacity is priced at the floor price. Mr MacLean noted that Mr Cremin's proposal did offer a non-zero solution. Mr Cremin added that it was important to minimize volatility by setting a floor price. Mr Stevens observed that Mr Cremin's proposal suggests incentivizing retailers to contract bilaterally thereby signalling the amount of capacity that enters the market. Mr Cremin further observed that the current mechanism is such that retailers are choosing not to contract bilaterally as the higher the uncontracted capacity, the greater the excess capacity adjustment is and the cheaper it is for retailers to procure capacity from the IMO cheaply.<br>• Mr Dykstra noted that the market design was envisaged as a bilateral contracting market and modifications had been made since market start in response to various levels of capacity. In his opinion, The Lantau Group's proposal offered another modification to deal with the current situation. It did not offer sufficient proof that a disincentive for new capacity would be created. He added that the group should consider revisiting the original set of issues and outcomes before concurring that the proposed solution was the way forward.<br>• Discussion ensued on the proposed solution being an interim solution to deal with the excess capacity currently present in the market.<br>• Mr Dykstra noted that Synergy being the largest retailer was the only one with the incentive to contract for energy. Other retailers being too small would take a conservative view and rely on the IMO's mechanisms to procure capacity. Mr Huppatz and Mr Cremin agreed with that point. The Chair noted that going forward and at the appropriate time the IMO would like to create appropriate signals for entry of capacity into the market when it was needed. Mr Tan noted that the proposed solution does not provide any correcting investment signal to capacity that enters the market with no intention of contracting. Discussion ensued on the use of price mechanism versus a spigot control mechanism. Mr MacLean observed that the proposed approach would deal transitionally with excess capacity currently present in the market.<br>• The Chair noted that the proposal had been canvassed with the IMO | |

| Item | Subject | Action |
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| | Board and the sentiment was that a slope of 3.25 might not provide a strong enough price signal. He noted that the IMO Board would favour a sharper signal.<br>• Members discussed the implications of the proposed approach. Mr Peake noted that a sharper signal would not be very welcome to investors in generation. Mr Dykstra reiterated that the proposal did not offer any incentive to contract bilaterally and that it was important to review expectations of outcomes. Mr MacLean noted that the group needed more time to evaluate possible options before coming to a conclusion.<br>• Members requested that a workshopping session be held where potential proposals would be evaluated.<br><br>*Action Points:*<br>• *The IMO to organise a workshop for RCMWG Members to evaluate alternative proposals to deal with the oversupply of capacity.* | **IMO** |
| **6** | **CLOSED**<br><br>The Chair postponed the agenda item on Dynamic Refunds to the next meeting due to lack of time and thanked all members for attending the meeting. The Chair declared the meeting closed at 5.45 pm. | |

**Independent Market Operator**

**Reserve Capacity Mechanism Working Group (RCMWG)**

## Agenda item 4: RCMWG Action Points

**Legend:**

| | |
|---|---|
| **Shaded** | Shaded action points are actions that have been completed since the last RCMWG meeting. |
| **Unshaded** | Unshaded action points are still being progressed. |

| # | Action | Responsibility | Meeting arising | Status/Progress |
|---|---|---|---|---|
| 2 | The IMO to include information on the cost effectiveness of proposed solutions or harmonisation | IMO | April | In progress |
| 4 | The IMO to conduct analysis of the profiles of DSP's during winter months. | IMO | May | Completed. Refer to Agenda Item 4(a) |
| 5 | The IMO to present a clear set of recommendations for harmonisation of DSM with Market Generators | IMO | May | Completed. Refer to Agenda Item 5 |
| 6 | The IMO to provide to the Working Group for its consideration an overview of the experiences of international markets with differential capacity pricing | IMO | May | Completed. Refer to Agenda Item 4(a) and the Appendix 1 |
| 7 | The IMO to organise a workshop for RCMWG members to evaluate alternative proposals to deal with the oversupply of capacity. | IMO | May | Completed. Workshop held July 4 2012 |

# Agenda Item 4(a): Update on Action Points from Meeting 4

# 1. Action on specific DSP proposals

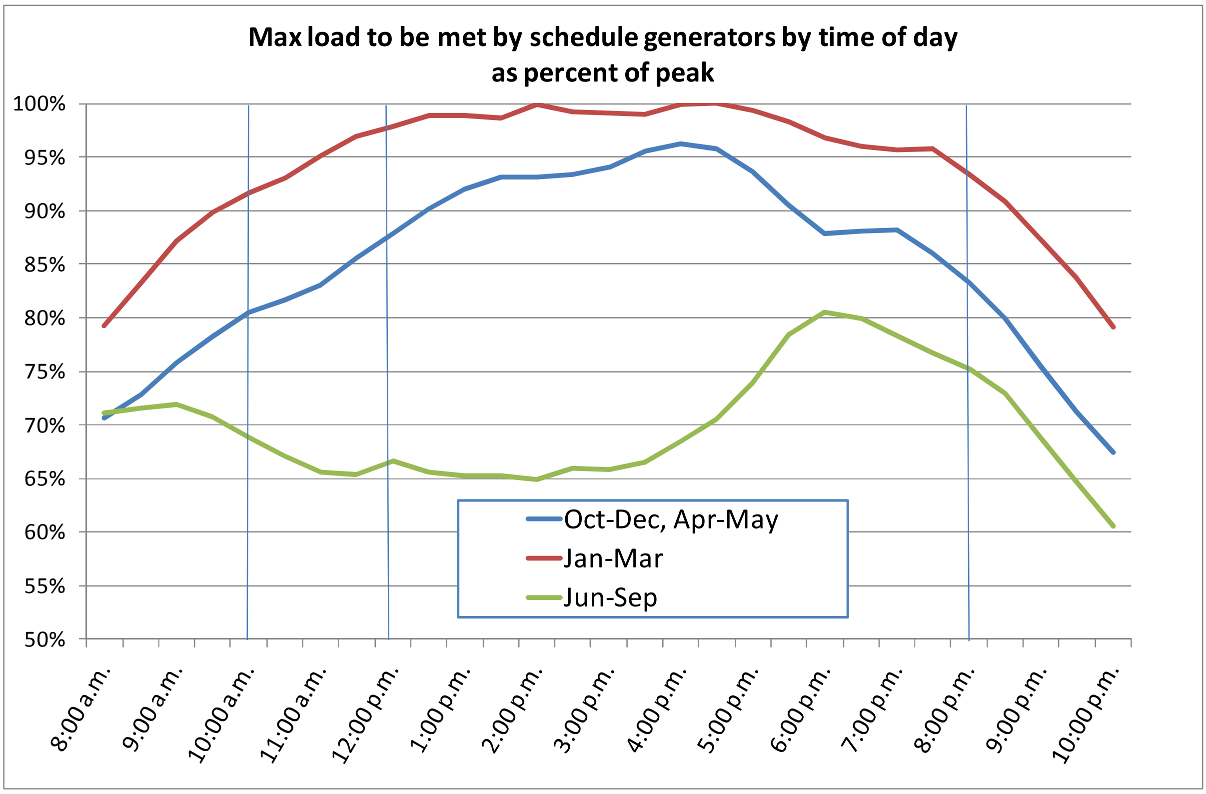
## 1.1 DSP- time of day requirements

In developing the recommended revised requirement for earliest start and latest finish, the demand profile over the course of a day was examined. The maximum demand[1] that occurred from each half hour of the day was examined relative to the peak demand. Shifting the minimum start-time from 12 noon to 10 am was recommended on the basis that the maximum demand on Scheduled Generation during these times was relatively significant compared to the absolute peak and comparable to the minimum required finish-time of 8pm

At the May 2012 RCMWG the question was raised whether winter demand profiles should also be examined to assess the time of day requirements given the large amount of outage that occurs during winter periods.

The peak profiles for seasonal periods are shown in Figure 1 and Figure 2 below. Figure 1 shows the profile relative to overall peak demand; Figure 2 shows the period profile relative to peak demand in the period. As shown in Figure 1 the demand in the shoulder and winter months is substantially lower than that of peak summer period (January to March). Figure 1 highlights that if the timing of outages was random only the Jan-Feb demand profile would be of interest.

**Figure 1: Max demand profiles for different seasonal periods relative to yearly peak**



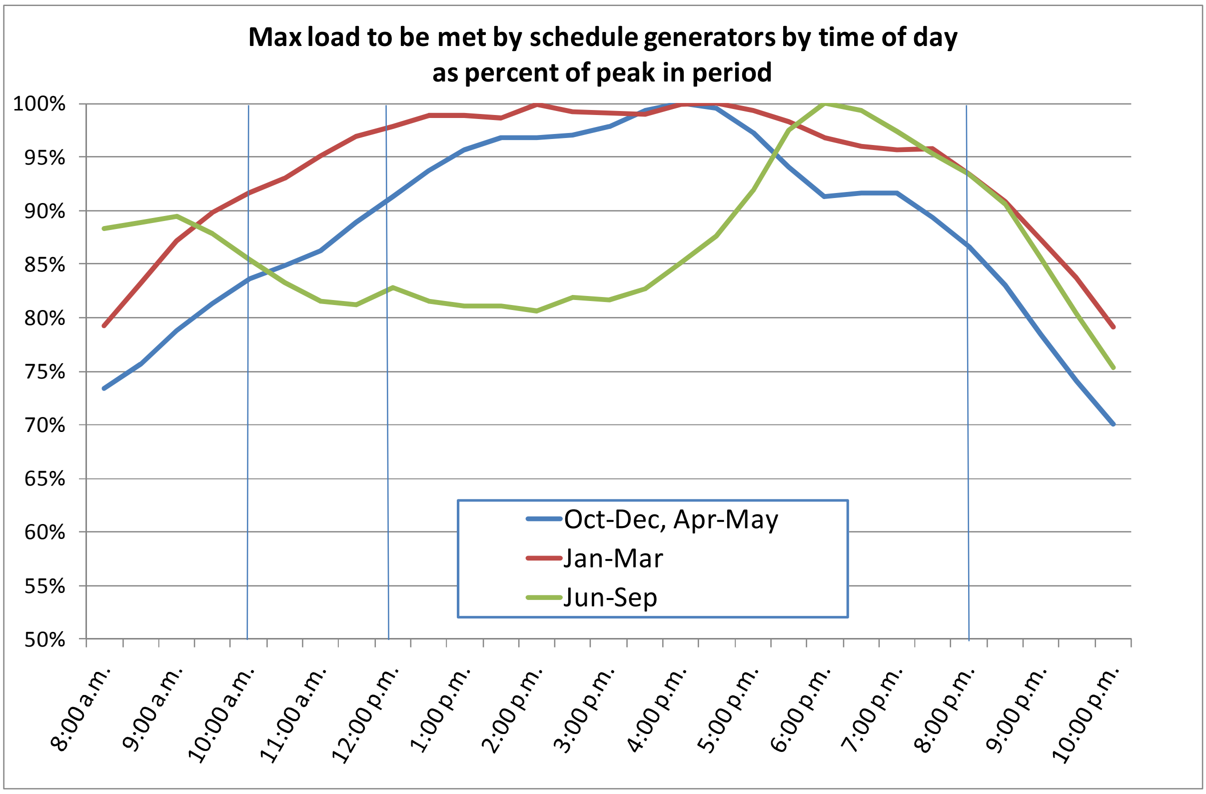

**Notes:** Based on demand plus curtailed load less intermittent generation for all years 2007/08 through to 2010/11. The profiles are similar when limited to demand over an individual year.

[1] Based on demand plus curtailed load less intermittent generation. This approach in effect reflects the load that is required to be met by scheduled resources.

However, there may be greater plant outage during non-peak and shoulder periods. As shown in figure above, the shape of the profile changes in different months; during winter demand falls during the middle of the day and then peaks around 6 pm. There is a risk that due to large plant outage during shoulder or winter periods an even wider time range is required.

This risk is examined below. In Figure 2 the profiles are normalised such that the peak in each profile is always 100% thus simulating the effect of a large plant outage. The figure indicates that the Jan-Mar period has the flattest and widest profile (in percentage terms); the maximum demand at 10am and 8pm is as close (or closer) to the peak in the Jan-Mar profile as any other period. There is year by year variation but the data suggests that the 10am to 8pm requirement would be sufficient for shoulder and non-peak periods as well.

**Figure 2: Normalised maximum demand profiles**



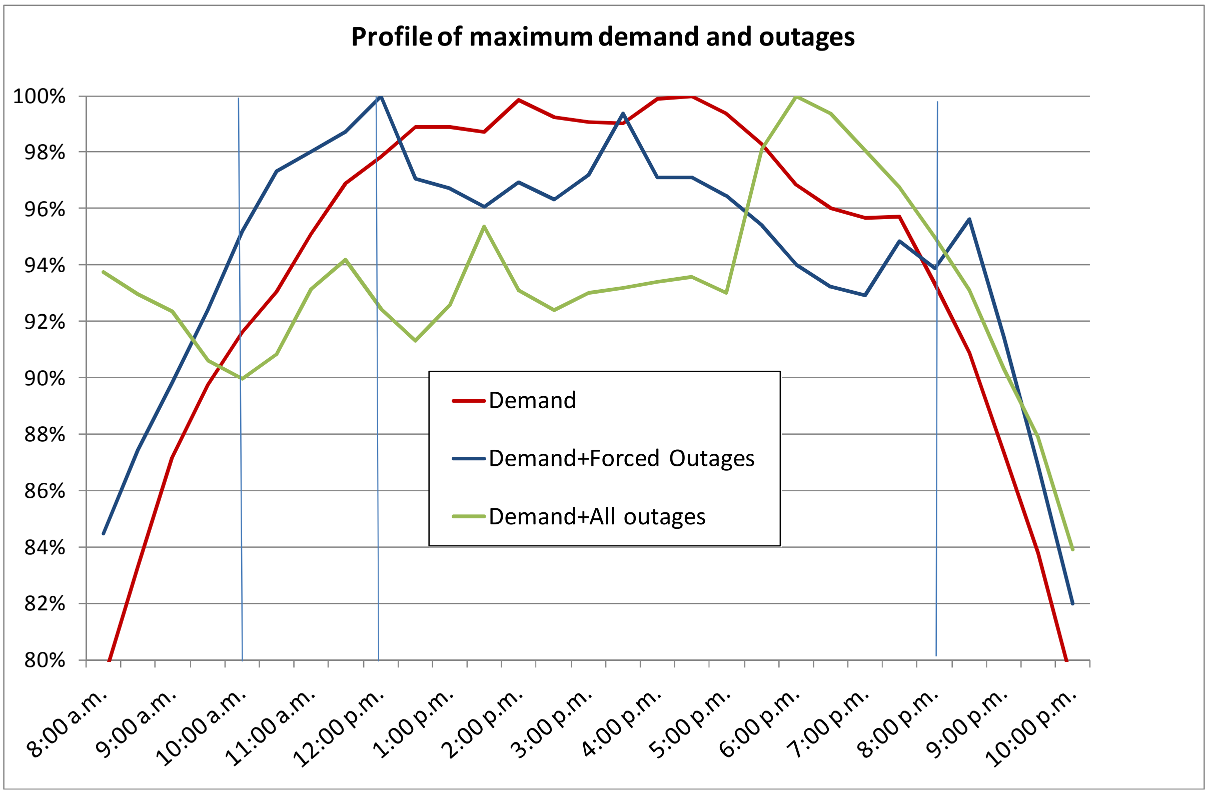

**Notes:** Based on demand plus curtailed load less intermittent generation for all years 2007/08 through to 2010/11. The profiles are similar when limited to demand over an individual year.

Figure 3 below shows the effect of including outages. The effect of outages is added to demand; in effect, treating outages like additional demand.[2] When outages are included, the 'adjusted load' profile changes slightly. The addition of forced outages pushes the peak to early earlier in the day (when forced outages are more likely to be reported). The addition of all outages (i.e. fixed, consequential and planned outages) causes the winter 'adjusted load' profile to be dominant with a peak later in the day.

The patterns presented in Figure 3 might be used to argue for an even wider time period. However, the significance of outages is questionable. Planned outages need to be approved and thus should not be expected at a time when reliability is at risk. While there is some evidence to suggest forced outages are more frequent in the morning, this seems likely to reflect when problems are detected; if an extreme peak day was expected it would seem reasonable that problems would be detected, and thus resolved, earlier.

2 The sum of demand plus outages is inversely related to the amount of available surplus capacity.

**Figure 3: Maximum demand including outages**




**Notes:** Based on demand plus curtailed load less intermittent generation for all years 2007/08 through to 2010/11. The profiles are similar when limited to demand over an individual year.

## 1.2 DSP - Hours per day

The May report recommended that the minimum hours per day be shifted from 4 to either 6 or 8 hours per day. An outstanding action was to finalise a recommendation.

On balance it proposed that 6-hour duration is used. A rationale for the 6-hour duration is that there is acceptance of two key recommendations that would facilitate more efficient DSP use, namely that:

- DSPs can be dispatched on a best-efforts basis outside the requirements
- DSPs will be required (overtime) to provide real-time information which should enable efficient dispatch

Furthermore, the higher availability requirements placed on DSPs would contribute to a lower penetration of the DSM in the market, which will, in turn, ease the need for longer durations. Finally as noted as highlighted in previous paper:

- DSP use can be staggered, which will be supported by real-time information.
- DSPs ramp up and ramp down.
- Some DSPs will nominate for longer periods.

# 2. Pricing of demand side measures elsewhere

An additional request following previous meetings was for some background information on the pricing of demand side management in other systems. A review of the North American markets was undertaken.

There are a range of different demand side management (DSM) programs. These can be broadly categorised as:

1. Capacity DSM, whereby DSM is a scheduled capacity resource which receives a capacity payment for being available and must respond to dispatch instructions
2. Energy only DSM that is voluntarily dispatched
3. DSM for ancillary services such as balancing services

Payments for types 1 and 2 are considered below. In general:

- "Capacity DSM" will generally receive a capacity payment and in most cases a dispatch payment
- "Energy DSM" will receive a dispatch payment but no capacity payment

### Capacity payments

Where there are dual (capacity and energy) markets (e.g. PJM, NYISO, ISO-NE) capacity DSM receives a capacity payment that is comparable to a capacity payment for a generation resource. Where capacity markets do not apply, the network operator may directly procure DSM capacity resources, generally via competitive tender.

In the main, DSM is paid for capacity just like another capacity resource. However there are slight modifications. Examples are:

- *Separate prices for low availability DSM.* The PJM Capacity Demand Response program has three separate products each with different levels of availability. There are limitations put on the lower availability products and an auction mechanism determines the clearing price for each product. Thus lower availability products receive a capacity payment that reflects the clearing capacity price for the level of availability
- *Separate DSM procurement.* ERCOT runs Emergency Interruptible Load Service (EILS) program. It procures capacity in 4 month blocks through a tender process. Caps are put on the amount that can be procured and the cost of the program. The tender process determines the capacity price.
- *Adjustments to capacity resources.* Another approach is to modify the capacity awarded to all resources based on performance. In the PJM, the value of capacity resources is based on Unforced Capacity (UCAP) value which reflects an adjustment for the force outage rate of the resource. The offered capacity of both scheduled generators and DSM programs is modified (see Box 1 below).

### Dispatch payments

DSM resources generally receive dispatch payments that reflect the market price of dispatch. These payments may be referred to as subsidies as they are additional payments made to DSM resources that are paid by other market participants. Generally these payments are made at the dispatch price of other generators. Again there are a number of slight variations in how these are applied.

- A minimum dispatch payment is often used. For example, under NYISO's Emergency Demand Response Program (EDRP), dispatch is voluntary and participating resources receive no capacity payment; dispatched resources receive the higher of $500 per MWH and the clearing energy price.

- For voluntary Energy Only DSM a trigger price may be applied below which the DSM resource does not receive a dispatch payment. For example, in PJM this was set at $75 per MWH. The trigger price helps to mitigate the cost and the distortion caused by the subsidies when load reduction is voluntary.

**Box 1: Capacity adjustment for capacity resources in PJM**

**Value of PJM resources**

Value of generation resource is based on its Unforced Capacity (UCAP) value which is calculated as:

UCAP = ICAP x (1-EFORd)

Where

- Installed Capacity (ICAP)value of a unit is based on the summer net dependable rating
- Equivalent Demand Forced Outage Rate (EFORd)is a measure of the probability a generating unit will not be available due to forced outages or deratings when it is needed to operate.

The equivalent value of a Demand Resource (DR) is:

Nominated DR Value x DR Factor x FPR

Where:

- Nominated DR value is the unadjusted capacity value
- DR Factor (0.956 for 2014/15) reflects an adjustment for differences is when DR is measured and likely to be applied. This reflects, for example, that a given value of demand reduction (measured on a normal day) is not enough when the load is higher on a hotter day.
- FPR (Forecast Pool Requirement) is equal to the (1+ IRM)*(1 – pool average EFORd) = 1.0809 (for 2014/15), where
  - IRM =15.3% for 2014/15 is the Installed Reserve Margin - based on a modelling study that reflects a number of risks.
  - For 2014/15 the pool wide average EFORd is 0.0625

Thus relative to the nominated value there is an upward adjustment to DR (a factor of 1.03) and a downward adjustment to generation resources (on average, 1 - 0.625)

## Treatment of demand response in other markets

July 2012

### Summary


- In all known capacity markets, Demand Response (DR) is treated as a capacity resource, and it receives the same payment as generation.
- Some capacity markets also feature "economic" DR programmes, in which DR can participate in the energy market in a similar manner to generation. These programmes are for voluntary dispatch under non-emergency situations, and do not provide a guaranteed level of capacity.
- Economic DR programmes are much smaller than capacity-based programmes, and tend to be treated as "add-ons" to the main capacity-based programmes: the same resources typically enrol for both.
- Vertically-integrated utilities tend to pay for DR on a capacity basis.
- Energy-only markets which lack a capacity mechanism tend to fail to elicit efficient levels of DR. Some energy-only markets have introduced capacity-based programmes for DR to overcome this.
- There do not seem to be any markets – whether energy-only or capacity-based – that discriminate between DR and generation resources, paying DR a lower price than generation.
- PJM has multiple DR capacity products. The product that is available all year is paid the same as generation. The prices paid for summer-only products can come out lower if more capacity is offered at auction than is needed, but often do not.


### Capacity markets

Table 1 shows the penetration of DR in the major capacity markets in the US, relative to the forecast 1-in-10 year peak demand for the most recent available summer.

*Table 1: DR penetration in major US capacity markets.*

| Market | Capacity-based DR | Energy-based DR |
|---|---:|---:|
| PJM | 7.6% | 0.9% |
| ISO-NE | 6.6% | 0.6% |
| MISO | 8.1% | 0.4% |
| NYISO | 6.5% | 0.8% |

In each case, the capacity-based emergency programme dominates, with the energy-based/economic programme being relatively small.

In PJM, the capacity-based programme is called the Emergency Load Response Program, and the energy-based one is called Economic Load Response. Almost all resources in the Economic Load Response programme also participate in the Emergency Load Response Program.

In ISO-NE, the capacity-based programme is the Forward Capacity Market, and the energy-based one is called Day-Ahead Load Response. Again, almost all resources which participate in the Day-Ahead programme also participate in the Forward Capacity Market.

In MISO, Load Modifying Resources participate on a capacity basis, and the Emergency Demand Response programme provides only energy payments.

In NYISO, Special Case Resources are paid for capacity, and the Emergency Demand Response Program and Day-Ahead Demand Response Program pay only for energy.

In both MISO and NYISO, dual participation is not allowed, so the resources which participate in the energy-only programmes tend to be those which are unwilling to commit to mandatory dispatches.

## Vertically-integrated utilities

EnerNOC provides around 1,500 MW of DR capacity to the following utilities, all on a capacity basis: Allegheny Power, Baltimore Gas & Electric, Burlington Electric Dept, Bonneville Power Administration, Delmarva Power, Duquesne Light Company, Idaho Power, Midwest Energy, Pacific Gas & Electric, PacifiCorp, Pepco, PPL Electric Utilities Corporation, Public Service Company of New Mexico, Puget Sound Energy, Salt River Project, San Diego Gas & Electric, Southern California Edison, Tampa Electric Company, Tennessee Valley Authority, TransGrid, Tucson Electric Power, and Xcel Energy (Colorado).

## Energy-only markets

### *OPA*

The Ontario Power Authority has an energy-only market. It runs an energy-only DR programme, called DR1. Historically, this have not been very reliable – on average, around 33% of enrolled capacity has actually responded to dispatch instructions.

In 2008, OPA introduced a capacity-based DR programme, called DR3. This was designed to provide a reliable resource, and to appeal to large industrial energy users.

OPA does not publish capacity or reliability figures, but our understanding is that DR3 is now at 2.2% penetration, and has near 100% performance. DR1 is below 0.1% penetration.

### *ERCOT*

ERCOT, in Texas, is also an energy-only market. However, it runs two capacity-based programmes for DR: Load Resources and the Emergency Response Service (ERS). Together these account for 2.2% DR penetration. The performance requirements for ERS are being relaxed so as to encourage greater participation, to help alleviate resource adequacy concerns.

### *NEM*

The NEM has not yet introduced a capacity-based mechanism for DR, and hence has a minimal level of DR. The NEM's Scheduled Load construct is often cited as a mechanism for energy-only DR participation. However, in practice it is not used for this: the only Scheduled Loads are two sets of pumps belonging to pump-storage hydroelectric schemes.

## Multiple DR products in PJM

Beginning in 2014/15, PJM will several different DR availability classes:

- Annual DR – available all year round
- Extended Summer DR – available May-Oct
- Limited DR – available Jun-Sep, for a limited number of dispatches

As in the WEM, based on the forecast load-duration curve, certain minimum amounts of capacity must be procured in the higher availability classes. Unlike in the WEM, the ownership of generation is sufficiently diverse in PJM that auctions can be used to set capacity prices.

In the auctions, Annual DR and generation resources are treated identically, as the highest availability class. Bids may be accepted from this class out of price order if necessary to ensure that enough capacity in the high availability class clears the auction. Similarly, bids from Extended Summer DR may be accepted before a lower-priced Limited DR bid, if necessary to fill the quotas.

If these out-of-order bids occur, then the prices for the three availability classes can separate. However, as Table 2 shows, they do not tend to separate by much.

*Table 2: Capacity prices paid in PJM, as proportions of the full capacity price.*

| Region | Availability class | 2014/15 | 2015/16 |
|---|---|---|---|
| **RTO (default)** | Annual/generation | 100.0% | 100.0% |
| | Extended Summer | 100.0% | 100.0% |
| | Limited | 99.6% | 87.2% |
| **MAAC** | Annual/generation | 100.0% | 100.0% |
| | Extended Summer | 100.0% | 100.0% |
| | Limited | 91.9% | 89.6% |
| **ATSI** | Annual/generation | n/a | 100.0% |
| | Extended Summer | n/a | 90.2% |
| | Limited | n/a | 85.3% |

Report for the Independent Market Operator

# Performance requirements for demand-side and supply-side capacity resources
# July – Working Group Meeting


***Dr Richard Tooth***


July 2012

# About the Author

Dr Richard Tooth is a Director with the Sydney office of Sapere Research Group. He works on public policy, competition and regulatory issues across a number of industries including water, energy, transport and financial services. Dr Tooth has a PhD in Economics, a Master in Business Administration and a Bachelor of Science.

# About Sapere Research Group Limited

Sapere Research Group is one of the largest expert consulting firms in Australasia and a leader in provision of independent economic, forensic accounting and public policy services. Sapere provides independent expert testimony, strategic advisory services, data analytics and other advice to Australasia's private sector corporate clients, major law firms, government agencies, and regulatory bodies.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# Contents

# Glossary

| | |
|---|---|
| DSM | Demand Side Management |
| DSP | Demand Side Programme |
| MWh | Megawatt hour |
| RCM | Reserve Capacity Mechanism |
| RCMWG | Reserve Capacity Mechanism Working Group |
| SWIS | South West Interconnected System |
| WEM | Wholesale Electricity Market |

# 1. Introduction

This is the third report for the Reserve Capacity Mechanism Working Group (RCMWG) on the issue of 'Performance requirements for demand-side and supply-side capacity resources'. It follows on from and complements the prior reports provided at the April and May RCMWG meetings. Further background to the project from the prior report is contained in Box 1 below.

This paper puts forward some specific proposals for changing fuel supply requirements for Scheduled Generators and finalises the proposals that were agreed at the May RCMWG meeting with regards to Demand Side Management (DSM) performance requirements.

The rest of the report is structured as follows:

- The following section (Section 2) discusses the fuel requirements for Scheduled Generators.
- Section 3 discusses final considerations of the DSM proposals discussed at the last meeting.

**Box 1: Background**

The Reserve Capacity Mechanism (RCM) is a mechanism to support the Wholesale Electricity Market (WEM) in the South West interconnected system (SWIS) in ensuring there is sufficient reserve capacity to meet reliability targets. The RCM allows for capacity to be provided by addition in supply-side resources (predominantly thermal generators) or through reductions in demand, known as Demand Side Management (DSM).

The Reserve Capacity Mechanism Working Group (RCMWG) has been established to assess the issues highlighted by The Lantau Group in its report "*Review of RCM: Issues and Recommendations*" (hereafter the Lantau Report).[1]

Two issues and related recommendations raised in the Lantau Report refer to the performance requirements for reserve capacity. The issues and related recommendations are:

- The role of DSM in the RCM

    Recommendation: The Lantau Group suggests harmonising the treatment of demand-side and supply-side by increasing the minimum availability requirement for Demand Side Programmes

- The fuel requirements imposed on generation capacity providers

    Recommendation The Lantau Group suggests refinement of the fuel supply requirement

Source: Report to April meeting or RCMWG.

1 This review is one of a number of work-streams established (or being considered) to review the issues associated with the RCM that were identified by The Lantau Group.

# 2. Fuel requirements issues

## 2.1 Fuel requirements overview

To receive Certified Reserve Capacity Scheduled Generators must demonstrate that their fuel storage, supply and transport arrangements are sufficient to allow 14 hours of continuous operation (see Box 2 below).

There is a concern that this requirement is not harmonised across sources of Scheduled Generation capacity and that it is inefficient. One concern is that it is unnecessarily onerous particularly for gas-fuelled peaking generators. As most gas is provided on a 'take or pay' basis, it may be not practical to establish a contract that would ensure fuel supply is available in all circumstances when the facility is expected to run only occasionally. A risk is that this leads to some gas projects not proceeding and/or some generators opting to register as a liquid fuel operation and installing on-site fuel storage. A further concern is that in the event of a major disruption, external factors may affect liquid fuel resupply arrangements.

In the April RCMWG meeting, three options were canvassed:

S1. No change or minimal change

S2. Adopt a lower minimum availability requirement

S3. Modify the commercial incentives to provide reliability

This report examines options S2 and S3 in more detail.

**Box 2: Performance requirements for Scheduled Generators**

The fuel requirements that are placed on Scheduled Generators stem from Market Rule 4.11.1 (a) which states:

> [...] the Certified Reserve Capacity for a Scheduled Generator for a Reserve Capacity Cycle must not exceed the IMO's reasonable expectation of the amount of capacity likely to be available, after netting off capacity required to serve Intermittent Loads, embedded loads and Parasitic Loads, for Peak Trading Intervals on Business Days [...] assuming an ambient temperature of 41$^{O}$ C;

Where, in Chapter 11 of the Market Rules, a Peak Trading Interval is defined as 'A Trading Interval occurring between 8 AM and 10 PM'.

This rule has been interpreted as that facilities must demonstrate that fuel storage, supply and transport arrangements are sufficient to allow 14 hours of continuous operation.

## 2.2 Lowering the fuel hours requirement

Under this option the 14 hours continuous fuel supply requirement would be lowered to reflect that it is unlikely that each Scheduled Generation Facility would be required for 14 hours continuous supply during a peak event.

If the requirement were lowered an alternative level would need to be determined. MMA (2010) estimated that a sufficient requirement is 12 hours. MMA (2010) also estimated that a 10 hour requirement would be sufficient if Facilities could share commitments and discussed means of achieving this.

However, there appears to be little value in adopting a lower minimum availability requirement as the benefits are likely to be limited and there are some costs.

A reduction in the required number of hours would be of small benefit to Facilities seeking capacity certification. For Facilities that use storage to meet the continuous-hours requirement the benefit would be negligible. For existing Facilities, the cost of storage is a sunk cost and thus the benefits of a reduction in fuel storage requirements would be negligible. For new Facilities the cost of 12 hours or 10 hours storage will only be marginally less than that of 14 hours storage.[2] Furthermore, storage costs are a relatively small component of investment costs.[3]

For Facilities such as gas-fuelled facilities that use fuel supply contracts to achieve the minimum requirement, a reduction in continuous supply requirement would be more significant, but still be only a small benefit unless the reduction in continuous hours requirement was more dramatic (e.g. to less than 6 hours).

The costs of change would not be insignificant. There would be additional administration costs of moving to a lower continuous-hours requirement. If a lower requirement was used then it would need to be periodically reviewed, as the sufficiency of the requirement depends on load profiles and the availability of other supply sources, both of which change over time. The performance requirements of Scheduled Generators are also used as the basis of assumptions regarding the availability of Scheduled Generators for undertaking an analysis of the risk to the unserved energy (USE) criterion. Any modifications to performance requirements would need to consider the impacts on the USE analysis required to be conducted by the IMO.

**Proposal 1**

There is no change to the expectation to the 14 continuous hours requirement

2 For example while fuel required for 10 hours is 30% less than for 14 hours, the circumference of the tank required would only be 15% less.

3 For purposes of the calculating 2012 Maximum Reserve Capacity Price (for 2014/15), the storage costs was estimated at less than 2 percent of the total capital cost. Source: MRCP Calculation Spreadsheet (Final Report version) available at http://www.imowa.com.au/mrcp.

## 2.3 Modify the commercial incentives to provide reliability

An alternative to focussing on performance requirements is to place more weight on commercial incentives to ensure adequate fuel supplies are maintained by Scheduled Generators. A focus on increasing commercial incentives has a number of benefits. Primarily such an approach provides for a more efficient assessment and management of risks. In effect, it transfers responsibility from the IMO to the Facility owner, who is the party best placed to assess and manage fuel risks. The resulting benefits would include:

- increasing in reliability of those Scheduled Generators where commercial incentives to be available are less than optimal
- providing Scheduled Generators greater flexibility in how they manage the risks to reliability, and
- harmonising the treatment of different capacity resources by more closing aligning incentives with requirements.

While the IMO would still maintain some responsibility, the transfer of responsibility would allow for a more efficient management of risk.

Generators have a number of existing commercial incentives to provide reliable supply. The combination of the market for energy, ancillary services and capacity refunds provide incentives for many generators to provide capacity most of the time.

However these commercial incentives may be insufficient in some circumstances to encourage Scheduled Generators to take the necessary measures to achieve the appropriate level of reliability. During peak Trading Intervals, the capacity refunds are very small relative to value of capacity. During the peak Trading Intervals the capacity refunds are in the order of 0.03 per cent of the reserve capacity price,[4] and are much smaller relative to the value of lost load.

The risk of the incentives being insufficient will be greater for high-cost peaking generators (where the profit contribution from participating in the energy market is low) and in unusual circumstances, where the benefits of additional risk management may be small. If it is expensive to ensure availability of fuel for periods when the likelihood of being dispatched is low, then generators may not put in place sufficient measures to guarantee availability.

The incentives to providing reliability could be modified through a number of means:

- Modifying the capacity refunds so they are more significant when plant is required (which could be made neutral in effect by making them less significant when plant is less likely to be required)[5]

4 In peak times the capacity refund is 6 x Monthly Reserve Capacity Price / trading intervals in the month.

5 There are few limits to this approach. Any change could be restructured such that the average loss to Scheduled Generators does not change. However, some care is required in modifying the scheme. There are costs in making the penalties too harsh as this can lead to an inefficient level of risk management (just as excessive fuel requirements could lead to an inefficient level of investment in redundancy). The penalties should not lead to higher cost of reliability than can be achieved by acquiring more capacity.

- Modifying the testing regime, to provide greater incentive for Facilities to be in a state of readiness.
- Modifying the capacity credit certification process so that that there is a more direct link between credits awarded and Facility reliability during peak times.
- Applying civil penalties should a Facility be negligent in failing to supply when required.

These options are not within the scope of this project. However, a review of the capacity refund structure including consideration of dynamic refunds is the focus of a separate work-stream.

As noted above, increasing the commercial incentives for Facilities to be available when required would have a number of benefits. An important implication of the approach is that it would help manage the IMO's obligation to only certify capacity that "exceeds the IMO's reasonable expectation of the amount of capacity likely to be available...". For example, under current arrangements the IMO requires evidence of a 'firm' fuel supply arrangement where storage is not available. If commercial incentives for reliability were sufficiently increased, the IMO could relax this requirement if it expected that the Facility owner would have sufficient incentives to take appropriate measures to ensure fuel would be available.[6] For example, under such a change the IMO might simply require that the Facility has the potential to source the fuel supplies when required from the spot market.

**Proposal 2**

The capacity refund work-stream examines modifications to capacity refunds so that the commercial incentives for Facilities are much more significant when reliability risk is greater.

Following this modification, the IMO relax its requirement to have firm fuel supply contracts in place if the capacity refund mechanism is assessed to provide sufficient commercial incentives for Facilities to be available when required.

6 The role of performance requirements for Scheduled Generators may be considered to supplement the existing commercial incentives where there is a concern that these incentives are insufficient to meet the IMO's reasonable expectation that a generator will supply capacity.

# 3. Availability of DSM

## 3.1 Overview

As noted in the May report, DSPs can nominate a number of limitations on their use subject to some minimum requirements. The existing and proposed minimum requirements are described in Table 1 below.

**Table 1: Nominated DSP availability**

| Performance requirement parameter | Current minimum requirement | Revised requirement |
|---|---|---|
| Days of availability | All business days | No change |
| Dispatch events per year | At least 6 | Unlimited |
| Hours per day | 4 hours per day | 6 hours* |
| Total hours | 24 hours | Unlimited |
| Earliest start | 12 noon | 10 am* |
| Latest finish | 8pm | 8 pm* |
| Minimum notice period of dispatch | Must be less or equal to 4 hours | 2 hours + day before notice (best endeavours) of probable dispatch |
| **Other changes** | **New requirement** | |
| Telemetry | All future DSPs must provide a telemetry service that enables real time information on availability and performance to be recorded. For existing DSPs will also provide a service but transition arrangements will apply. | |
| Third-day rule | The 'third-day rule' — whereby a DSP dispatched for a third continuous day is not subject to capacity refunds — is removed. | |
| Other | DSP Facilities may be dispatched outside of nominated availability limitations on a best efforts basis (i.e. with no implications for capacity refunds for non-performance). | |

Note: * Discussion of the requirements for "Hours per day", "Earliest start" and "Latest finish" is included in a separate paper covering action items from the previous meeting.

## 3.2 Implementation

### 3.2.1 Overview of rule changes required

There changes would require a number of amendments to Market Rules. A summary of identified areas are listed in Table 2 below. Although many amendments will be required however they should largely by straightforward. Subsequent amendments will be required to some Market Procedures to reflect the revised requirements.

**Table 2: Summary of rule changes required for DSM**

| Rules changes | Modification |
|---|---|
| Rules regarding DSM dispatch (Chapter 6 & 7) | May need to clarify when DSM will/won't be used |
| Dispatch Systems Requirements (Clause 2.35) | Need to update for the telemetry requirement |
| Dispatch process<br>(Chapter 6 & 7) | Need to update for provision of day ahead notification for DSPs |
| Availability Curve clauses<br>(Clause 4.5.12, 4.5.10e 4.5.13f, 4.11.4)<br>Appendix 3 & any reference to Availability Class | Availability Curve is now redundant. References to the Availability Curve and Availability Classes will require removal or modification |
| Information required for certification (Clause 4.10.1.f) | Update to reflect new minimum requirements |
| Certification must meet expectations (4.11.1j) | May require review |
| Third day rule (Clause 4.12.8) | Update to reflect removal of 'Third day rule' |
| Capacity refunds (Clause 4.26) | Adjustment required to reflect unlimited availability |

### 3.2.2 Interdependencies with other projects

Interdependencies with other projects and workstreams will need to be considered.

There is a significant interdependency between the DSM changes and the capacity payments refund review. Under the current capacity payment refund mechanism, the number of hours of availability is, in effect, a denominator to the capacity refund payment schedule. If this approach was applied using unlimited availability, the capacity payments refunds would become very small, thereby creating the risk that DSPs would have insufficient incentive to perform when required. This issue may be addressed as part of the capacity payments refund review. Given this interdependency it is appropriate, that the DSP changes be implemented in conjunction with the changes to the capacity payments refunds.

### 3.2.3 Transition arrangements and timing

As with any rule change it is appropriate to consider whether some transitional arrangements are required. The IMO's transition arrangements guidelines policy is that:[7]

> Transition arrangements may be justified, in economic terms, when the expected cost to a participant for applying the Rule Change to that participant materially exceeds the benefit to the WEMs objectives expected from applying the Rule Change to the participant, after allowing for the cost of any transition arrangement

The need for transition arrangements appears light. There are a number of considerations. First, the benefits to the WEM objectives primarily relate to ensuring harmonisation of performance requirements of capacity that will be procured in the future (i.e. Capacity Credits assigned as part of the 2013 Reserve Capacity Cycle and beyond). While improvements in the availability of capacity that has been (is being) procured (i.e. for Reserve Capacity up until October 2015) would improve reliability, given the surplus level of capacity the benefits of modifying existing procured capacity would appear to be minimal.

The expected costs to participants of changes to the procurement of future capacity (i.e. procured in Capacity Cycles from 2013) do not appear to be significant. The sunk cost to participating in a DSP is relatively small compared to Scheduled Generators. Furthermore, the likelihood of a tightening of the availability requirements for DSM was mooted well prior to the start of 2012 RCM Timetable. It appears unlikely that decisions made by DSPs providers and DSM load providers to date would be materially different if the results of this work-stream had been known some years ago.

From an availability perspective, the implications of most changes are reasonably light. In the medium term, they do not involve a material change in the probability of being dispatched due to the surplus capacity available. The most significant changes are likely to relate to the extension of the minimum availability to 10am and the extension of the number of hours availability.

The changes in availability requirements may have some implications for DSM aggregators who have ongoing contracts with DSM load providers. However given the changes to availability were previously mooted, it appears reasonable that the changes could be established for 2013 Reserve Capacity Cycle without transition. That is, contracts for the Capacity Credits certified during the 2013 capacity cycle should be able to fully comply with the amended availability requirements.

As noted in the prior report it is proposed that transition arrangements be considered for the provision of telemetry such that telemetry is only required for new DSPs; that is it is not an immediate requirement for existing certified capacity. In effect, existing DSPs have around 3 years until mid 2015 to ensure a telemetry service is provided.

[7] http://www.imowa.com.au/transitional_arrangements

**Proposal 3**

The DSM proposals be implemented in full for capacity procured in the 2013 Reserve Capacity Cycle for the period October 2015 to October 2016.

# Agenda Item 6: Dynamic Reserve Capacity Refund regime – Consideration to date

## 1. BACKGROUND

The Reserve Capacity Mechanism Working Group (RCMWG) Terms of Reference includes the consideration of a Dynamic Reserve Capacity Refund regime. This paper provides a background of the development of the regime to date and is intended to guide further discussions by the RCMWG with respect to the next steps in the process.

## 2. OVERVIEW OF CONSIDERATIONS TO DATE

The Dynamic Reserve Capacity Refund regime was considered by the Rules Development Implementation Working Group (RDIWG) at several meetings prior to the decision to include the regime into the review of the Reserve Capacity Mechanism. A brief overview of the key milestones in the development of the regime is presented below:

- At the 15 March 2011 meeting (Meeting 10) Mr Greg Thorpe (Oakley Greenwood) presented a paper on the Review of Capacity Cost Refunds which included for discussion the creation of a dynamically calculated refund regime and the level of refunds. At this meeting, RDIWG members agreed that a dynamic refund regime should be established.

- At the 5 April 2011 meeting (Meeting 11), the IMO presented a paper outlining the following alternative refund mechanisms:

  - A dynamic refund rate based on the reserve available in any particular interval.

  - A refund rate based on a dynamic reserve calculation overlaid with longer term factors.

  The IMO proposed the adoption of a basic reserve related refund approach. A copy of the paper containing the IMO's proposal is provided as Appendix 1 to this paper.

  During the same meeting Griffin Energy presented an alternative refund regime design that would differentiate facilities by type and therefore recognise that the incentives for availability of facilities differ.

- At the 31 May 2011 meeting (Meeting 13), the IMO provided a paper outlining the core principles behind the Reserve Capacity Refunds design. During the same meeting Mr Mike Thomas (The Lantau Group) provided the RDIWG with details of The Lantau Groups peer review of the changes proposed to the refund regime and then assess the their impact and consistency with the broader Reserve Capacity Mechanism review. A copy of The Lantau Groups paper is provided as Appendix 2 to this paper. A brief overview of the recommendations presented by The Lantau Group is provided below:

  - Consideration of the refund regime is recommended only in the context of the broader review of the RCM, as implementing the proposed dynamic refund regime without making any other changes to the RCM itself would have the effect of reducing refund exposure to generators;

- A more integrated solution would be to link changes to the refund regime to changes to the RCM itself. For example, a consistent change would see the introduction of a more market-based price paid by the IMO for Capacity Credits.

- Potential to include a symmetric aspect to the refunds regime such that penalties for failure to present capacity can be offset to a degree by the ability to present more capacity than has been accredited.

- Cautioned against early adoption of the dynamic refund regime and recommended the IMO explicitly consider the interactions between the refund regime and the Reserve Capacity Mechanism and coordinated the proposed changes.

The RDIWG accepted the of IMO/ The Lantau Group that any changes to the refund regime should be considered as part of the Reserve Capacity Review (albeit requesting that the removal of the net STEM Shortfall refund obligation proceed with the other proposed changes for the new Balancing market).

A copy of the papers presented to the RDIWG at the meetings is available on the following Market Web Site: http://www.imowa.com.au/RDIWG

## 3. RECOMMENDATIONS

The IMO recommends that the RCMWG:

- note the key milestones in the development of a dynamic refund regime to date; and
- discuss the proposed basic reserve related refund approach (Appendix 1).
- discuss the recommendations presented in The Lantau Report (Appendix 2).

Report

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# Capacity Refund Proposal: Brief Review


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Date: 26 May 2011

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# 1. INTRODUCTION

## 1.1. Scope

The Lantau Group (HK) Limited (TLG) has been asked to provide a peer review of changes proposed to the Reserve Capacity Refund (RCR) scheme.

In this review we set out the current proposals and then assess their impact and consistency with the overall Reserve Capacity regime. In conducting this review we have had regard to the Wholesale Market Objectives as set out in Section of 122(2) of the Electricity Industry Act and repeated in clause 1.2.1 of the Market Rules and the report by the IMO entitled "Review of Capacity Cost Refunds" dated 22 February 2011" (referenced in this paper as "RCCR"). TLG has also been reviewing other aspects of the Reserve Capacity Mechanism (RCM). Insights from that on-going review also inform our views of the Reserve Capacity Refund scheme.

A change to the way the RCM responds to market conditions will affect the value at stake when refunds are triggered. Alternatively, a change to the refund regime will affect the value and effectiveness of the overall RCM. We therefore have advised the IMO board that a change to the capacity refund regime should be considered in conjunction with potential changes to the RCM arising from the broader RCM review.

## 1.2. The current regime

The RCM and the capacity refund regimes currently operate as follows:

- The IMO determines the minimum Reserve Capacity requirement three years in advance;
- Asset owners or developers seek accreditation for their capacity to meet the IMO's requirement. (Other steps occur if there is a need to induce additional capacity into the market);
- Accredited capacity can enter into bilateral arrangements with loads or, failing that, can receive a flat monthly payment from the IMO at a price established by a process set out in the Market Rules;
- If the accredited capacity fails to perform as certified when it is called upon by System Management, then it must refund a portion of the capacity payment it has received or is expected to receive during the relevant Capacity Year.

The IMO describes the capacity refunds regime as a commercial contract in which capacity providers are contracted to meet certain standards of service.

## 1.3. Current situation

Currently there is excess reserve capacity in the WEM. As a result, the economic value of incremental reserve capacity is substantially below the administered capacity credit price paid by the IMO (and which has been the basis for capacity refund obligations). Furthermore, this means that the costs imposed on generators who are obligated to make refund payments can exceed, potentially greatly, the economic value at stake when an event occurs that triggers a refund obligation.

The IMO's analysis (see Figure 1) highlights the substantial disconnect between the current refund amounts and market conditions.

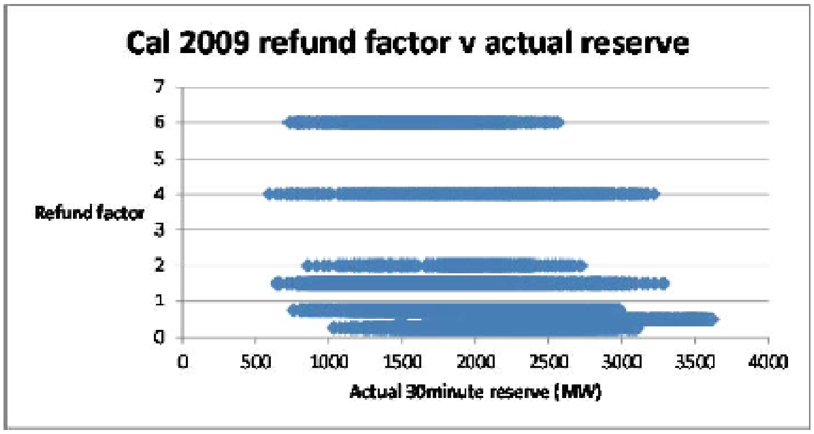


**Figure 1: IMO Analysis of the calendar 2009 refund factor vs. actual reserve**

The existing refund mechanism applies a set of "refund factors" that vary according to specific time periods, rather than to system conditions. The correlation between available reserve at a point in time and the applicable refund factor is, as a practical matter, zero. A generator can be exposed to a refund factor of 0.25 all the way up to 6.0 even if there is always 2500 MW of 30 minute reserve available. Conversely, a generator can be exposed to a refund factor ranging from 0.75 up to 6.0 when available reserve falls below 1000 MW. A generator has an incentive to ignore system conditions when scheduling maintenance, as the larger exposure is potentially to the refund factors themselves.

## 1.4. The IMO's proposal

The IMO's proposal would establish a dynamic regime that links more clearly to market conditions. Under the proposal, exposure to refunds would depend, in part, on the amount of reserve capacity available rather than on predefined time periods.

The idea of flexing the value of capacity refunds with the amount of excess capacity makes good sense. But how tight should the relationship between refunds and economic value be? During periods of excess capacity, the economic value of an incremental MW of reserve capacity can be extremely low. Conversely, during periods of looming shortage, the economic value of access to one more MW of reserve capacity can be extremely high. A regime that fully reflected short-term market conditions has the potential to be extremely volatile.

The IMO's proposal retains the use of refund factors which supress this volatility. The refund factors cap the maximum refund exposure and set a floor for the minimum obligation. Implicitly the factors imply that a trade-off between the accuracy of the economic signal and risk profile that is transmitted by that signal to stakeholders. This same question of how sharply to align the value of capacity credits with the economic value of reserve capacity is also relevant to the broader review of the RCM.

The linkage between the capacity refund regime and the value of capacity credits in the overall RCM is an important one. Given current excess reserve capacity, the proposed dynamic refund regime would reduce the value of refund payments. A reduction in capacity refund exposure without corresponding reduction in the value of capacity credits would increase the expected value to generators from the overall RCM. Perversely, such one-sided change would increase the incentive to bring more capacity into the WEM at a time when the economic value of such incremental capacity is close to zero.

Linking changes to the refund regime to changes in the broader RCM would reduce the risk of unsynchronized and unintended effects.

# 2. ASSESSING THE DYNAMIC PROPOSAL

## 2.1. OVERVIEW

The proposed changes to the RCR regime represent an improvement in the form of the existing design. But we have concerns related to the potential disconnect between changes to the RCR and the workings of the overall RCM. Sensible changes to the RCR regime that are implemented without making corresponding changes to the RCM can introduce distortions. One concern is the focus on efforts to reduce cost of the RCM through the implementation and design of the RCR regime. Another concern is that the design and implementation of the RCR at times attempts to treat blurs the distinction between capacity and energy as wholly separate products. We therefore have included a brief comment on the distinction between these two products in the context of the WEM.

Furthermore, by considering changes to the RCR *in conjunction* with those to the RCM, it might be possible to identify a more fundamentally robust mechanism.

## 2.2. IDENTIFIED ISSUES AND OBJECTIVES

The RCCR identifies a number of issues and objectives underlying the choice of the proposed refunds mechanism.

- **Long-term incentives**. The stated intent of the refunds mechanism is to "incentivise long term maintenance activity which will minimise future risk to system security and system reliability." [RCCR, p. 90] In particular, there is a strong feeling that episodic refunds provide an insufficient motivation to provide a consistent incentive and that the lack of a consistent refund may lead to "free-riders." "The profile can be structured so the probability of the peak refund not applying at any time during the year is low and as a result delivers an incentive to undertake maintenance for all peak periods and reduces the risk that a participant may choose to risk avoiding exposure and not pursue an adequate maintenance regime." [RCCR, p. 95]

- **Short-term incentives.** A second stated intent is to "Incentivise short term behaviours to ensure day to day operation and maintenance activities are directed to maximising reliability at time of greatest value, generally when actual reserves are lowest." [RCCR, p. 90] It is interesting to note, however, that the short-term incentive is not really an incentive to make capacity available. "This is an important feature of the design, as it means refunds are (implicitly) directed at influencing plant reliability and maintenance performance, not the amount of capacity available to the Market per se." [RCCR, p. 95]
- **Fairness.** A key issue that arises is the differing treatment of baseload and peaking generators. "Due to the exposure of participants to refunds through Resource Plan shortfalls the current refund regime may create an imbalance in the exposure to refunds for participants with generators with differing utilisation rates." [RCCR, p. 90] Similarly, the proposal "provides a refinement that creates incentives for both short and long term scheduling of maintenance effort and more equitable treatment of different forms of capacity." [RCCR, p. 93] "As far as practicable all capacity providers should be treated equally." [RCCR, p. 103]
- **Level of refunds.** We understand the *level* of refunds overall to be an issue in the design of the mechanism. If the overall RCM is considered too generous, then a reduction in the level of refunds without a commensurate change to the RCM would make the RCM more generous. The temptation therefore is to design or adopt a modified refund regime that does not reduce the overall level of refunds. The alternative, which we recommend, is to view changes to the refund regime in the context of the outcome of a broader review of the RCM.
- **Volatility of refund revenues.** Volatility of refund revenues is also understood to be a concern. The issue of volatility arises in relation to the shape of the refund/reserve level relationship. "If refunds were based only on LoLP, refunds would be likely to fall to very low levels for reserve that was more than a relatively low margin above the largest unit, but would also lead to very high refunds well in excess of the current maximum level that applies in peak periods of summer. This would change the risk exposure and prudential risks in the market and should only be contemplated if it is clearly a net benefit – this not expected." [RCCR, p. 92]

In general, this seems like an appropriate list. Our main concern is with respect to the emphasis on maintaining the level of refunds and keeping down the overall cost of capacity. Forcing the cost of refunds to be above the associated economic cost of outages in order to achieve a "discount" to the cost of capacity has the potential to introduce other distortions that can undermine the effectiveness of the overall RCM. If the overall cost of capacity is too high, then other steps can be taken to bring that cost into better alignment with the economic value of capacity. The objective of keeping down the overall cost of capacity is best viewed as the purview of the RCM rather than the RCR regime, which is just a component of the overall RCM.

## 2.3. THE CAPACITY PRODUCT

The concept of reserve capacity is central to an understanding of the refunds regime and to the RCM itself. Capacity as offered into the RCM is a specific product. The rights and responsibilities associated with this product – and the associated payments and the allocation of costs – flow naturally from its definition. In order to provide clear guidance, however, it is crucial to define clearly what capacity is – and what it is not.

"The current capacity refund mechanism requires Market Participants (Generators) who have been paid for capacity (through Capacity Credits) to pay refunds if that capacity is not made reliably available to the market. The current capacity refund mechanism requires capacity refunds to be made if accredited capacity presented to market is less than (temperature adjusted) accredited capacity… Specifically the capacity refund mechanism requires a Capacity Credit holder to make repayments to the IMO if the capacity is not presented." [RCCR, p. 89]

The WEM, unlike the NEM in eastern Australia, can be characterised as a two-product "market". One product is sold through the bilateral energy market (and centralised balancing mechanism) that provides for the provision and delivery of energy in each hour. This capacity product may be bundled within a bilateral contract, or be provided via the centralised and administered capacity "market" associated with the RCM.[1] Given the existence of these two separate products, the requirement that capacity be made "available to the market" is a somewhat ambiguous statement. The fact that the obligation to make repayments exists in all hours – even when the possibility of shortage is virtually non-existent – suggests that there is some lingering expectation that the capacity procured through the RCM should be available to supply energy at all hours of the year.

In theory, however, this capacity product is entirely separate from the energy product. It does not provide for energy per se – that is the purpose of the energy market. The RCM is intended to compensate generators for providing capacity that is *able* to generate energy under situations of scarcity. Capacity as a separate product has no value at any other time.

These situations of scarcity are intermittent and occasional occurrences. While some capacity mechanisms have tried to compensate generators only during these conditions of scarcity, these markets proved ineffective. Accordingly, it has become common practice to provide capacity payments on an on-going basis throughout the year, as is done in the WEM through the RCM. As noted [RCCR, p. 88], "Like any contract the RCM has terms and conditions such as the flat monthly payment, refunds, the obligation to present capacity and to participate in coordinated maintenance planning."

Nonetheless, we must not confuse the terms of payment with the nature and value of the service being provided. While *payment* is continuous across the year, the *nature* of the service, and its intrinsic *value*, is episodic.

---

1 The RCM is technically better characterised as a "mechanism" and not a "market". The price and quantity of capacity procured does not adjust freely as they would in a market. Nonetheless, the RCM has a clear impact on merchant investment behavior in the WEM, so the use of the term "market" in this context is valid.

We must also distinguish the capacity in the RCM from the notion of "capacity" embedded into many bilateral contracts (or PPAs). These contracts give the buyer the right to purchase the energy from a generation facility whenever it is available at a price that approximates its dispatch cost. In return for this right, the buyer commits to a stream of "capacity" payments. Capacity in this sense is a bundled product. It not only compensates the generator for providing capacity that is able to generate under conditions of scarcity, but also provides compensation for the difference between the dispatch cost of the energy and its market value.

The capacity in the RCM is not intended to be a bundled product – it is pure capacity in the reliability sense. Because "capacity" in a bilateral contract is a bundled product, the contract must contain restrictions and incentives to ensure the provision of energy. The capacity product in the RCM needs no such requirements. To the extent that such restrictions or incentives are required, they are (or should be) established via the energy market.

The importance of the WEM as a two product "market" is that the value at stake when an accredited source of capacity fails to present itself depends entirely on market conditions (supply and demand) at the time. The simple failure to provide energy has no consequence for the capacity market except under shortage conditions.

## 2.4. Linkages with the RCM

The quantum of refunds payable is based on the administered capacity price. The administered capacity price is the subject of at least two on-going reviews, including the review of its constituent assumptions and parameters as well as our own review of the RCM in which we consider the basis for adjusting the administered capacity price to reflect the overall supply and demand for capacity credits. In our review of the RCM, we highlight how the current, essentially proportional, adjustment to the administered capacity price materially understates the extent to which the economic value of reserve capacity declines as the amount of excess capacity increases.

An economic-based adjustment in the administered capacity price to reflect excess capacity credits would make the administered capacity price more dynamic (and thus more volatile), but it would also have the impact of greatly reducing the penalty associated with capacity refunds during periods in which there is excess capacity. We think that this linkage should be an important consideration in the design of the RCR scheme. Changes should not assume continuity of the current administered capacity price.

## 2.5. Interactions between the RCR and the RCM

In concept, the "dynamic refund regime" is an improvement on the existing static scheme. However, the RCM and refund regime clearly interact in ways that shape incentives in the WEM. In this section we take a brief look at some aspects of the RCM and capacity refunds regime together:

1. The RCM pays generators for their full capacity, but then requires rebates in the event of forced outages.

- An improvement that would both sharpen the incentive for reliability and potentially address value transfer concerns is to pay generators for their de-rated capacity and allow them to earn credits or expose them to refund obligations depending on whether they exceed or fall short of "standard" performance. A "symmetric" regime in which there are rewards as well as refunds could be set up such that the *expected* level of *net* refunds is essentially zero. Such a "symmetric" approach would be a pure incentive regime;

- Failure to set refunds so as to fully reflect the cost of outages means that the refunds will not actually relate to the economic costs associated with failing to behave as intended. The current "asymmetric" approach means that an "economic" refund signal would introduce significant volatility but without any offsetting beneficial incentive to actually aim for better performance on average over time, as there is no potential reward for improved reliability above the certified capacity level;

- It has been noted that current capacity prices may diverge from the historical prices for capacity embedded into contracts. The current refund regime and the IMO's dynamic proposal involve value exposure for those generators whose contract capacity prices diverge from current market prices. This exposure would not exist (or would be much smaller) for a symmetric system.

- The asymmetric system relies on forced outage-related refunds in order to align the net cost of capacity with its value. Assuming all the parameters are set right, such a system might arguably work well for baseload generators, as these are likely to suffer forced outages on a regular basis. But it does not work well for peaking generators, since they are rarely called (and will be called even less often during periods of excess capacity)[2]. Ensuring equitable treatment requires the creation of some parallel means of valuing reliability (such as the operational testing). Under a symmetric system, peaking generators could be deemed to have a standard forced outage rate and compensated on that basis until they have enough dispatch events to estimate a specific forced outage rate.

2. The refund levels are far too low to act as appropriate short-term signals when capacity actually has value. Given the capacity price and a reasonable VoLL estimate, the annual LoLP should be on the order of 10-15 hours under equilibrium conditions. This suggests that the capacity refund should be 500-1000 times the average hourly capacity price under a loss-of-load situation. But the proposal caps the refund at 6 times the hourly price – two orders of magnitude lower than the potential outage cost. This refund level seems far too low to incentivise short-term behaviour in situations in which capacity has high value – which, of course, is the only time that these price signals are relevant.

2 Perversely rewarding peaking generators the most when they are valued the least.

3. The refunds apply only to capacity underage associated with forced outages. The value of capacity, however, is indifferent to whether an incremental MW arises by avoiding a capacity underage or creating an additional MW of capacity that was not otherwise being compensated under the RCM. If short-term price signals are to be used at all, there would appear to be no reason not to use them as an incentive to create additional capacity under shortage conditions when capacity has high value. While such short-term price signals could, in theory, create possibilities for the potential abuse of market power, the existence of the RCM contracts should act to mitigate such potential.

4. The desire to set charges low so as to minimise the volatility of refunds seems misplaced. In order to induce efficient behaviour, short-term signals should reflect the underlying value of capacity. If the volatility of refunds associated with such prices is truly a concern, then it may in fact be appropriate to institute some form of "insurance" to reduce this volatility. This could be done via a system analogous to "co-payments" for health insurance. In other words, rather than distorting the price signal represented by the refund price, part of this cost could be met via an insurance pool funded by generators making payments proportional to their forced outage rates. In the event of an outage, the majority of the refund would be paid by the insurance pool; the generator itself would make a much smaller payment. Note that the "symmetric" structure described above effectively creates such an insurance pool.

5. If refunds are to recover the expected cost of outages, setting the refund levels far below the outage cost under true shortage conditions means that charges must be set above the true cost of outages in many more hours. While there is some benefit to spreading the charges out across enough hours so that they are not simply a random and episodic price signal, spreading them across too many hours creates a diffuse short-term price signal that fails to reflect the true outage cost.

# 3. RECOMMENDATION

The proposed dynamic regime is an improvement on the existing regime in that it does incorporate market conditions in the setting of the refunds. Implementing the proposed dynamic refund regime without making any other changes to the RCM itself, however, would have the effect of reducing refund exposure to generators. We therefore recommend consideration of the refund regime only in the context of the broader review of the RCM.

A change to just the refund regime in the direction of the proposed dynamic refund scheme would result in a perverse outcome. Generators would implicitly receive a higher "expected value" of capacity at a time when the economic value of reserve capacity is nearly zero. A more integrated solution would be to link changes to the refund regime to changes in the RCM itself. A consistent change, for example, would see the introduction of a more market-based price paid by the IMO for capacity credits. In a period of excess capacity, that price would be lower. That lower price would also flow through to the capacity refunds regime.

Other possible changes to the refunds regime include adding a symmetric aspect to it such that penalties for failure to present capacity can be offset to a degree by the ability to present more capacity than has been accredited. A derating-based refunds regime could then be constructed in which the cumulative value impact of the refunds would be essentially zero over the course of a year, but the desirable incentive aspects would each be enhanced. Such a refund regime would make the most sense in the context of possible changes to the RCM to introduce more economic pricing of those capacity credits that are not traded bilaterally.

We caution against early adoption of the dynamic refund regime even though it is clearly an improvement to the current static regime. Instead, we recommend that the IMO explicitly consider the interactions between the RCR scheme and the RCM and coordinate proposed changes.

# Independent Market Operator

# Review of Capacity Cost Refunds

## Date: 5 April 2011

# Contents



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# 1. PURPOSE

The Rules Development Implementation Working Group's (RDIWG) terms of reference[1] includes the consideration, assessment, development and post-implementation evaluation of a number of design issues. One of the design issues identified for consideration by the RDIWG relates to capacity refunds in the Wholesale Electricity Market (WEM):

> **Issue 4:** At different times the capacity refund arrangements under and over price the value of capacity leading inefficient decisions by participants about the timing of maintenance and presentation of capacity.

The roles of refunds and how they fit within, and affect, the broader set of market incentives have been presented in a number of previous presentations and papers[2]. The purpose of this paper is to present the outcomes of the IMO's review of the current Reserve Capacity refund arrangements within the wider context of the RDIWG's scope of work. The impact of capacity refunds on the incentives for timely commissioning and reliability performance of facilities are specifically considered. The distribution of refunds is also addressed including the current methodology in the Market Rules and alignment with other capacity processes in the Market and the lumpy nature of the cost of Supplementary Reserve Capacity.

# 2. BACKGROUND

## 2.1 The Reserve Capacity Mechanism

The Reserve Capacity Mechanism (RCM) is a central feature of the design of the WEM. Relevant key characteristics of the design and operation of the RCM and its interaction with arrangements for energy trading are:

- A price ($/MW) for capacity is determined and reviewed annually;
- The IMO determines the minimum Reserve Capacity requirement three years in advance;
- Asset owners seek accreditation for capacity to meet the IMO's requirement;
- The Market Rules employs a safety net auction process if insufficient capacity seeks accreditation;
- IMO makes flat monthly payments for accredited capacity at rates referenced to the annual capacity price (or offsets retailer obligations where a retailer has an approved contract with an accredited reserve provider);
    - Accredited capacity must be presented to market unless exempted for a defined maintenance outage approved by System Management;
    - Under the Market Rules the IMO settlement processes deduct capacity refunds in the event accredited capacity is not presented and has not received prior approval for a maintenance outage;

[1] See: http://www.imowa.com.au/f139,788900/RDIWG_Terms_of_Reference_20100901.pdf
[2] For example, refer "Market Rules Design: Problem Statement" available: www.imowa.com.au/RDIWG

- The current design of the capacity refund mechanism is focused on reliability at times of expected peak demand and is shaped accordingly[3] and has implications for the commissioning of new facilities;
- The capacity refund mechanism incorporates a cumulative cap that minimises the exposure of individual participants to a level equal to the amount the generator paying refunds could earn in a Capacity Year;
- Accredited new entrant capacity is required to lodge a security deposit with the IMO that can be withheld in the event the capacity is not presented in accordance with its performance measures within the Rules;
- If a security deposit is withheld it is distributed to Market Customers in a similar ratio to the obligation to fund capacity payments;
- In the event the IMO forecasts the minimum capacity reserve will not be met due to either a lack of response from new entrants or failure of in service facilities the IMO may purchase Supplementary Reserve Capacity (SRC). Market Customers are required to fund SRC purchases through an additional charge at the time of the SRC purchase;
- More generally:
    - The RCM operates in conjunction with energy and Ancillary Service arrangements though the Net Stem Shortfall calculations in the Market Rules;
    - Capacity in the RCM is presented to market on an interval by interval basis (with an allowance for planned outages) either though nomination of bilateral contracts and/or by offering capacity to the market at the Market Participants Short Run Marginal Cost (SRMC);
    - Energy provided by accredited capacity is traded under:
        - bilateral contracts and a day ahead short term market that provides a mechanism for participants to increase or decrease level of contracts, and
        - on-the-day balancing of variations in supply or demand from day ahead net contract positions.

In reviewing arrangements for capacity refunds and SRC charges it is important to consider their role within the design of RCM and more broadly within the WEM. As this paper is limited to consideration of the refund regime and closely related SRC charges it will consider other aspects of the design to the extent needed to ensure internal consistency across the design of the market as a whole. This will allow more focussed consideration of the performance of the refunds and expeditious consideration of any potential changes that may be identified.

### *2.2 The RCM and Reserve Capacity Refunds*

The RCM is a key part of the WEM design and provides a framework for relatively tight management of reliability. A useful way to view the RCM is to consider it as a contract with the IMO on behalf of customers. Like any contract the RCM has terms and conditions such as the flat monthly payment, refunds, the obligation to present capacity and to participate in

[3] See clause 4.26 of the Market Rules.

coordinated maintenance planning. Also, like many contracts the terms and conditions are designed to elicit delivery of a product or service to a defined quality and it therefore includes incentives designed to make this happen. The refunds are a key part of the incentive mechanism within the "contract". They are commercial in nature and provide price signals to incentivise performance.[4]

The current capacity refund mechanism requires Market Participants (Generators) who have been paid for capacity (through Capacity Credits) to pay refunds if that capacity is not made reliably available to the market. The current capacity refund mechanism requires capacity refunds to be made if accredited capacity presented to market is less than (temperature adjusted) accredited capacity:

- as a result of (unplanned) Forced Outages; or
- where a Market Participant presents to Market less capacity than is required, accounting for Reserve Capacity Obligations, Forced Outages and the Capacity made available to the Market in each trading interval

Specifically the capacity refund mechanism requires a Capacity Credit holder to make repayments to the IMO if the capacity is not presented[5]. The refund is currently set on a time based schedule within the Market Rules and weighted to times when high demands are more likely when reserves may be low and the potential risk to reliability highest. The weighting is achieved by setting the refund to a multiple of the payment that the capacity provider will receive over the period of reduced capacity. The refund creates a financial incentive for capacity providers, without an approved outage, to ensure capacity is made reliably available during times when the potential threat the system reliability is highest.

The refund regime provides for Market Participants to perform controllable maintenance at "acceptable" times, as a Market Participant may apply to System Management to undertake a Planned Outage. Planned Outages can include on the day Opportunistic Maintenance (clause 3.19.11 of the Market Rules). During a Planned Outage the capacity provider is exempt from exposure to capacity refunds. A number of criteria must be met prior to System Management's approval of the Planned Outage or Opportunistic Maintenance (outlined in clause 3.19.6 of the Market Rules). Additionally, System Management may reject a Planned Outage at any time where they consider there will be a risk to system security or system reliability (clause 3.19.5).

A consequence of exempting participants with in-service Facilities from exposure to refunds, in the case where they have not received outage approval, the behaviour that the refund is most likely to influence is:

- the reliability of plant in service and expecting to generate to its resource plan; and
- the cost and effort exerted to return plant to service from a forced outage.

This is an important feature of the design, as it means refunds are (implicitly) directed at influencing plant reliability and maintenance performance, not the amount of capacity available to the Market per se.

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[4] To extend the contract analogy further, the refunds are a commercial mechanism rather strict terms of delivery that could be breach of contract in other contexts.

[5] The current structure of the Market Rules requires the IMO to pay this refund amount to Market Customers proportional to their IRCR

# 3. ISSUES AND POTENTIAL FOR IMPROVEMENT

## *3.1 Introduction*

The intent of an effective capacity refund mechanism can be described as to:

- Incentivise **long term maintenance activity** which will minimise future risk to system security and system reliability; and
- Incentivise **short term behaviours** to ensure day to day operation and maintenance activities are directed to maximising reliability at time of greatest value, generally when actual reserves are lowest.

To be of any value the parties exposed to a price signal such as a capacity refund should be capable of responding to it. In addition if a signal is to be economically efficient it needs to be capable of being used by participants to weigh up their internal (private) costs and benefits and to make decisions that have a net benefit to the market as a whole (public benefit).[6]

The current capacity refund mechanism creates incentives for capacity providers to manage their long term decision making processes around appropriate maintenance schedules by clearly defining the periods where the greatest potential system need for capacity at peak times occurs (during the Hot Season). However, as will be discussed further below, not all hours or days within periods of greatest *potential risk* to system security and reliability will have the same *actual* level of risk. Furthermore the times of (relatively) lower risk in peak periods (e.g. mild summer days) offer opportunity for short term maintenance to reinforce reliability for peak conditions.

Additionally, due to the exposure of participants to refunds through Resource Plan shortfalls the current refund regime may create an imbalance in the exposure to refunds for participants with generators with differing utilisation rates. For instance a base load generator will be exposed to refunds in practically every interval of the year while a peaking generator will only be exposed to refunds when dispatched.

## *3.2 **Refund Rate v Reserve under the status quo***

As the current regime includes different levels of incentive for different times, it is useful to review how well the refunds aligned with actual conditions: in particular to assess if the incentive created by the refund was strongest when reserve was low and weakest when it was high. The next two plots provide different views of the actual reserve and refund factor over the 2009 calendar year.

[6] Where a price is simply recovering a cost it should be applied in a way that does not create unintended distortions

**Figure 1 Cal 2009 Refund Factor v Reserve**

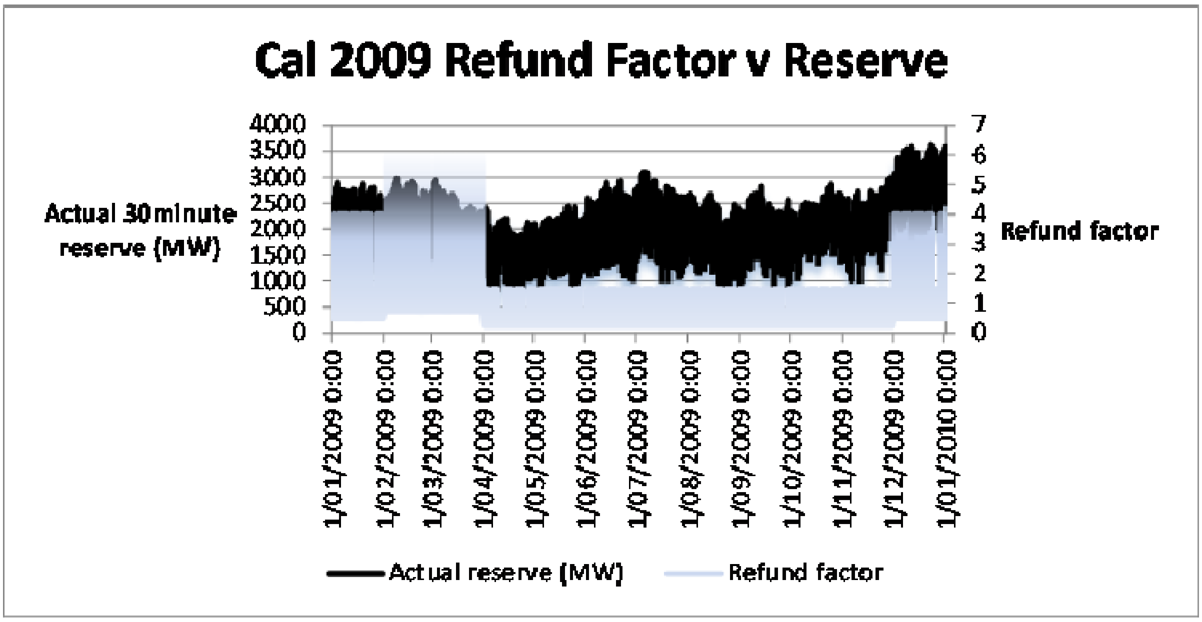
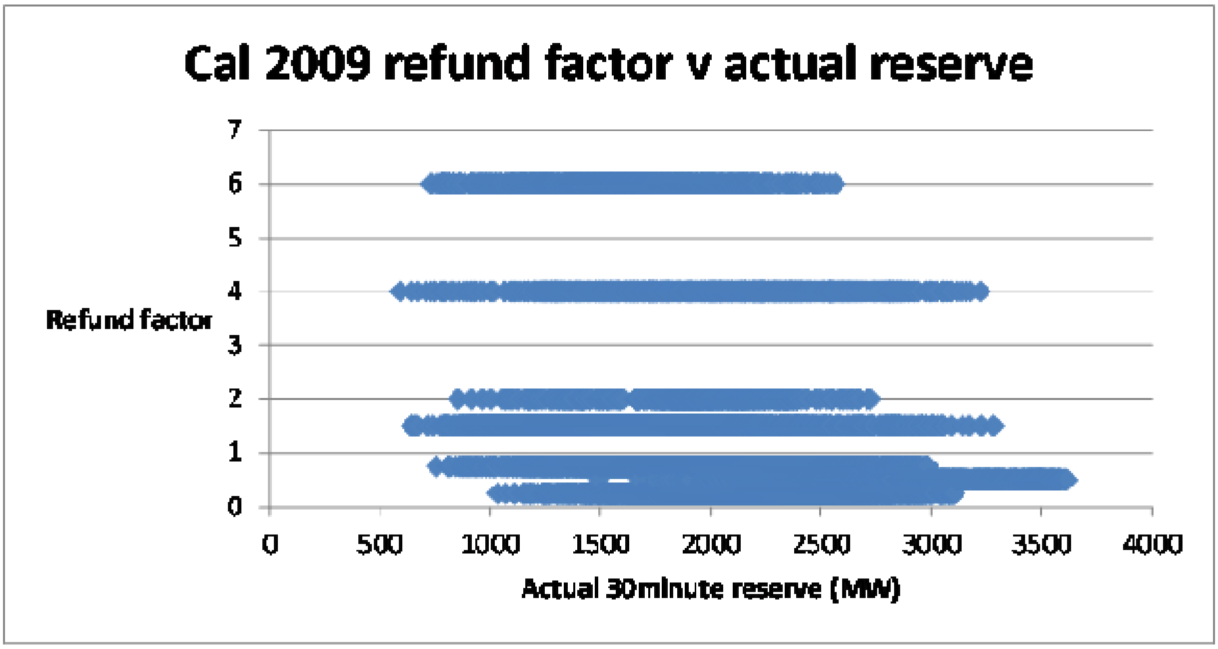



Figure 1 shows actual reserve in solid base plot (as the data covers the entire year only the envelope of maximum and minimum values is readily seen). Figure 2 shows the range of refunds for different reserves across the year. The highest refund rate of 6 applied some of the times of low reserve (as is intended), but factors of 4 and 1.5 also applied for instances of low reserve observed during the year (seen by reading the different levels at the left hand end of the range of reserves). At the low refund end, the highest reserve (3600MW) occurred when the second lowest refund level applied (0.5). The highest reserve occurred when the lowest refund factor (0.25) applied was 3100MW, 1.6 times the largest generating contingency less reserve than the maximum reserve.

**Figure 2 Cal 2009 Refund Factor v Actual Reserve**




Overall, the current profile and exposure to refunds creates clear long term signals that align with the possible extreme conditions – for example the refund is highest in day light hours in summer and weakest when high reserve is most likely. This can be seen from the broad shape of Figure 2 showing lower refund for higher reserve in general (slight negative correlation evident). However, there are many exceptions that suggest there may be scope for amendment.

## 4. POTENTIAL SOLUTIONS

Short term risk to reliability of supply can be measured by the Loss of Load Probability (LoLP). However, if refunds were based only on LoLP, refunds would be likely to fall to *very low levels* for reserve that was more than a relatively low margin above the largest unit, but would also lead to very high refunds *well in excess* of the current maximum level that applies in peak periods of summer. This would change the risk exposure and prudential risks in the market and should only be contemplated if it is clearly a net benefit – this not expected. It would also require acceptance that long-term incentives relating to maintenance programs was entirely reliant on short term risk.

Two broad forms of amended arrangement designed to address both short and long term objectives are discussed below. These are:

1. A dynamic refund rate based on the reserve available in any particular interval; and/or
2. A refund rate based on a dynamic reserve calculation overlaid with longer term factors.

Ultimately it is assumed that a regime based on a dynamic calculation of the refund rate and actual reserve with a cap on the maximum refund (potentially set at the same level as the current regime) is a pragmatic translation of the current regime. In conjunction with changes to the exposure to refunds described below this will provide a refinement that creates incentives for both short and long term scheduling of maintenance effort and more equitable treatment of different forms of capacity.

### *4.1 Basic reserve related refund*

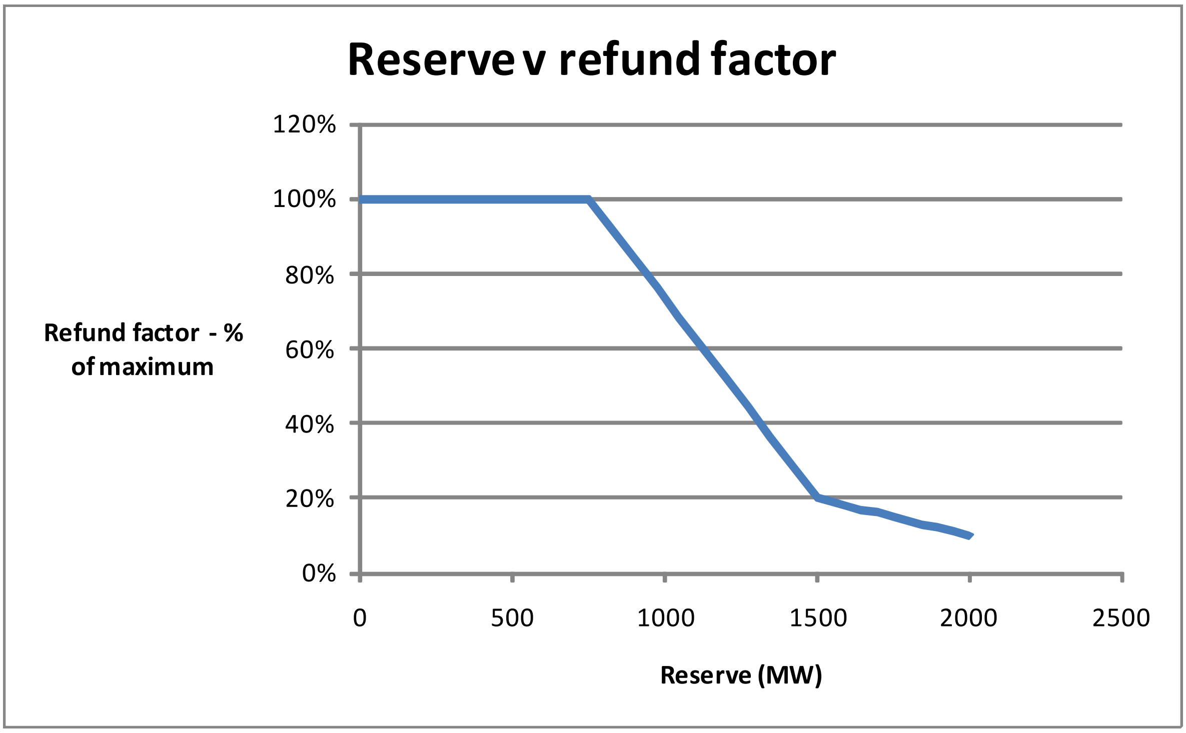
The first alternative is a simple regime that is responsive to prevailing conditions and would:

- Involve a refund rate determined from a series of breakpoints on a reserve versus refund factor relationship;
- The refund factor would be capped – the cap will limit prudential and commercial risks to participants;
- Include a lower minimum floor level to apply once reserve rises to more than a nominated factor above the minimum capacity requirement; and
- A further breakpoint at a higher level of reserve with a very low level of refund (possibly 0).

Compared to a purely short term LoLP based approach the resulting refunds will be far flatter and show a lower refund under lower reserve but higher under moderate to low reserves (for example n the range of 750MW -1500MW at peak times on hot days).

Figure 3 illustrates the relationship using potential breakpoints broadly based on the minimum reserve requirement.

**Figure 3 Reserve v Refund Factor**




### *4.2 Combination actual and annual forecast reserve*

Another approach to the balance between long and short term activity would see an annual factor based on a measure of annual reserve level applied to the simple dynamically calculated interval factor such that in years with lower reserve the annual factor would lift all refund rates reflecting the higher value of capacity.

This is a more sophisticated approach designed to be more responsive to both long and short term conditions. There are two broad approaches that the annual factor could be based on:

1. historical outages/availability; or
2. forecasted outages/availability

Of the two approaches to setting the annual factor under such a scheme an assessment of likely actual reserve (forecast method) appears more robust as the reason for poor performance in a previous year may have been because of intensive maintenance (planned or forced) that will see good performance in the year in question. However, it is also notable that reduced performance in any year will see lower system wide reserve on more occasions under all conditions.

The basic reserve refund concept is backward sloping and thus longer time with lower reserve will automatically result in a higher refund rate. On this basis the combination alternative has not been pursued.

### *4.3 Combination forecast and actual reserve related refund*

More complex versions which sit between the two methods outlined in sections 4.1 and 4.2 of this paper could see the refund set on the basis of combination of forecast reserve and actual on a more granular level. For example it would be possible to set an "importance" factor for each month where this factor would be a reflection of the relative risks shortage of capacity in that month poses to system security and reliability. The maximum reserve capacity multiplier would then be scaled in each month depending on the "importance" of the month.

Clearly there would be opportunities to adjust the factors to change the percentage of ex ante and ex post and the relationship with forecast and actual reserve and also to change the cap and floor levels. While such an arrangement would provide a more sophisticated approach it would also be more complex. On balance that complexity does not seem warranted at present in light of the improvements that can be achieved from a simpler option.

## 5. IMO PROPOSED SOLUTION

The IMO considers that, on balance, the basic reserve related refund approach will provide an appropriate mix of long and short term incentives. This method is responsive to prevailing conditions and creates incentives for appropriately timed maintenance. The profile can be structured so the probability of the peak refund not applying at anytime during the year is low and as a result delivers an incentive to undertake maintenance for all peak periods and reduces the risk that a participant may choose to risk avoiding exposure and not pursue an adequate maintenance regime. In years with surplus capacity the hours of exposure to the higher rate will be less and conversely will be higher in years with low reserve.

However, it should be noted that in any realistic scenario there will always be significant exposure to the capped factor.

To assist participants to assess the risk of exposure to refunds the IMO would publish forecasts of the likely reserve over a long horizon and the potential refund rate that a market generator would be exposed to in those situations. The forecasts would likely use the MT PASA for long term projections, the ST PASA for a more granular short term indication of likely refund rates, and finally, the day ahead forecasts to help participants make real time maintenance decisions.

### *5.1 Defining the magnitude and profile of the dynamic regime*

This section considers the design of a basic dynamic refund *v* reserve arrangement in more detail. Design of a refund arrangement can be divided into consideration of three issues:

- The profile of refund or how well the relative refund under different conditions aligns with the incentive that the design is attempting to create. This is about the relativity of net payment for capacity under different conditions;
- The magnitude of refunds within the profile; and
- Exposure of participants to refund.

This next sections deal with how the first two of these dot points could be defined under the proposed methodology while section 6 of this paper deals with exposure.

### *5.2 Cumulative Refund Cap*

The IMO considers that there is no need to change the current cap on cumulative refunds that can be imposed in a period under the Market Rules, for example when commissioning of a new unit runs late.

However, if the cumulative refund limit were to be retained at its current level then the financial consequence of a delay in commissioning of a new unit may be less. This is because the actual reserve during the delay period would most likely not be at the maximum foreshadowed in the current regime at all times and the refund would be lower at those times. This would depend on how severe the resultant loss of aggregate capacity was and for the reasons outlined earlier mean that the refund factor would be higher more often than if the plant did commission on time counteracting the lower refund factor to some extent.

### *5.3 Analysis: Status Quo Compared to Dynamic Mechanism*

Analysis of refunds under the existing design and also under an illustrative setting for the "Basic Reserve Related Refund" is presented below. The analysis has been conducted for the 2008 and 2009 calendar years.

The results show that while there were marked differences between the results for the two years it is notable that taken over the longer term the cumulative refunds across the market were similar under the two approaches (with the profile set as described in section 5.4). These effects are shown in

Figure 4 through to 10. In Figure 6 the effect of different monthly refund base capacity payments is evident and results in some spread of refund rates for the same reserve.

**Figure 4 Comparison of cumulative total refund: calendar 2008**

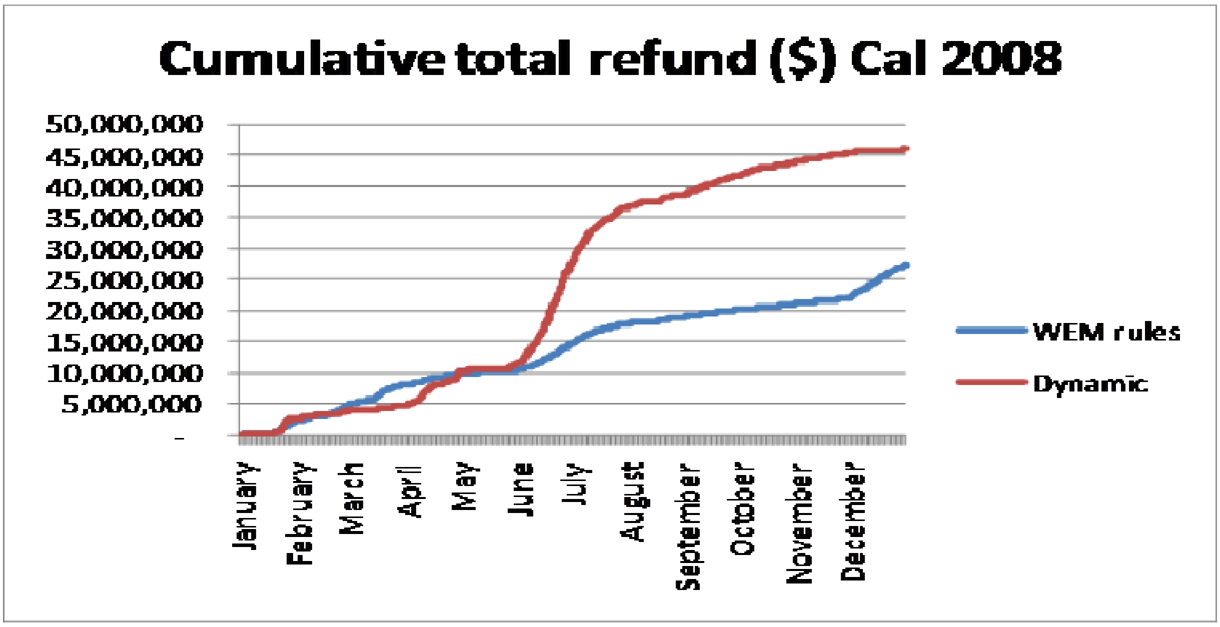



**Figure 5 Refund rate versus reserve in calendar 2008: WEM rules**

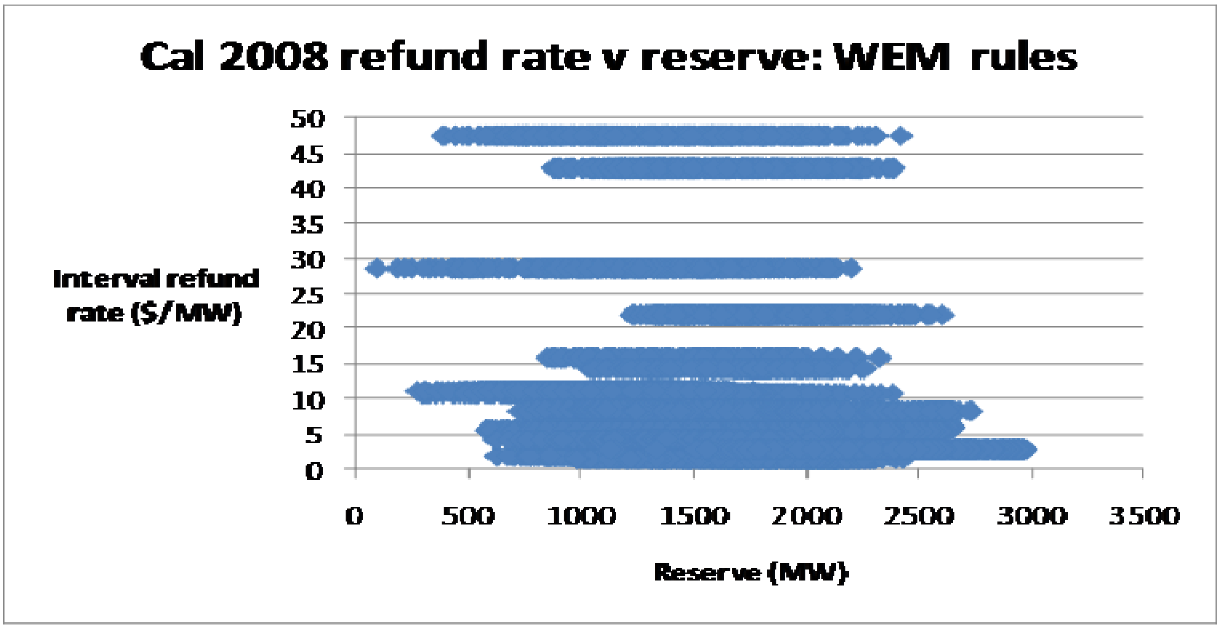


**Figure 6 Refund rate versus reserve in calendar 2008: Dynamic settings**

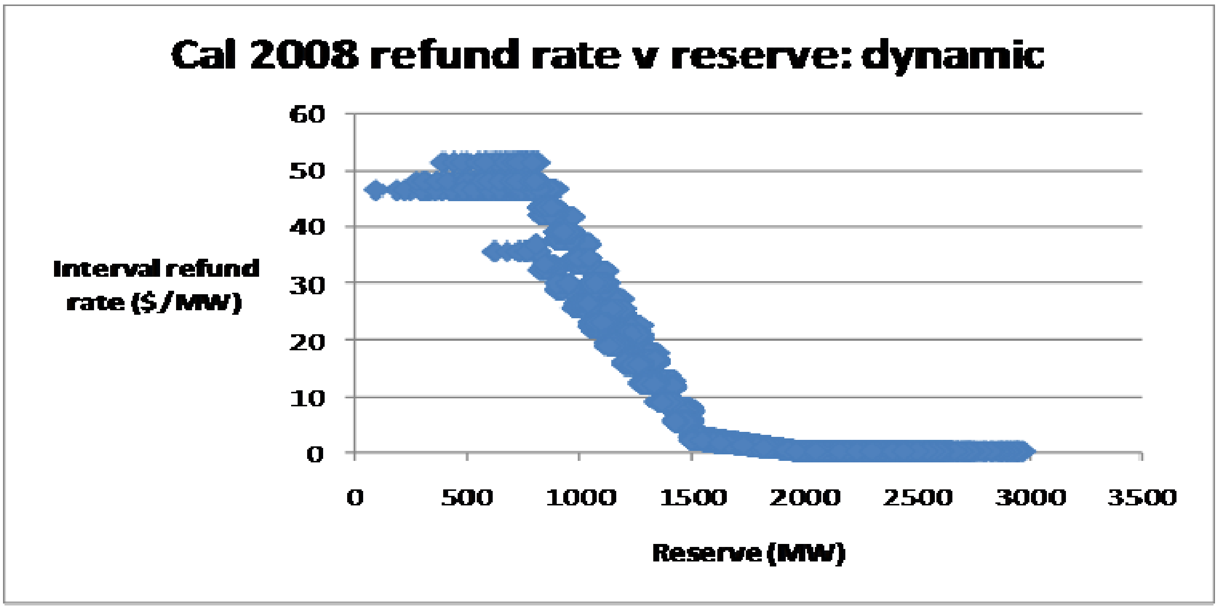



**Figure 7 Comparison of cumulative refunds: calendar 2009**

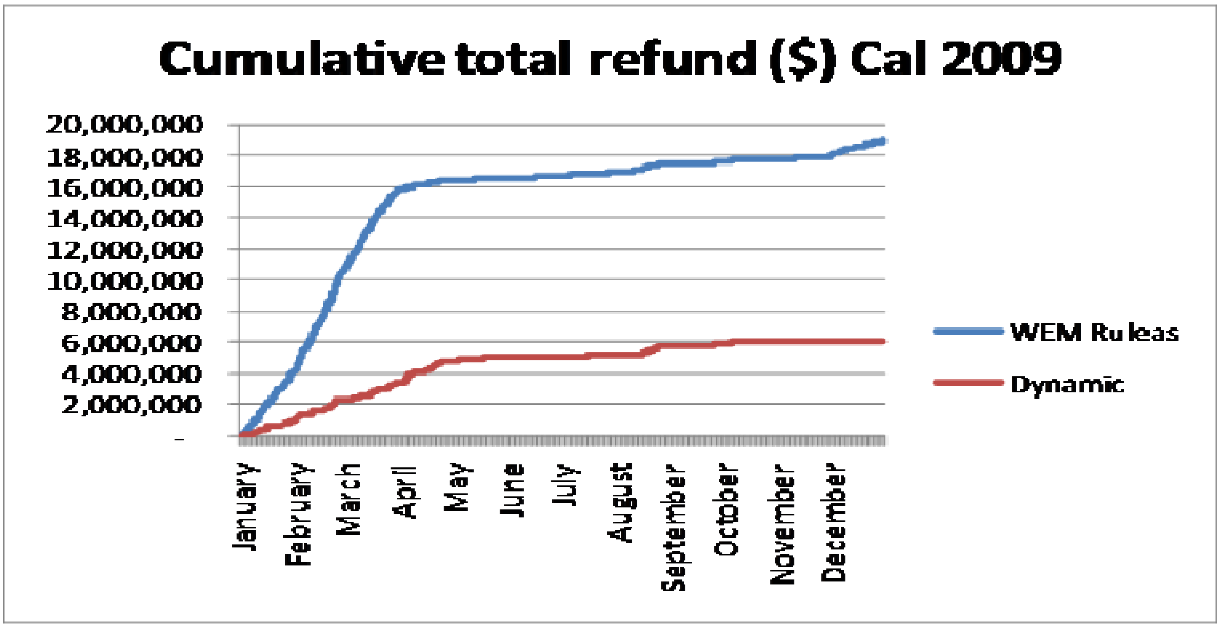


**Figure 8 Refund rate versus reserve in calendar 2009: WEM rules**

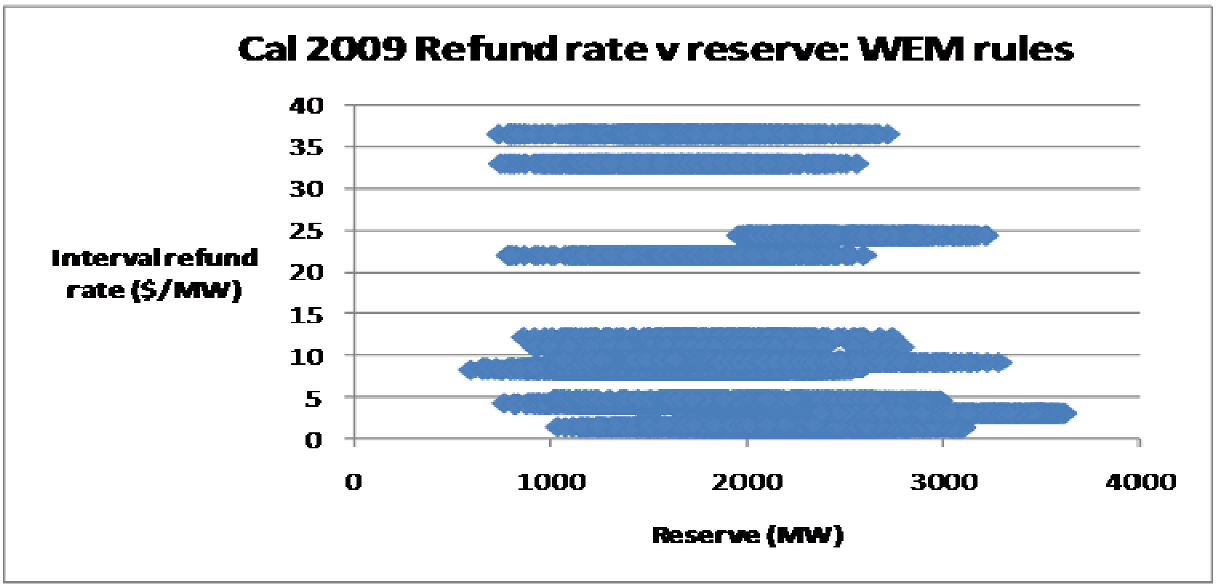



**Figure 9 Refund rate versus reserve in calendar 2009: dynamic settings**

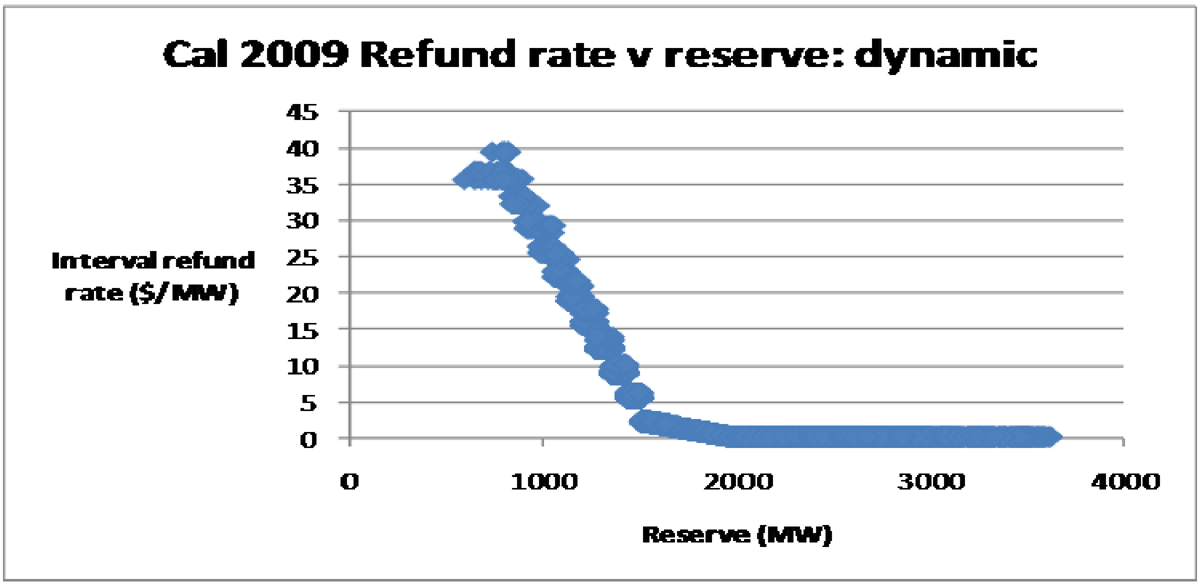



Figure 4 and Figure 7 show that across the year refunds can be higher or lower under the dynamic regime compared to the current WEM rules. Interestingly, over the two years studied the current refund rules were introduced the total refund is approximately the same.

The key point is that under the “Basic Reserve Related Refund” regime the refund rate ($/MW) is a function of reserve and thus value at the time.

### 5.4 IMO Proposed Solution

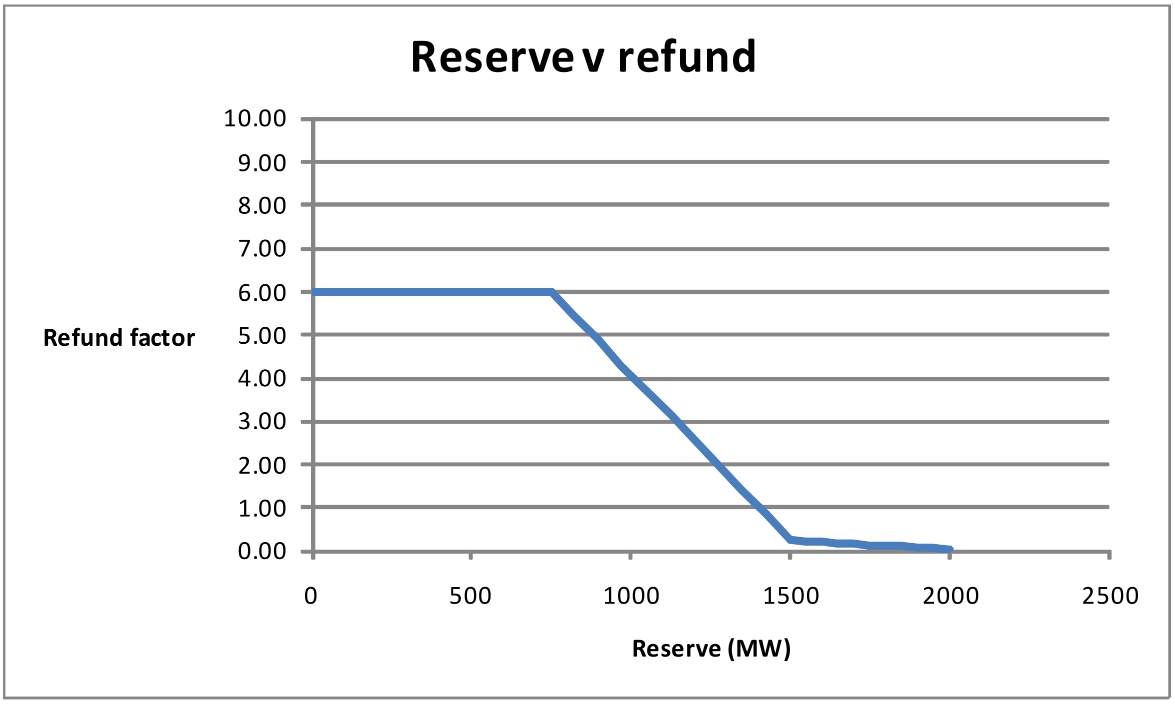
The IMO proposes that the maximum refund factor remain at the maximum value of 6. As noted analysis of the 2008 and 2009 calendar years shows that the cumulative refund amounts under the Market rules and the proposed methodology are similar. The IMO considers that as the design is aiming to produce a pragmatic balance between long and short term incentives a different level of maximum refund factor may not necessarily yield a more efficient or effective result although there is an element of choice about the level adopted. The current defined maximum level of 6 is yielding a level of refunds that is established in the Market and as noted delivers similar to outcomes over a year.

The IMO proposes to set the profile of the refund regime so that:

- The capped refund factor that would apply whenever reserve was below a nominated percentage of the minimum capacity reserve is to linked the required minimum reserve used by System Management in outage planning, say 2*min reserve ~ 750MW;
- the lower minimum floor level to apply once reserve rises to more than a nominated factor above the minimum capacity requirement be set equal to 4* min reserve ~ 1500 MW; and
- the final break point be set such that the refund factor is set to zero when the reserve is greater than 6 * min reserve ~ 2000MW.

Figure 4 illustrates the relationship using the breakpoints noted above.

**Figure 10 Reserve v Refund**



## 6 EXPOSURE TO REFUNDS

The sections above have considered amendment to the refund rate. This section considers the exposure to the refunds in two respects.

The first is that, as noted earlier there is an imbalance in the exposure to refunds that depends on the utilisation of the facility in question – the lower the utilisation the lower the risk of exposure.

The second relates to the mechanism for identifying the conditions under which refunds should be imposed. The Market Rules require the payment of a refund where a Market Participant presents to Market less capacity than is required, accounting for Reserve Capacity Obligations, Forced Outages and the Capacity made available to the Market in each trading interval. This shortfall in capacity is captured in the Net STEM Shortfall calculation in the Market Rules. Analysis of the 2008-09 and 2009-10 Reserve Capacity Years indicates that historically the Net STEM Shortfall refunds, as a proportion of total refunds, were 5.1% and 6.5% respectively (see Figure 11 Forced Outage v Net STEM Shortfall Refund). It is clear that the bulk of the refunds by participants are made due to forced outages. The Net STEM Shortfall refunds only represent a small proportion of the refunds but in practice is not technology neutral. This is because resources with low operating costs are more likely to be dispatched at any given time and thus more exposed to risk of refund due to what may be normal variations in operation of their plant whereas other low utilisation technologies are only subject to refund on the basis of a more controlled test.

Adjusting the figures to remove the impact of the late entry of the Griffin Bluewaters 1 facility in the 2008-2009 Reserve Capacity Year does yield slightly results; though does not exhibit an inconsistent trend. The contribution of the Net-STEM shortfall in the 2008-09 and 2009-10 Capacity Years are 9.1% and 6.5% of total refunds. Monthly breakdowns are exhibited in Figures 13 and 14. Figure 15 shows the relative cumulative contributions from both the Net-STEM shortfall and Forced Outage refunds. Adjusting for the effects of the Griffin Bluewaters late entry drastically changes the quantum of the refunds that were paid to the market in the 2008-2009 Reserve Capacity Year and bring its into line with the following Capacity year where no late entry of facilities occurred.

Figure 11 Forced Outage v Net STEM Shortfall Refund

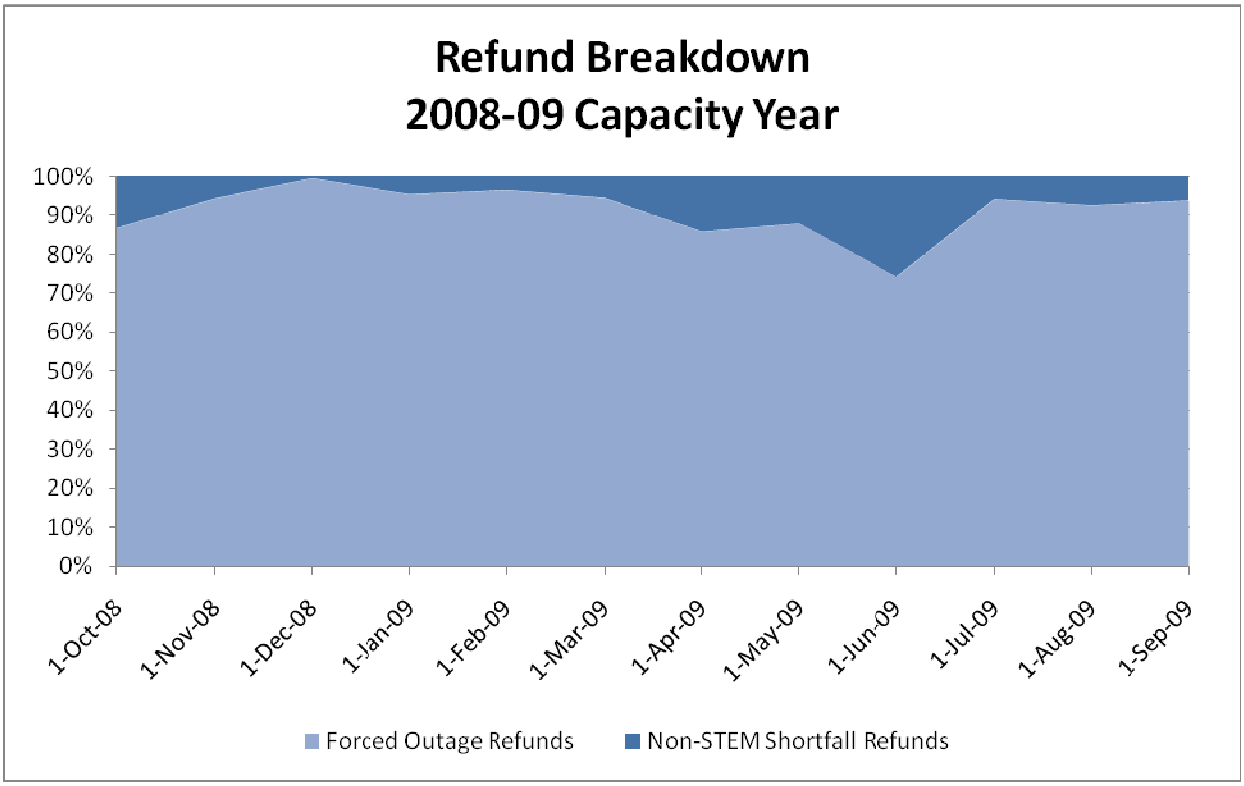



Figure 12 Forced Outage v Net STEM Shortfall Refund

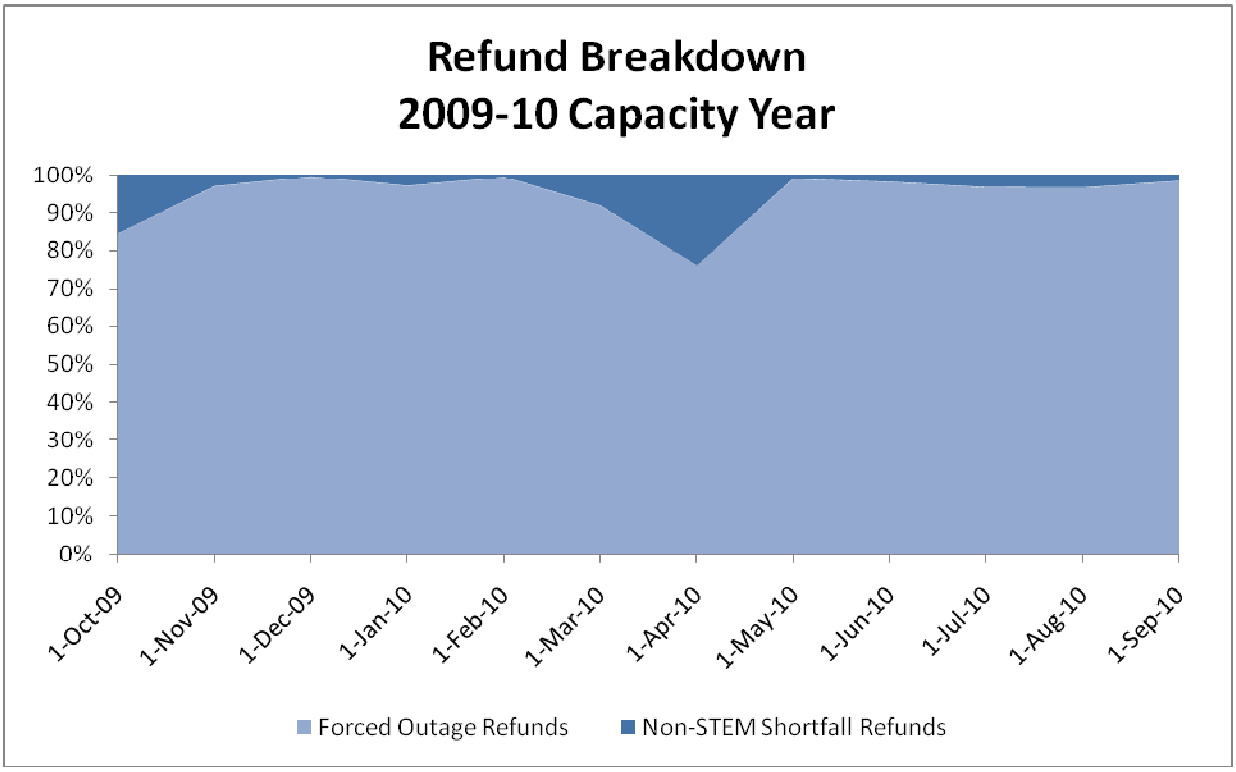


Figure 13 Forced Outage v Net STEM Shortfall Refund (Griffin Adjusted)

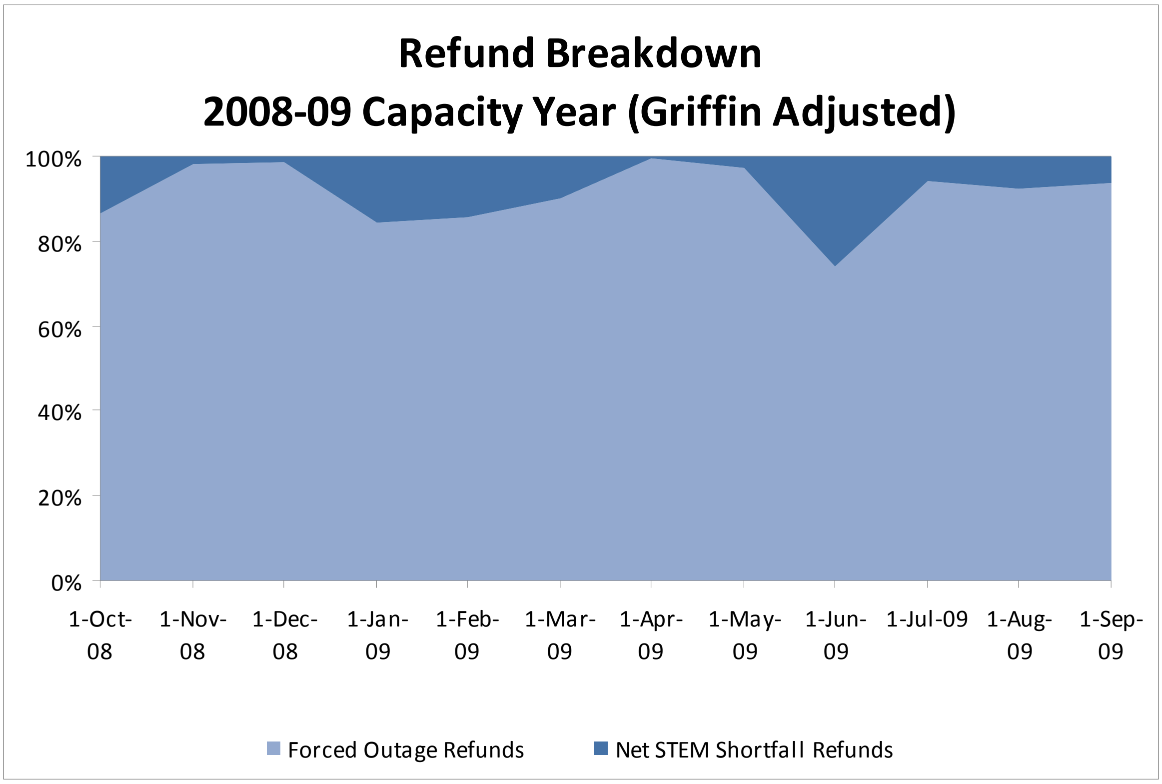



Figure 14 Forced Outage v Net STEM Shortfall Refund (Griffin Adjusted)

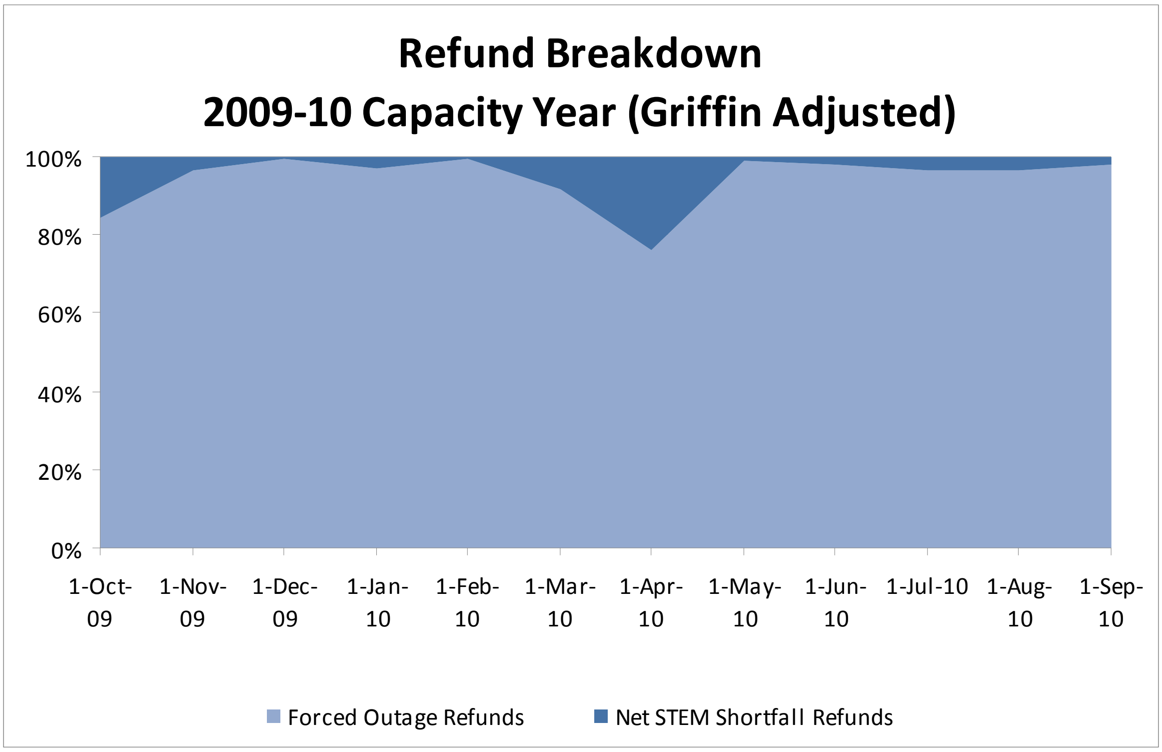
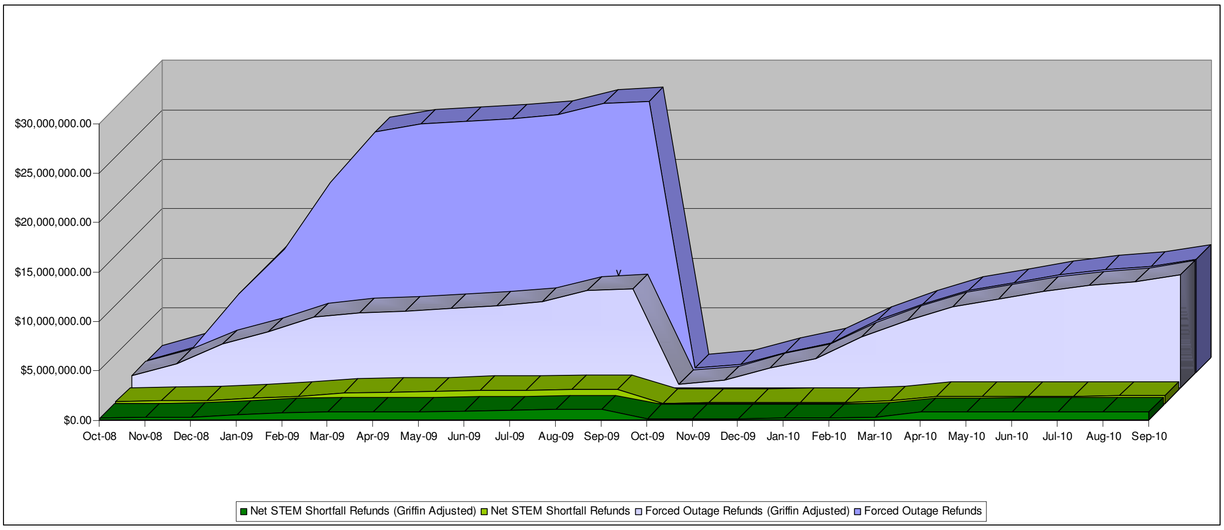


Figure 15 Cumulative Forced Outage and Net-STEM Shortfall Refunds (Per Capacity Year) - Normal and Griffin Bluewaters Adjusted




In reviewing exposure it is useful to note that exposure is a matter of policy rather than analysis and the following principles and mechanisms are proposed for the future:

- As far as practicable all capacity providers should be treated equally;
- All holders of accredited capacity should be required to declare the level of capacity being presented to market each day.
    - The declared amount should only be less than the accredited capacity if System Management has approved a planned outage (see below) plus any amount declared as a forced outage.
    - Approval should be reviewed/confirmed on a daily basis prior to the declaration.
    - The declaration can be part of the STEM submission process but should be a separate and formal declaration on behalf of the business.
- Refunds should only be imposed as a result of a declared Forced Outage or a failure to pass an "Operational Test".
    - The "Operational Test" should be designed to confirm available capacity when there is a reason to believe it may not be available and is a consequence of moving from an automatic exposure regime to a compliance and surveillance regime. Provisions for the conduct of an Operational Test should not create an unnecessary burden on System Management as the test is essentially a commercial and compliance measure rather than a real time dispatch mechanism;
    - To that end failure to follow a resource plan for a short period should not automatically result in exposure to a refund. The reason for this is that it is within good industry practice for generating units to exhibit some variability in output in the short term. Generation businesses should be expected to seek to

operate each unit in the most efficient manner to meet a target output – in the WEM the resource plan. Variation for minor operational fluctuations is not a definitive indication that the unit would not pass a test of the same sort that a unit that is available but not operating at the time would.

- Clearly failure to reach or maintain full resource plan level of operation is an indication the unit MAY not pass such a test.
- The Operational Test would be conducted either
  - in real time by System Management; or
  - Ex-post by the IMO.

  Each of the above options has differing pros and cons, however a threshold for testing would need to be established and would be considered in the detailed design of rule amendments including that there will be an interaction between calling for a test and emerging changes to arrangements for balancing and ancillary services and the resultant implications for System Management control room activities.
- More surveillance resources will be required for this to work:
  - this may be in the form of an automated system for system management and the requirement for system management to call such tests in specific situations; or
  - more staff and/or IT systems for the IMO to monitor the resource plan deviations of market participants and co-ordinate the testing with SM.

Further refinements may also be possible within the general principle in respect of provisions for opportunistic maintenance and the notice period for approval of maintenance outages ex post. The IMO proposes that, if time permits, this area be developed further as part of the rule change process needed to implement amendments arising from this proposal.

### *6.1 IMO Proposed solution*

The IMO proposes that Net STEM Shortfalls be removed from the Market Rules as a basis for imposing Capacity Refunds.

Further that Capacity Refunds should only be imposed as a result of a declared Forced Outage or a failure to pass an "Operational Test" as outlined in the previous section.

## 7 DISTRIBUTION OF RESERVE CAPACITY REFUNDS

This section reviews the arrangements for the distribution of Reserve Capacity Refunds received by the IMO and looks at the sources of funding of Supplementary Reserve Capacity (SRC) and proposes an amendment, including the formation of a fund available to be used in the event the procurement of SRC is required in response to a shortfall in capacity in the Wholesale Electricity Market.

### *7.1 Current Arrangements*

Reserve Capacity Refunds are currently collected by the IMO under two circumstances:

- if a Market Participant lodges notice of a forced outage with System Management. Forced outages attract a refund, per trading interval, of the amount that would have been paid by the IMO for the provision of the capacity (capacity payment) multiplied by the refund factor defined in the refund table (Market Rule 4.26.1) for which an amendment has been proposed in paragraph 5.4 above; and

- where a Market Participant presents to Market less capacity than is required, accounting for Reserve Capacity Obligations, Forced Outages and the Capacity made available to the Market in each trading interval - this type of deficiency is termed a Net STEM Shortfall which the IMO is proposing be removed from the Market Rules as a basis for imposing Capacity Refunds .

The sum of these payments over a trading month represents the total amount collected relating to Reserve Capacity Refunds. Reserve Capacity Refunds are distributed to Market Customers consistent with the principle that they are responsible for payment for the capacity "service". Reserve Capacity Refunds reflect the degree to which the service of providing capacity was not delivered.

The market settlement arrangements also include that:

- If the IMO purchases SRC Market Customers shoulder the costs as an unbudgeted expense proportionate to their share of the Shared Reserve Capacity Cost; and

- Under certain circumstances the IMO may also withhold security deposits from accredited new entrant capacity that does not meet the required performance measures specified in the rules. Withheld security is distributed to Market Customers in the month in which it is forfeited in accordance with the peak demand calculation used to determine Market Customer obligations – viz. the IRCR

The current arrangements results in the following issues:

### *7.2 Refund Distribution Issues*

1. Market Customers are unable to budget for their share of the distribution of refund payments due to the volatility around when Reserve Capacity Refund events, such as forced outages, occur.

2. Refunds are distributed to Market Customers regardless of any bilateral contracts for capacity that are in place. This presumes that the capacity payment is factored into the agreed bilateral contract price between Market Customers and accurately reflected in payments to Market Generators. Therefore any risk associated with contract prices not reflecting the prevailing capacity price (appropriately) will be borne by the contracting parties in accordance with the contract.

- For example: if a Market Generator accepts a contracted fixed price but the Reserve Capacity Price rises and Market Customer receives refunds at a higher rate than it is paying the Generator, then Market Generator is "leaving money on the table" as the market is valuing capacity higher than it is being paid: and vice versa.

***Security deposit issues***

1. Security deposits held by the IMO until such a time that the SRC risk associated with the respective facility ceases to exist. They are then allocated to Market Customers in the same trading month assuming where there was no requirement to fund SRC. The security deposits are then distributed on the basis of the Market Participants contribution to the Shared Reserve Capacity Cost. This is consistent with the basis for Market Customers obligation to fund capacity.

***SRC Related Issues***

1. In the event that an SRC event arises and funding is required, Market Customers are exposed to uncertain and lumpy cash flow requirements. This is unhelpful for budgeting and management of tariff settings for Market Customers where there can be multiple lagging cash flow effects around recouping the costs of any unbudgeted SRC payments.

2. The collection of Reserve Capacity Refunds and distribution to Market Customers may not align with times where an SRC event occurs and payment for the service is required and this misalignment may be seen as my lead to windfall gains or losses if new participants enter the market or others leave.

### 7.3 Opportunity for refinement

This section discusses a number of options for refinement in the light of the preceding observations within the broad design of the Reserve Capacity Mechanism and the concept of Reserve Capacity Refunds including:

- Aligning the methodologies to allocate Capacity Refunds and the allocation for withheld security deposits. There is also scope to look to adjust the timelines around the determination of the IRCR at a later date. Currently the IRCR is calculated using data from three months previous. This lagging effect could potentially be improved to exhibit only a one month lag.

- Creation of a fund to be held by the IMO and used to purchase SRC to remove the lumpiness in the payment required to the Market.

### 7.4 Mechanisms considered

Several mechanisms have been considered to address the issues listed above.

***Creation of a Market SRC fund to be held by the IMO and used for funding the procurement of SRC.***

Several approaches and methodologies could be employed to create a Market SRC Fund to meet at least some of the costs of any SRC procured by the IMO and thus reduce the size of calls to fund SRC.

- Approach 1 – Single SRC Fund (Dynamic Refund Distribution)

    - This would involve the creation of an on-going Market SRC Fund. The Fund would be empty at its creation and have a maximum level which would be set by the Market Rules.

    - The fund would initially be topped up by directing refunds that are currently distributed to Market Customers on a monthly basis. This would continue until the Fund reached the required level probably over a number of months;

    - Once the Fund reached the maximum level, the IMO would cease allocating refunds to the fund.

    - In the event that the IMO is required to procure SRC, the Fund would provide the initial funds with which to pay for the SRC.

    - If the Fund is partially used or depleted, then the IMO would allocate refunds to the Fund until it reaches the maximum level.

    While this approach will reduce the probability and risk of a call for funds to meet an SRC purchase there will be an unavoidable misalignment of the obligation to pay for the SRC at the time it is required and contributions to the Fund at an earlier time. For example a new entrant Market Customer could reap the benefits of the SRC fund but not directly contribute to it.

    However, this approach also means refunds will continue as now once the Fund is at its maximum level.

- Approach 2 – Cyclic Market SRC Fund

    - This approach also involves the creation of a single fund which would endure over multiple capacity years but be notionally emptied each year.

    - This fund would be empty at its creation and have a maximum level which would be set by the Market Rules.

    - The fund would initially be topped up by allocating refunds that are currently distributed to Market Customers on a monthly basis. This would continue until the fund reached the required maximum level.

    - Once the fund reached a maximum level, the IMO would notionally return the contributions to the Market Customers that contributed to it while at the same time requiring contributions to refill the fund. Continuing Market Customers with the same level of peak demand would face equal and opposite refunds and contributions. Only Market Customers with changing peak requirements would see any difference.

- If the need for SRC arises, then the will IMO utilise the fund to acquire SRC and procure any additional monies to cover any shortfall.

- Similarly if SRC was required refunds to existing Market Customers would be directed to refilling the fund in the first instance

This approach brings the allocation of obligations to fund SRC and entitlement to refunds closer but does not fully align the provision of the capacity "service" the obligation to pay for the capacity as those Market Customers who will be obligated to pay for the capacity service for any given year. This is also the case where those Market Customers who enter the Market reap the benefits of the SRC fund where they had not contributed to the creation of the fund.

While Approach two is potentially more equitable than Approach 1, there are potential practical issues with the implementation that make it the less attractive option. The cyclic fund may have unwanted settlement effects as refunds that are held in the fund would remain there for a period of 12 months (before they leave the cyclic fund). Their release would most likely coincide with the third settlement adjustment for a trading month. This may result in greater transfers of monies at this third adjustment period with no ability for re-course if implemented under the existing settlement arrangements. As such, settlement modifications would need to be made to accommodate this approach.

In each of the approaches refunds received by the IMO would in the first instance be used to build the SRC fund up to its maximum level (SRC Fund Cap). There seems no practical alternative to setting a maximum size of any SRC fund that is established and then allocating refunds over and above this amount to Market Participants. As Market Customers either directly or indirectly (though bilateral contracts) pay the entire capacity price it is appropriate to distribute "surplus" refunds to Market Customers (and inappropriate to allocate to other parties).

Each of the approaches for an SRC fund, however, would reduce the potential for lumpy calls for additional funds in the event SRC is purchased. Note however that once the fund is at its maximum level capacity refunds received by the IMO would be returned to Market Customers, albeit possibly using a different methodology to that used at present.

### 7.5 Proposed amendments

On balance the following amendments are recommended in relation to the application of funds received by the IMO as capacity refunds:

1. Create a SRC Fund with a cap equal to the SRC Fund Cap ( level to be decided – for example 50MW * Maximum Reserve Capacity Price);

2. Apply refunds received in a month to the SRC fund until the balance in the fund reaches SRC Fund Cap;

3. Interest received by the IMO in respect of the SRC fund to be added to the fund until the balance in the fund reaches SRC Fund Cap;

This package of amendments will reduce the risk and size of calls for funds to pay for SRC. It will also align the refunds more closely with the obligation to pay for capacity and hence be more cost reflective and thus more accurately reward demand side management initiatives by Market Customers. The IMO proposes that Approach 1 be used as it yields the desired outcomes, while avoiding the complication of the Cyclic Market SRC Fund in used Approach 2.

Alternatives to account for capacity obligations and refunds on a year by year basis including clearing the fund each year and utilising more complicated smoothing of refund streams have not been proposed. This is a judgement call based on the increased complexity for relatively little gain and a presumption that beyond the reduction in risk and size of calls on Market Customers to fund SRC purchases, participants should be responsible for (and prefer to) manage volatility of revenues. It is, however, clearly a matter for participants to debate.

## 8 RECOMMENDATION

That IMO recommends that the RDIWG:

- **Discuss** amendment of the capacity refund regime and endorse dynamically calculated refund factor based on actual reserve and a series of breakpoints as described above in section 5.45.1;

- **Discuss** removal of Net STEM shortfall as the basis for imposing refunds subject to its replacement with “Operational Test” (described in section 7.5) as a basis for refunds;

- **Discuss** the creation of a SRC Fund and endorse the allocation of refunds to that fund as described in section 7.4; and

- **Discuss** the allocation of refunds to Market Customers (after accounting for allocation to the proposed SRC Fund), interest on the SRC Fund and withheld security deposits on the basis of peak demand obligations using the principles for allocation of withheld security deposits within the current Market Rules.