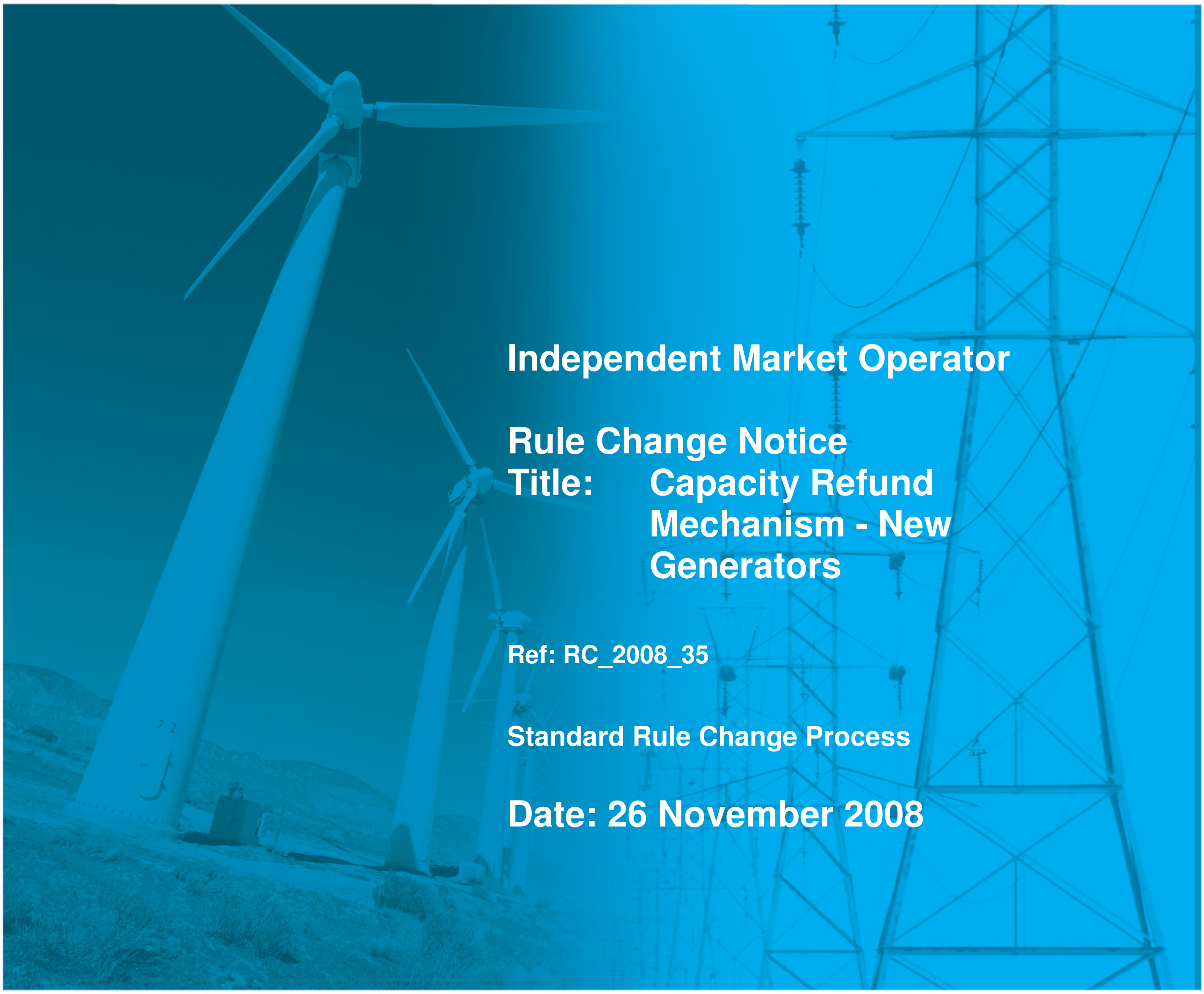

Independent Market Operator

Rule Change Notice

Title: Capacity Refund Mechanism - New Generators

Ref: RC_2008_35

Standard Rule Change Process

Date: 26 November 2008

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1. THE RULE CHANGE PROPOSAL

1.1. The Submission

On 14 November 2008 Griffin Energy submitted a Rule Change Proposal regarding changes to clause 4.26 of the Wholesale Electricity Market Rules (Market Rules).

This Rule Change Notice is published according to Market Rule 2.5.7, which requires the IMO to publish a notice within 7 Business Days of receiving a Rule Change Proposal.

1.1.1 Submission details

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Urgency:	*High*
Change Proposal title:	Capacity Refund Mechanism – New Generators

1.2. Details of the Proposal

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. The details of these outcomes are set out elsewhere in this proposal.

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[1], 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. A rational 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 additional costs will reduce a participants financial ability to respond). This leads to an increase in inefficient costs to the market (i.e. generators internalise the risk of activating the penalty, which is passed through to consumers as higher wholesale costs[2]). Put simply, the market experiences higher costs for little or no benefit to reliability. This is clearly inefficient and contrary to the objectives of the electricity market.

This inefficiency is particularly apparent to new entrant generators. New entrant generators have a far greater likelihood of experiencing extended 'outages' in the form of construction delays, leading to the repayment of capacity refunds much more quickly during the Hot season (when the capacity obligations of new entrant generators begin). 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. Additionally, since there is little incentive to maintain availability once the maximum refund limit has been reached (with peaking facilities), then system reliability may be compromised in the later seasons.

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 for reasons beyond the control of the generator. This is especially so with generation types characterised by higher and more complex capital requirements with longer less controllable lead times[3]. This has the effect,

[1] Including, importantly, significant changes being made subsequent to Griffin relying upon the previous regime when negotiating and agreeing the damages regime applicable under its EPC contract for the construction of Bluewaters Unit 1 power station

[2] See Text Box 1

[3] The capacity refund mechanism; and the whole capacity market itself; is 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

contrary to the market objectives, of discriminating against particular energy options and technologies. 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[4]), it can be expected that new generation costs will include provisions for such potential significant penalties. Griffin believes that the re-introduction of seasonal caps is important to prevent unnecessary and inefficient potential penalties to new entrant generators.

This is not inconsistent with previous versions 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)[5]. 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 submits, on the basis of the arguments above, that this proviso requirement of the Rules 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.

Griffin also submits 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 off-take agreements, or their ability to sell large quantities of energy into a liquid market. Capacity payment revenue, or the arbitrary value placed on capacity under the mechanism which sets the Maximum Reserve Capacity Price, is not a consideration when setting prices through bilateral contracts. These prices comprise the Long Run Marginal Cost of producing electricity, or is a bundled

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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.

[4] 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.

[5] There have been interpretational discrepancies with the previous wording of the rules around capacity refunds. These have revolved around the use of the terms 'average' and 'maximum' refunds. Griffin points out that for new entrant generators, where the outage is due to construction delay, the total expected capacity of the facility is likely to be affected for all intervals, so the distinction between average and maximum becomes irrelevant. This highlights the excessive nature that capacity refunds designed to incentivise reliability can have on new entrant generators.

price, comprising the fixed capital cost and the variable operating cost. Capacity payments, based on the fixed capital costs of a liquid fired OCGT, bear no relevance to the fixed costs of a base load generator. Capacity payments merely form a 'settlements loop' where they are transferred from retailers to generators via the IMO (while capacity itself, as an arbitrary component of the bundled electricity and essentially an abstract financial instrument created and controlled by the IMO, is in return transferred to the retailer). A far bigger incentive (and potential cost) to a base load generator is the requirement for it to meet its (often) substantive contracted supply obligations using 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.

<u>Proposed amendments</u>

Griffin supports the re-introduction of seasonal caps while maintaining the price 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 represented the annual maximum refund possible under the rules[6]. In order to differentiate Y (as it currently applies in the Refund Table) we have suggested in our proposed amendment that the annual maximum refund concept is denoted as "A" (see below).

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:

[6] This was not immediately apparent in the original Market Rules.

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 and increases the timeframe for which Participants refund up to their maximum amount (i.e. the Maximum Applicable Refund – if applicable) without inhibiting the interval-specific signals applied to shorter duration 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 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. This is manifestly inconsistent with the market objectives.

Figure 1 Capacity refund profiles

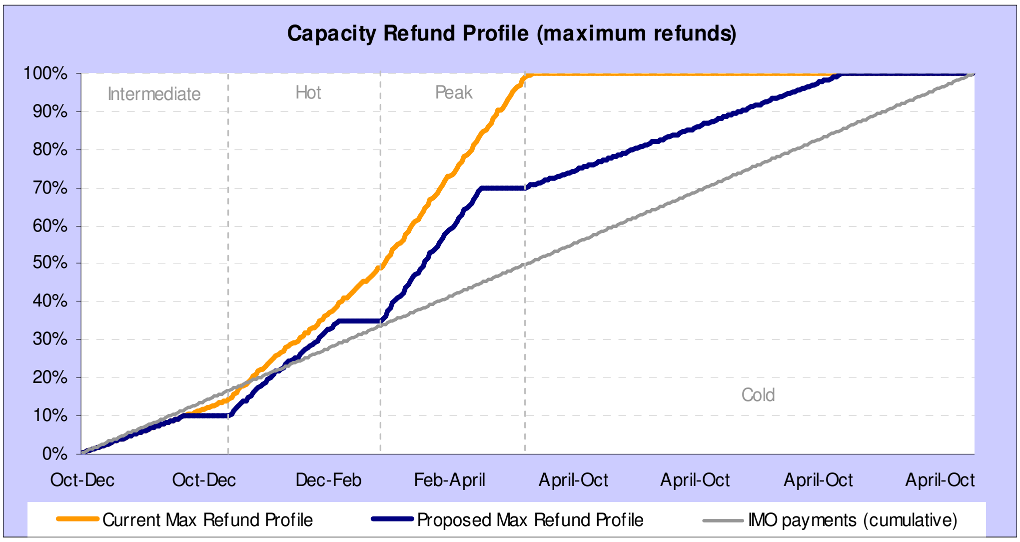


Figure 2 Average daily capacity refund ratios

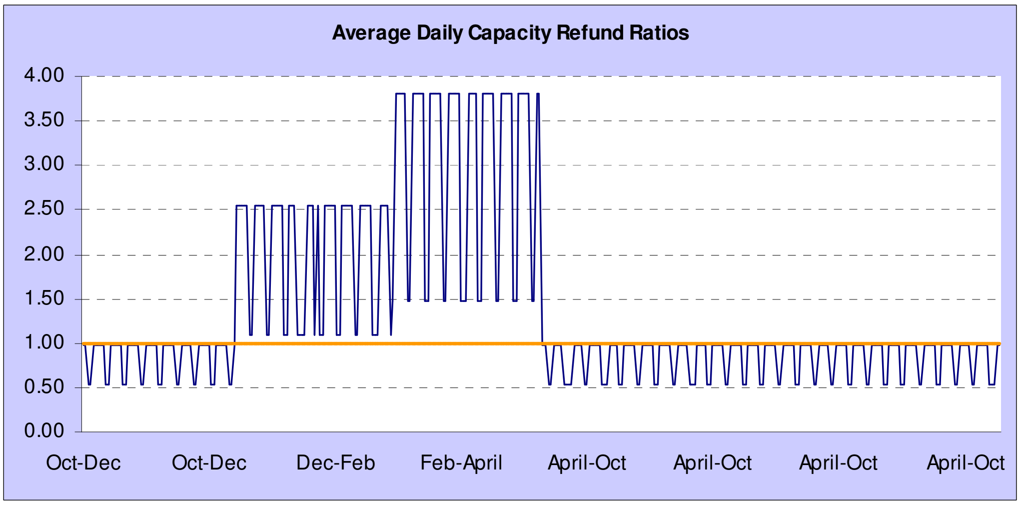
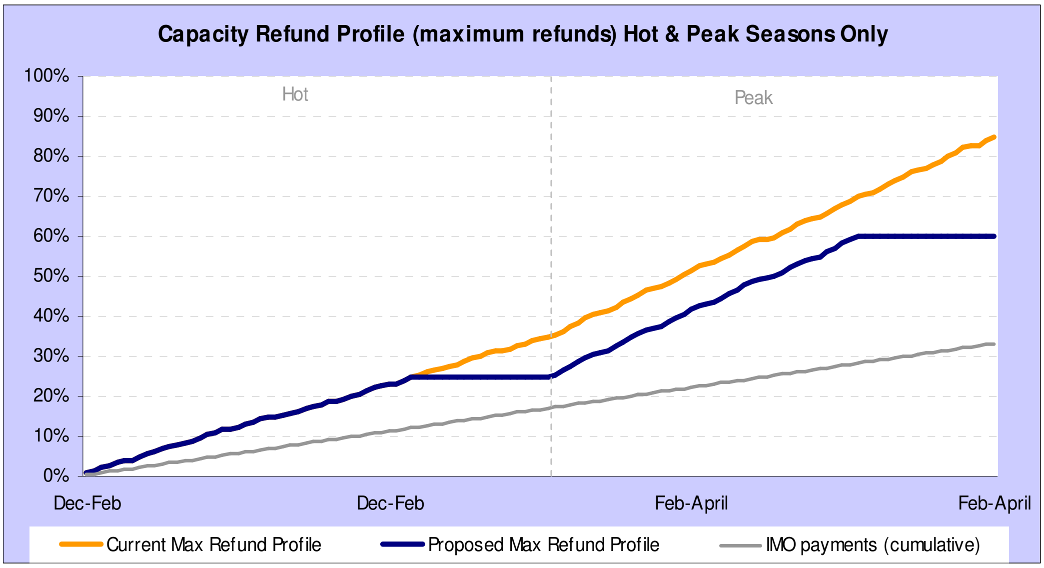


Figure 3 Hot and Peak season capacity refund profiles



Text Box 1

In a bilateral energy market, to finance the construction of an energy producing generator (rather than a reserve margin generator which relies on payments for making capacity available), a developer must be able to bilaterally contract the output of the facility on the basis of its Long Run Marginal Cost – comprising the energy and the capacity. How the output price is apportioned between these two amounts is arbitrary. Capacity payments in the WEM are based on the fixed costs of a liquid fuelled peaking facility. This does not bear any relevance to the fixed and variable costs of a base load facility. The capacity market simply creates a demand for an abstract financial instrument (capacity credits) that is met by the award of a right to generate capacity credits by the IMO to a generator. While the value of a generator's output is affected by whether it is granted this right, the ***quantum of this value*** to any generator which sells a product that is composed of more than capacity alone[7] is arbitrary and is simply required to complete a settlement loop. The generator effectively has two separate commitments for contracted availability. The first is to its off take counterparty for the delivery of the (real) output of the plant. The second is to the IMO to meet the requirement for the award of an (abstract) capacity credit. A new entrant generator is incentivised to meet its project delivery dates by its contractual off take obligations. ***The capacity refund mechanism, by refunding capacity credits at higher rate than being granted them, simply becomes an arbitrary financial penalty***[8] – or a cost additional to the cost of meeting the contracted commitments. If a new

[7] For a pure peaking plant (or one that provides capacity to meet only the marginal MWh of demand in the system), the LRMC of production is equivalent to the fixed capital cost. In this case, the price paid for capacity is important.

[8] The IMO describes capacity refund repayments as a 'refund' only and is careful not to use the term 'penalty'. If the repayments to the IMO were made at the same rate at which the capacity payments were made (or at a reduced rate), then the term refund (or partial refund) would be sensible. As the repayments are made at a rate that is higher

generator expects that it might incur additional costs for not delivering on time (where as a new entrant generator it is at its most vulnerable to construction risk and force majeure, which are largely non-controllable risks), it will 'manage this risk' by pricing the cost of these refunds into the project development as an additional contingency. This is a commercial reality of project development, where financiers protect their investments as a priority. The cost of financing the additional risk premium is a cost that is then borne by the market through higher wholesale electricity prices – whether the generator incurs the capacity penalties or not. While the generator, though poorly equipped to manage this risk, is probably still the best placed to do so, Griffin contends that the risk itself should not be there in the first place, as there is little additional return to the cost imposed in managing it.

The argument that: if the generator does not price in this cost, then others in the market (i.e. retailers) will price it in, is flawed. This is only applicable if the late delivery of a generator actually leads to higher market costs. Higher costs may be incurred through calling for supplementary reserve capacity (SRC) and through replacing the expected generation with higher cost generation in the market. Griffin does not believe there is sufficient evidence to suggest that forcing a generator to price in the potential refund penalty cost of each project development (regardless of whether it incurs penalties) – and pass that cost on through higher wholesale pricing, is more efficient (cost effective) than incurring costs relating to SRC on an infrequent basis[9]. The second potential market cost impost; that of higher priced electricity for the marginal unit not produced by the generator, will primarily be ***borne by the generator in a bilateral market*** (through its supply obligations) and is actually their main driver for ensuring timely delivery.

1.3. The Proposal and the Wholesale Market Objectives

Griffin submits 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;

It is Griffin's view that 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 an inefficient cost. Costs that do not improve reliability and are ultimately passed through to consumers is clearly economically inefficient. The proposed rule change seeks to address the application of inefficient costs, especially to new entrant generators which are more exposed to these costs and less likely to [*be able to*] respond to them with improvements in reliability.

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than payments; and, importantly, for a generator that has contracted off take obligations to transfer capacity rights, as the difference between payments an repayments is unable to be recouped once the plant is available again, then the capacity repayments made above the level of capacity payments received can only logically be viewed as a penalty.

[9] The fact that SRC is potentially uncapped would appear a flaw in an otherwise price regulated market

Further, Griffin contends that inefficient financial penalties for new entrant generators that have not yet commissioned plant may potentially lead to work practices that result in less stringent safety and reliability standards. The safe and reliable 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 submits 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 and long lead time projects. 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;

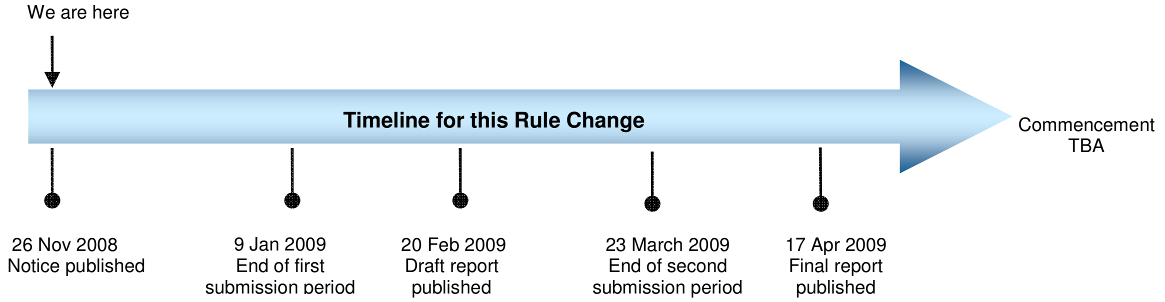
Griffin defines inefficient costs, as outlined in point (a), as being those imposts on Participants that do not return a net value to the market. New entrant base load and mid merit generators that rely on; and are incentivised to be available by; their energy sales obligations are poorly incentivised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

2. WHETHER THE PROPOSAL WILL BE PROGRESSED FURTHER

The IMO has decided to proceed with this proposal on the basis that the IMO's preliminary assessment indicated that the proposal is consistent with the Wholesale Market Objectives.

The IMO has decided to process this Rule Change Proposal using the Standard Rule Change Process, described in section 2.7 of the Market Rules.

The projected timelines for processing this proposal are:



CALL FOR SUBMISSIONS

The IMO is seeking submissions regarding this proposal. The submission period is six weeks from the publication date of this notice. Submissions must be delivered to the IMO by close of business on **Friday 9 January 2009.**

The IMO prefers to receive submissions by email to **marketadmin@imowa.com.au** using the submission form available on the IMO website:
http://www.imowa.com.au/10_5_1_MarketRulesChangeSummary.html

Submissions may also be sent to the IMO by fax or post, addressed to:

Independent Market Operator
Attn: Manager Market Administration
PO Box 7096
Cloisters Square, Perth, WA 6850

Fax: (08) 9254 4399

4. PROPOSED AMENDING RULES

The IMO proposes the following amendments to the Market Rules (~~deleted words~~, added words):

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
Maximum Seasonal Cap ($ per maximum possible Trading Interval MW shortfall per season multiplied by the expected annual Capacity Credit payments)	0.30 x A	0.10 x A	0.25 x A	0.35 x A
Maximum Participant Refund	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).			

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).

5. ABOUT RULE CHANGE PROPOSALS

Market Rule 2.5.1 of the Wholesale Electricity Market Rules (Market Rules) provides that any person (including the Independent Market Operator) may make a Rule Change Proposal by completing a Rule Change Proposal Form and submit this to the Independent Market Operator (IMO).

The IMO will assess the proposal and, within 5 Business Days of receiving the proposal form, will notify the proponent whether the proposal will be progressed further.

In order for the proposal to be progressed the change proposal must explain how it will enable the Market Rules to better contribute to the achievement of the Wholesale Market Objectives. The market objectives 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.

A Rule Change Proposal can be processed using a Standard Rule Change Process or a Fast Track Rule Change Process. The standard process involves a combined 10 weeks public submission period, while the fast track process involves the IMO consulting with Rule Participants who either advise the IMO that they wish to be consulted or the IMO considers have an interest in the change.