Wholesale Electricity Market
Pre Market Rule Change Discussion Paper

Submitted by

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Change Proposal title:	Capacity Refund Mechanism – New Generators
Market Rule(s) affected:	4.26

Introduction

This Pre Market Rule Change Discussion Paper can be posted, faxed or emailed to:

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The discussion paper should explain how it will enable the Market Rules to better contribute to the achievement of the wholesale electricity market objectives. The objectives of the market are:

(a) to promote the economically efficient, safe and reliable production and supply of electricity and electricity related services in the South West interconnected system;
(b) to encourage competition among generators and retailers in the South West interconnected system, including by facilitating efficient entry of new competitors;
(c) to avoid discrimination in that market against particular energy options and technologies, including sustainable energy options and technologies such as those that make use of renewable resources or that reduce overall greenhouse gas emissions;
(d) to minimise the long-term cost of electricity supplied to customers from the South West interconnected system; and
(e) to encourage the taking of measures to manage the amount of electricity used and when it is used.

Details of the proposed Market Rule Change

1) Describe the concern with the existing Market Rules that is to be addressed by the proposed Market Rule change:

Overview

Section 4.26 of the Market Rules deals with the calculation of capacity refunds applied to Participants that do not meet their Reserve Capacity Obligations. The intent of this section is to provide an appropriate incentive to Participants to ensure they are able to meet their capacity obligations; or to ensure that their capacity is available at times when it is most required. The Refund Table (as part of the overall capacity systems itself) attempts to codify in one application a catch-all for all types of capacity and scenarios. Importantly, the refund table makes no distinction between existing generators and new entrant generators. New entrant generators have a very different risk profile to existing generators.

In 2007, a Reserve Capacity Refund Mechanism Working Group (the Working Group) was constituted to assess the drivers of the Reserve Capacity Refund Mechanism and to develop a more permanent solution to the Refund Table. The Working Group consisted of:

- IMO;
- Systems Management;
- Alinta;
- Verve;
- Synergy;
- Premier Power;
- TransAlta; and
- Perth Energy.

At this time, there were three major new entrant generation construction projects underway; Alinta's Wagerup OCGT (near completion); NewGen's Kwinana CCGT; and Griffin's Bluewaters Unit 1 coal fired power station. Neither NewGen nor Griffin, both constructing new capital intensive generation plant, were included on the working group. NewGen and Griffin were also not represented on the MAC at this time. Griffin believes that adequate consideration was not given to new entrant generators when developing the current Refund Table. It has become apparent that new entrant generators face excessive risks that lead to outcomes that are contrary to the Market Objectives.

Aligning the Refund Table with the intent of Section 4.26

Griffin believes that this clause in its present form, which has been changed several times in the past, does not strike an appropriate balance between being an efficient incentive and a being a punitive penalty, especially for the specific subgroup of Facilities that are new entrant generators. As an efficient incentive, capacity refunds are a useful mechanism to encourage Participants to manage their generation plant in a manner which optimises availability during times of peak demand. When the balance is skewed toward being a punitive measure, its usefulness as an incentive is diminished (i.e. a Participant will reach a point where additional costs will not impact its behaviour as all reasonable measures would have been adopted at a lower cost threshold. In fact a punitive penalty will reduce a participants financial ability to respond); and the inefficient costs to the market associated with the penalty increase (i.e. generators internalise the risk of activating the penalty, which is passed through to consumers as higher wholesale costs). Put simply, the market experiences higher costs for little or no benefit to reliability. This is clearly inefficient.

Griffin believes that the current form of the Rules is excessively punitive. This comes about due to the removal of the concept of seasonal caps. Seasonal caps protect generators that are unable to meet their Reserve Capacity Obligations from refunding their entire annual capacity payment stream in what can potentially be a very short time frame. And since there is little incentive to maintain availability once the maximum refund limit has been reached (at least with peaking facilities), then system reliability may be compromised in the later seasons.

Griffin also believes that the current alignment between incentive and penalty is inconsistent with the original intent of the Rules (and hence with the market objectives) when applied to new entrant generators. New generation plant is characterised by a very different risk profile than that of existing plant. New entrant plant is susceptible to one-off construction risk where the time frame for completing commissioning can blow out for extended periods. This is especially so with generation types characterised by higher and more complex capital requirements with longer less controllable lead times[1]. Construction delay is often out of the control of Participants (and increasing penalties to generators still under construction actually reduces the financial capacity of the Proponent to expedite the construction process). With the Market Rules not recognising this issue (or the concept of Force Majeure[2]), it can be expected that future new generation costs will include provisions for potential penalties. Griffin believes that the inclusion of seasonal caps is important to prevent unnecessary and inefficient potential punitive penalties to new entrant generators.

This is not inconsistent with previous interpretations of the Rules. The Refund Table in Section 4.26 in the original version of the Rules contained a provision for daily and seasonal caps. The next incarnation of this table, from the EIRU, modified these caps (before reverting to the original version on review by the Office of Energy). The remit for the IMO to again review this issue came with the specific direction from the Office of Energy that:

> *"The Market Advisory Committee will be asked to consult with industry and to develop a solution to the issues with Rules that relate to Capacity Cost Refunds that were identified by the IMO in developing its IT Systems, and to ensure that these Rules achieve their intent* ***without being unduly harsh on any single Market Participant or group of Market Participants****."* – OOE Rule change report

Griffin believes, on the basis of the arguments above, that this proviso has not been met. The current rule discriminates against and presents greater potential risks to new entrant plant over existing plant – and especially so over new entrant plant with high fixed capital cost and construction requirements.

[1] The capacity refund mechanism; and the whole capacity market itself; has long been recognised as been a poor mechanism to deal effectively with differing types of capacity. In this instance, the difference between new entrant generators is stark. An aero-derivative OCGT can be constructed in around 6-9 months using a labour force of between 50 and 100, with much of the components arriving at site prefabricated elsewhere. A large coal fired power station can take between 3-4 years to construct, and require a labour force of over 600 at any one time. It is very obvious that these types of projects present different construction risk profiles, yet are dealt with using the same set of rules – a set of rules which is based on the dynamics of constructing an OCGT power station.

[2] The new entrant Participant is subject to the normal force majeure from contractors and suppliers but has no force majeure recourse under the market rules. This means legitimate construction delays cannot be cited as a reason for lateness. This increases the risk to new participants thereby restricting new entrants and adding to costs. Also, this provision may increase the leverage of construction labour and others, where in dispute with the baseload proponent, which may add to delays and increase costs.

Griffin also points out that the purpose of capacity credit refunds is to incentivise reliability and availability. While this may be effective for peaking generation, which has little other incentive to maintain availability, base load generators are less inclined to see these penalties as their main driver for availability. Base load generators are financed on their long term offtake agreements, or their ability to sell large quantities or energy into a liquid market. Capacity payments are inconsequential in that electricity sales, through bilateral contracts, comprise the Long Run Marginal Cost of producing electricity, or is a bundled price comprising the fixed capital cost and the variable operating cost. A far bigger incentive (and potential cost) to a base load generator is, if unavailable, the requirement for it to meet its substantive contracted energy obligations with the marginal price of energy being produced in the market. It can be readily assumed that this marginal unit of energy will cost considerably more to produce than the base load energy it is replacing. This means that allocating higher capacity refund penalties to base load generators, especially new entrant generators, is simply adding further risks and costs that do little, if anything, to incentivise reliability and which will ultimately be passed through to consumers.

Costs that discriminate against base load and mid merit generators do so at the expense of market efficiency. An efficient market is one that optimises the mix of generation types. Regulation that alters the incentive to invest in the optimal generation mix leads to a reduction in market efficiency. The current Capacity Mechanism under the Rules is strongly supportive of new simpler, lower cost peaking plant but does little to encourage new base load capacity.

Proposed amendments

Griffin supports the re-introduction of seasonal caps while maintaining the signals developed under the significant MAC sub-group review of the refund mechanism. In this way, the original balance between providing efficient incentives for availability (without being *unduly harsh* on specific Participants – especially new entrant generators); can coexist with the more appropriate interval-specific signals adopted by the MAC sub-group. The seasonal caps proposed are adapted from the caps used in the original Market Rules, where:

Season	**Cold**	**Intermediate**	**Hot**
Maximum Seasonal Rate ($ per maximum Trading Interval MW shortfall)	0.3 x Y	0.1 x Y	0.6 x Y

Where Y represents the annual maximum refund possible under the rules (which was not immediately apparent in the original drafting). In order to differentiate Y (as it currently applies in the Refund Table) we suggest that the annual maximum refund concept is denoted as A.

This equated to a cap of 30% of the annual maximum capacity refund applying to the cold season; a cap of 10% of the annual maximum capacity refund applying to the intermediate season; and a cap of 60% of the annual maximum capacity refund applying to the hot season. As the Hot season was split into a Hot and a Peak season by the MAC sub-group, we propose the following:

Season	**Cold**	**Intermediate**	**Hot**	**Peak**
Maximum Seasonal Rate ($ per maximum Trading Interval MW shortfall)	0.3 x A	0.1 x A	0.25 x A	0.35 x A

Adding seasonal caps (without the daily caps) has the effect of enforcing refunds up to a predetermined cap in each season. If the cap is reached, the refunds stop. Additional refunds incurred in subsequent seasons would be cumulative until the maximum refund limit is reached. This spreads out the time for which Participants must refund up to their maximum amount (if applicable) without inhibiting the interval-specific signals applied to shorter outages. Griffin believes that implementing this methodology should not pose significant issues to the IMO IT systems and monthly settlement processes.

Figure 1 below compares the proposed refund profile with the current refund profile for Participants that are unable to meet their capacity obligations for the whole year (i.e. the worst case scenario).

Figure 2 shows the average daily refunds (of a long-term outage) as a ratio of capacity payments. The daily refunds are weighted over peak and non peak intervals and differentiated by business and non-business days.

Figure 3 compares the proposed refund profile with the current refund profile for Participants that are unable to meet their capacity obligations for the Hot and Peak seasons only. This is when new entrant generators that have experienced delays are expected to begin their capacity obligations. For an existing generator that is on a long term outage from the start of the capacity year (01 October), there is a small surplus of payments to refunds (i.e. a net benefit) throughout the Intermediate season (see Figure 1 Oct-Dec). This is not available to new entrant generators. Figure 3 clearly shows that new entrant generators are immediately exposed to high penalties. Griffin suggests that the 'Proposed Refund Profile' (blue line):

- represents an efficient incentive regime;
- is consistent with the original intent of the Market Rules; and
- meets the Office of Energy caveat of not being unduly harsh on any single Market Participant or group of Market Participants.

The area between the 'Proposed Refund Profile' (blue line) and the 'Current Refund Profile' (orange line – and the area above the orange line) is an inefficient cost that will be passed through to consumers as higher long-term wholesale electricity prices.

Figure 1 Capacity refund profiles

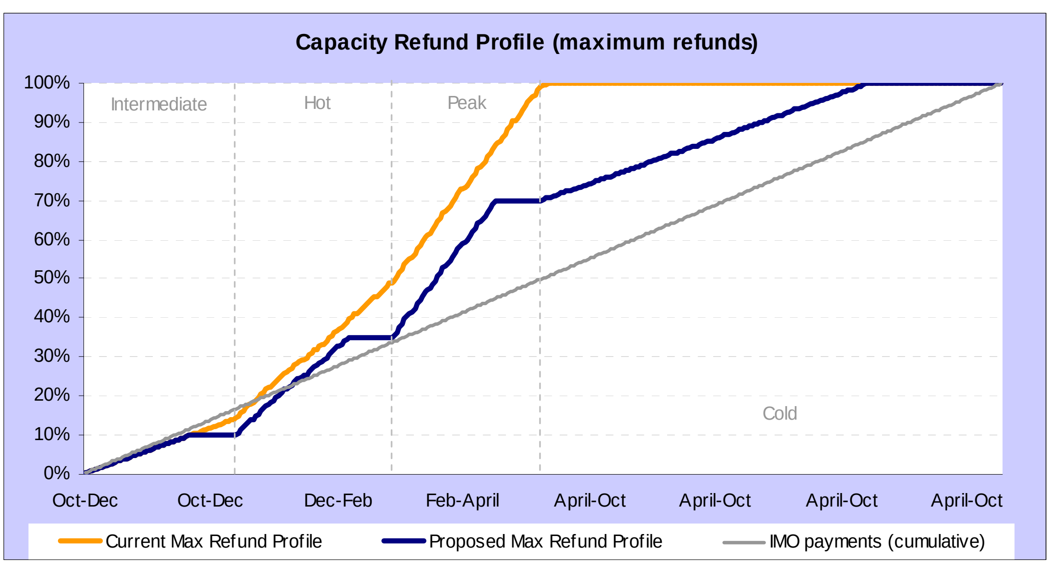


Figure 2 Average daily capacity refund ratios

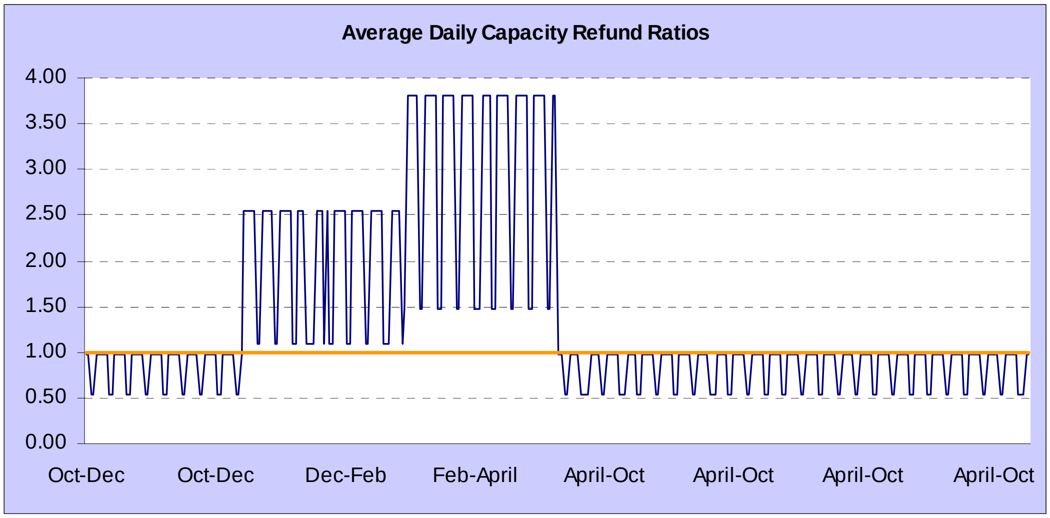
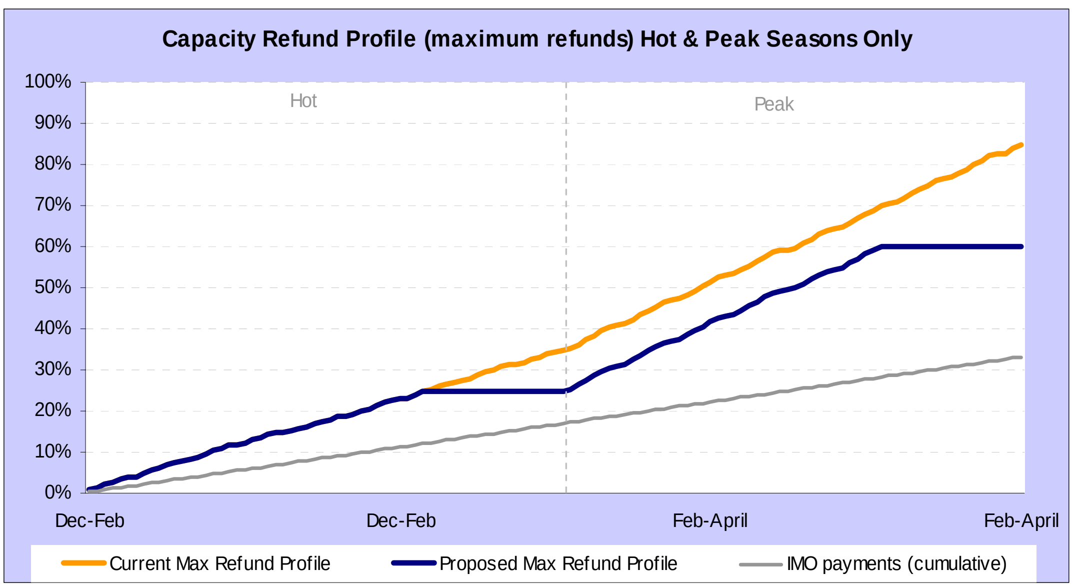


Figure 3 Hot and Peak season capacity refund profiles



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2) Explain the reason for the degree of urgency:

Griffin proposes that this change is processed using the Fast Track Rule Change Process on the basis that it satisfies the criteria in section 2.5.9(b) of the Rules.

Section 2.5.9 states:

The IMO may subject a Rule Change Proposal to the Fast Track Rule Change Process if, in its opinion, the Rule Change Proposal:

(a) is of a minor or procedural nature; or

(b) is required to correct a manifest error; or

(c) is urgently required and is essential for the safe, effective and reliable operation of the market or the SWIS.

This rule change proposal deals with a section of the Rules which clearly discriminates against a specific group of Market Participants – that of new entrant generators. Griffin believes that the previous change to the Refund Table, by not adequately addressing the impacts in new entrant generators, represents an obvious error that requires correction – 2.5.9(b). It can also be maintained that, given the potential costs involved to Market Participants; the timing of when these costs may be incurred, and the (lack of) effectiveness of the price signals offered by the current rules, then this rule change is urgently required in order to maintain an effective market – 2.5.9 (c).

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3) Provide any proposed specific changes to particular Rules (for clarity, please use the current wording of the Rules and place a ~~strikethrough~~ where words are deleted and <u>underline</u> words added)

REFUND TABLE

Dates	**1 April to 1 October**	**1 October to 1 December**	**1 December to 1 February**	**1 February to 1 April**
Business Days Off- Peak Trading Interval Rate ($ per MW shortfall per Trading Interval)	0.25 x Y	0.25 x Y	0.5 x Y	0.75 x Y
Business Days Peak Trading Interval Rate ($ per MW shortfall per Trading Interval)	1.5 x Y	1.5 x Y	4 x Y	6 x Y
Non-Business Days Off-Peak Trading Interval Rate ($ per MW shortfall per Trading Interval)	0.25 x Y	0.25 x Y	0.5 x Y	0.75 x Y
Non-Business Days Peak Trading Interval Rate ($ per MW shortfall per Trading Interval)	0.75 x Y	0.75 x Y	1.5 x Y	2 x Y
<u>Maximum Seasonal Cap ($ per maximum possible Trading Interval MW shortfall per season multiplied by the expected annual Capacity Credit payments)</u>	<u>0.30 x A</u>	<u>0.10 x A</u>	<u>0.25 x A</u>	<u>0.35 x A</u>

<table>
<tr><td>Maximum Participant Refund</td><td>The total value of the Capacity Credit payments paid or to be paid under these Market Rules to the relevant Market Participant for the 12 Trading Months commencing at the start of the Trading Day of the previous 1 October assuming the IMO acquires all of the Capacity Credits held by the Market Participant and the cost of each Capacity Credit so acquired is determined in accordance with clause 4.28.2(b), (c) and (d) (as applicable).</td></tr>
<tr><td colspan="2">Where:

For an Intermittent Facility that has been commissioned: Y equals 0; and A equals 0

For all other facilities, including Intermittent Facilities that have not been commissioned: Y equals the greater of the Reserve Capacity Price and 85% of the Maximum Reserve Capacity Price for the relevant Reserve Capacity Auction, expressed as a $ per MW per Trading Interval figure. This is determined by dividing the Monthly Reserve Capacity Price by the number of Trading Intervals in the relevant month; and A equals the total value of the Capacity Credit payments associated with the relevant Facility paid or to be paid under these Market Rules to the relevant Market Participant for the 12 Trading Months commencing at the start of the Trading Day of the most recent 1 October, assuming the IMO acquires all of the Capacity Credits associated with that Facility and the cost of each Capacity Credit so acquired is determined in accordance with clause 4.28.2(b), (c) and (d) (as applicable).</td></tr>
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4) Describe how the proposed Market Rule change would allow the Market Rules to better address the Wholesale Market Objectives:

Griffin believes that its proposed rule change proposal better achieves market objectives (a); (c) and (d); and has a neutral affect on objectives (b) and (e).

(a) to promote the economically efficient, safe and reliable production and supply of electricity and electricity related services in the South West interconnected system;

To promote a reliable supply of electricity, appropriate incentives must be applied that encourages generators to be available at times of peak demand. To ensure that these incentives are also economically efficient, a correct balance must be achieved between financial incentive and punitive cost. Punitive costs that do not improve reliability and are ultimately passed through to consumers is clearly inefficient. The proposed rule change seeks to refine this balance and return it to closer to the original intent of the rules.

Further, inefficient financial penalties for new entrant generators that have not yet commissioned plant may incentivise work practices that lead to less stringent safety standards. The safe production of electricity in the SWIS is a very serious concern and must certainly extend to the construction of new entrant generation facilities.

(c) to avoid discrimination in that market against particular energy options and technologies, including sustainable energy options and technologies such as those that make use of renewable resources or that reduce overall greenhouse gas emissions;

Griffin contends that the rule, as it currently stands, discriminates against the differing risk profiles of new entrant generators over incumbent generators as well as [and especially] against new entrant generators with high fixed capital costs. The proposed rule change offsets some of these discriminatory effects.

(d) to minimise the long-term cost of electricity supplied to customers from the South West interconnected system;

Inefficient costs, as outlined in point (a), are those imposts on Participants that do not return a net value to the market. New entrant base load and mid merit generators that rely on; and are incentivised to be available by; their energy sales obligations are poorly incentivesd (if at all) by higher capacity refunds. These costs are ultimately passed on consumers.

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5) Provide any identifiable costs and benefits of the change:

The long term benefit of the rule change is the reduction of inefficient costs in the market leading to a lower long term cost of producing electricity.

Direct costs are in the form of IMO systems and procedural changes. Griffin does not believe these costs will be significant compared to the long term benefits.

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