RULE CHANGE NOTICE

LIMITS TO EARLY ENTRY CAPACITY PAYMENTS

(RC_2012_10)

This notice is given under clause 2.5.7 of the Market Rules.

Date Submitted: 14 June 2012

Submitter: Will Bargmann, Synergy

THE PROPOSAL

The Reserve Capacity Mechanism requires credited capacity to be available from the first day of the Capacity Year (1 October). To ensure that new capacity arrives prior to this date the window of entry for new capacity was brought forward via the Rule Change Proposal: Changing the Window of Entry into the Reserve Capacity Mechanism (RC_2009_11) from between 1 June -1 October, previously 1 August -30 November. Synergy states that in making the changes under RC_2009_11 the market recognised that conventional generation, as opposed to Demand Side Programmes (DSPs), is prone to being unreliable for several months after commissioning. The change of timing for entering the market, which provides Market Participants with access to an earlier stream of Capacity Credit payment, was to reduce the risk that generation capability would be late entering the market and the IMO would be required to call a Supplementary Reserve Capacity auction.

Synergy submits that there is a technical difference between generation capacity and other forms of capacity such as DSPs and that this difference serves as a basis on which to differentiate access to early capacity payments. That is, access to the early capacity payments should only be available to conventional generators and is not intended for forms of capacity which do not suffer extended periods of post commissioning remedial work which would materially affect their reliability.

Synergy consequently proposes amendments to clause 4.1.26 of the Market Rules to limit early entry payments between 1 June and 1 October to Scheduled Generators and Non-Scheduled Generators only. Other capacity types, such as DSPs, would be only entitled to capacity payments from 1 October when their Reserve Capacity Obligations begin to apply.

Appendix 1 contains the Rule Change Proposal and gives complete information about:

- the proposed amendments to the Market Rules;
- relevant references to clauses of the Market Rules and any proposed specific amendments to those clauses; and

- the submitter's description of how the proposed amendments would allow the Market Rules to better address the Wholesale Market Objectives.

DECISION TO PROGRESS THE RULE CHANGE

The IMO has decided to progress the Rule Change Proposal to allow interested parties an opportunity to provide submissions as part of the rule change process.

Further, after two years of providing access to early entry capacity payments for new entrants[1] the IMO considers it is now appropriate to reconsider the ongoing need for maintaining this incentive structure. RC_2009_11 was implemented during a time of capacity shortage in the market, when the benefit of encouraging the timely delivery of capacity was considered likely to exceed any potential costs to the market. It is appropriate, now that better cost information is available, to review this assessment, particularly given the other incentives that exist or are under consideration in the market to encourage the timely delivery of reliable capacity.[2].

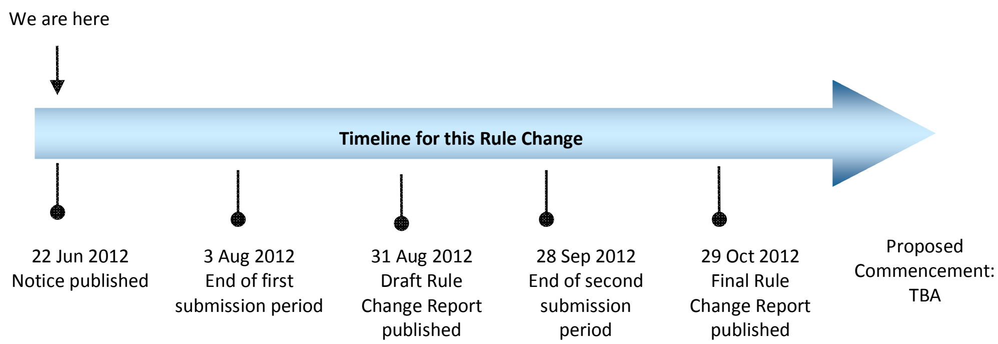
On this basis the IMO seeks the views of interested parties on extending the concept presented in the proposal to remove early entry capacity payments in their entirety - that is for both generation and demand side options.

The IMO considers that removing the concept of early entry capacity payments in its entirety would represent an equitable treatment of the energy options and ensure that a non-discriminatory approach is adopted (consistent with Wholesale Market Objective (c)). The IMO also notes that this would be consistent with the current direction of the Reserve Capacity Mechanism Working Group (RCMWG) in harmonizing the treatment of demand side options with generation in the market.

TIMELINE

The projected timelines for processing this proposal are:

[1] The Amending Rules for RC_2009_11 commenced 1 December 2009.
[2] The IMO notes the work of the RCMWG in considering options for implementing a dynamic capacity refund mechanism as part of its ongoing work stream.



CALL FOR SUBMISSIONS

The IMO is seeking submissions regarding this proposal. The submission period is 30 Business Days from the publication date of this Rule Change Notice. Submissions must be delivered to the IMO by **5:00pm** on **Friday, 3 August 2012**.

The IMO prefers to receive submissions by email to market.development@imowa.com.au using the submission form available on the IMO website: http://www.imowa.com.au/rule-changes.

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

Independent Market Operator
Attn: Group Manager, Market Development
PO Box 7096
Cloisters Square, Perth, WA 6850
Fax: (08) 9254 4399

Wholesale Electricity Market
Rule Change Proposal Form

Change Proposal No: *RC_2012_10*
Received date: *14 June 2012*

Change requested by:

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	14 June 2012
Urgency:	1 - High
Change Proposal title:	Limits to early entry capacity payments
Market Rule(s) affected:	4.1.26

Introduction

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

This Change Proposal can be posted, faxed or emailed to:

Independent Market Operator
Attn: Manager Market Development and System Capacity
PO Box 7096
Cloisters Square, Perth, WA 6850
Fax: (08) 9254 4339
Email: market.development@imowa.com.au

The Independent Market Operator will assess the proposal and, within 5 Business Days of receiving this Rule Change Proposal form, will notify you whether the Rule Change Proposal will be further progressed.

In order for the proposal to be progressed, all fields below must be completed and the change proposal must 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

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

Overview

This Rule Change Proposal proposes amendments to clause 4.1.26 of the Market Rules.

The amendments would limit early payment for Reserve Capacity, which can commence on 1 June prior to the commencement of the Capacity Year, to Scheduled Generators and Non-scheduled Generators. In the case of other types of Facilities, Reserve Capacity Obligations would apply from 1 October.

History

By way of background, Synergy notes that Alinta presented a similar pre-rule change proposal in 2010. Alinta subsequently withdrew that pre-rule change proposal, as a result of concerns raised that the proposal would not be consistent with market objective (c), because it would not avoid discrimination.

Synergy has recently reviewed the concerns regarding discrimination. In Synergy's view, those concerns should be revisited, particularly in light of the fundamental differences in the characteristics of different types of energy options and technologies.

Synergy has obtained legal advice on the interpretation and practical application of market objective (c).

In summary:

(a) The concept of “discrimination” in market objective (c) is not defined.

(b) Dictionary definitions generally refer to “discriminate” or “discrimination” as distinguishing one thing from another, or expressing a preference for one thing over another.

(c) The law recognises a distinction between direct and indirect discrimination. By analogy, direct discrimination involves treating a Facility or a technology in a different manner (in a less favourable sense) from the manner in which another Facility or technology would be treated in comparable circumstances. Indirect discrimination occurs where two Facilities or technologies appear to be treated equally, but the impact of such “equal” treatment is that one Facility is in fact treated less favourably than the other.

(d) The concept of “discrimination” used in market objective (c) is interpreted by reference to, and is generally complimentary with, the other market objectives and, in a broader sense, the operation of the Market Rules.

On the basis of this legal advice, Synergy considers that it is permissible for the Market Rules to treat Scheduled Generators and Non-Scheduled Generators differently from other types of Facilities, where that different treatment is based on fundamental differences in the characteristics of those Facilities. This interpretation is more consistent with the market objectives and the operation of the market rules.

Further, the legal advice concluded (based upon indirect discrimination) there is a good argument that the Rule Change Proposal would address apparent existing discrimination in the WEM, in favour of DSPs, and against Scheduled Generators and Non-Scheduled Generators. Synergy has seen this manifest itself in Market Generators expressing their displeasure at the payments made to DSPs, because they effectively treat market generators and DSPs as having the same risk profile. The early payment of capacity to DSPs can be such an example.

Synergy’s intention

Synergy is submitting this proposal as a Rule Change Proposal because the relevant issues have previously been discussed by the MAC.

Background

The Reserve Capacity Mechanism requires credited capacity to be available from the first day of the Capacity Year but recognises that different types of capacity need different preparations before this can happen. The initial design of the WEM allowed for capacity to arrive between August and November (referred to in this Rule Change Proposal as the Reserve Capacity Window) to reduce the potential for post-commissioning reliability problems to continue into December, the first month of the summer peak demand period.

The timing of the reserve capacity window has been brought forward via rule change 2009_11 which allowed new capacity to arrive from 1 June 2012. This rule change was presented and finally endorsed to allow an extra period of post-commissioning, before the start of the capacity year, for new generators to shake-down (remove) technical and operational issues inevitably present after commissioning.

In making this change, the market recognised that conventional generation, as opposed to DSPs, is prone to being unreliable for several months after commissioning as issues not discoverable in the lead up to and during commissioning become evident and are rectified. The change of timing and earlier access to capacity credit payments was based upon a market consideration that an early payment was preferred to the possibility of the risk of a new generator arriving late missing part or all of the its first summer. At the time RC_2009_11 was being considered, the market was concerned that the event of a reduced generation capability due to expected late arrival could lead to the IMO calling a supplementary reserve capacity (SRC) auction. Such an auction had been called the previous summer due to the expected late arrival of Bluewaters, and so the possibility of an SRC appeared more of a possibility than perhaps the case today.

This Rule Change Proposal submits that there is a technical difference between Scheduled/Non-Scheduled Generators and other forms of capacity, such as DSPs, Dispatchable Loads and Interruptible Loads, and that this difference serves as a proper basis upon which to differentiate access to early capacity payments. That is, access to the early capacity payments should only be available to conventional energy generators and not is intended for forms of capacity which do not suffer extended periods post commissioning remedial work which would materially affect their reliability.

Rule Change Proposal

This Rule Change Proposal is that, for Reserve Capacity Cycles, any accredited Facility that is not a Scheduled or a Non-Scheduled Generator be precluded from being able to receive capacity payments prior to the close of the reserve capacity window in the year that the reserve capacity obligation first applies.

The effect of the Rule Change Proposal would be to preclude accredited DSPs, Dispatchable Loads and Interruptible Loads from being able to receive capacity payments prior to 1 October in the year that their reserve capacity obligation first applies.

Reason for the Rule Change Proposal

An outcome of the early capacity payment provisions of the market rules is that capacity provided by any newly accredited Facility is able to receive capacity payments as early as 1 June in the year that the reserve capacity obligation first applies. An unintended outcome of this change was that such newly accredited Facilities also included capacity from DSPs, Dispatchable Loads and Interruptible loads. These forms of capacity are mostly based on operational customer load and therefore are not capable of suffering extended post-commissioning re-works as is the case for generators. The oversight in the market rules of allowing all forms of capacity, irrespective of source, access to early capacity payments before the commencement of the capacity year places an extra and unnecessary cost on the market as indicated below. In 2011 the arrival of new DSPs for only two months created an extra cost to the market of approximately $2.3 million. It is expected the cost for 2012 will exceed $8 million.

If the early capacity provided by DSPs held value for the market in reliability terms then consideration of an early payment to DSPs perhaps is appropriate. However, this is not the case as discussed in the work undertaken by the Lantau Group when determining the value of excess capacity. Their assessment revealed that such is worth less than $1,000 per MW per year[1], clearly not the current rate of $131,000 per MW. Therefore in making payment to DSPs taking advantage of the reserve capacity window by arriving before 1 October the market will be potentially paying 131 times more than the benefit gained.

DSPs already treated differently

Some have argued that given capacity provides a singly defined service each form of capacity should be given the same payment. To do otherwise could be considered discriminatory and so be contrary to market objective (c). The market rules do not operate this way and instead of recognising a singly defined service expect differing performance and allocate different requirements to forms of capacity technology. In summary the differences in the market rules between conventional generation and DSP are:

STEM requirements
Generators (except intermittent generators being wind farms and land fill gas facilities as well as non-scheduled generators being ones less than 10 MW) must make STEM submission up to the level they are capacity credited. DSPs and non-scheduled generators therefore have a reduced risk by not being required to nominate into the STEM and so avoid being dispatched.

Dispatch merit order
If required for system purposes, System Management dispatches generators according to a bid price. Largely because DSPs have a limited number of hours of use the practice is to dispatch only after all generators have been dispatched.

Competitive balancing
Under competitive balancing all scheduled generators are required to submit bids into the market to deliver balancing services, which is in effect a price at which that generator will immediately either increase or decrease their generation. Non-Scheduled Generators have a similar requirement for decreasing generation. As a consequence a generator may or may not be dispatched given its price related to other generator prices. DSPs do not have such a requirement and do not participate in competitive balancing.

Market systems
DSPs are essentially capacity providers having no energy requirements other than in system emergencies. Therefore they do not need to provide to the IMO a resource plan (i.e., a plan under which a generator indicates it will meet it net contract position) as is the case for scheduled generators.

Communication systems
DSPs are not required to have 24/7 market systems to communicate with the IMO as is the case for generators. This recognises the different technology they have in the market.

Capacity refunds
Capacity refunds are differently determined for DSPs and generators. DSPs are charged a fixed rate for each failure, irrespective of the time of day or season, to participate when called

[1] It is understood that The Lantau Group have revised and updated these figures related to the volume of excess capacity as a cost curve. This curve appears to deliver a reduced value for excess capacity as the excess volume increases.

proportional to the number of certified hours the DSP has committed to provide over the Capacity Year (generally 24 hours). Generators are charged on a variable refund rate for each forced outage which varies by season, type of day and on-peak to off-peak.

ERA requirement - Licensing

Even though a DSP is remunerated via IMO capacity payments, just as some generators are, no DSP, regardless of size is subject to the licensing review process conducted by the ERA. By contrast, any new generator 30MW or larger is subject to that initial review by the ERA, which involves a determination by the ERA that the granting of a generation licence is not contrary to the public interest. If a generator of that size does not receive a licence then it would not be eligible for capacity payments from the IMO, even if the IMO has accredited that generation.

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b) Explain the reason for the degree of urgency:

It is most likely that a significant volume of new DSP capacity will be available for use by 1 June 2012 and so receive an early payment for four months before the start of the relevant capacity year costing the market more than $8 million. The worth of this excess capacity, applying the Lantau Group analysis, quickly approximately zero.

As noted above, it is considered that the additional cost imposed on the market due to **newly** accredited facilities that are not scheduled or non-scheduled generators receiving capacity payments prior to 1 October in the year that the reserve capacity obligation first applies cannot be justified based on the reduction in risk to power system security and reliability over the summer period when demand reaches system peaks.

Reading the RC_2009_11 rule proposal, participant comments and the market rule change reports it is clear that the early payment was intended only for Scheduled and Non-Scheduled Generators only, and not other forms of capacity including DSPs.

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c) 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)

4.1.26. Reserve Capacity Obligations apply:

(a) in the case of the first Reserve Capacity Cycle:

i. from the Initial Time, for Facilities that were commissioned before Energy Market Commencement;

ii. from the Trading Day commencing on the scheduled date of commissioning, as specified in accordance with clause 4.10.1(c)(iii)(7), for Scheduled Generators and Non-Scheduled

Generators commissioned between Energy Market Commencement and 30 November 2007, inclusive; and

iii. from the Trading Day commencing on 1 October 2007 for Interruptible Loads, Curtailable Loads or Dispatchable Loads commissioned after Energy Market Commencement; and

(b) for subsequent Reserve Capacity Cycles up to and including 2009:

i. from the Trading Day commencing on 1 October of Year 3, for Facilities that were commissioned as at the scheduled time of the Reserve Capacity Auction for the Reserve Capacity Cycle as specified in clause 4.1.18(a) or for Facilities which have provided Capacity Credits in one or both of the two previous Reserve Capacity Cycles;

ii. from the Trading Day commencing on the scheduled date of commissioning, as specified in accordance with clause 4.10.1(c)(iii)(7), or as revised in accordance with clause 4.27.11A or clause 4.27.11B, for Facilities commissioned between 1 August of Year 3 and 30 November of Year 3; and

iii. from the Trading Day commencing on 30 November of Year 3, for new generating systems undertaking Commissioning Tests after 30 November of Year 3; and

(c) for subsequent Reserve Capacity Cycles from 2010 onwards:

i. from the Trading Day commencing on 1 October of Year 3, for Facilities that were commissioned as at the scheduled time of the Reserve Capacity Auction for the Reserve Capacity Cycle as specified in clause 4.1.18(a) or for Facilities which have provided Capacity Credits in one or both of the two previous Reserve Capacity Cycles;

ii. from the Trading Day commencing on the scheduled date of commissioning, as specified in accordance with clause 4.10.1(c)(iii)(7), or as revised in accordance with clause 4.27.11A or clause 4.27.11B, for Facilities commissioned between 1 June of Year 3 and 1 October of Year 3; and

iii. from the Trading Day commencing on 1 October of Year 3, for new generating systems undertaking Commissioning Tests after 1 October of Year 3.

(d) for subsequent Reserve Capacity Cycles from 2011 onwards:

i from the Trading Day commencing on 1 October of Year 3, for Facilities that were commissioned as at the scheduled time of the Reserve Capacity Auction for the Reserve Capacity Cycle as specified in clause 4.1.18(a) or for Facilities which have provided Capacity Credits in one or both of the two previous Reserve Capacity Cycles;

ii. from the Trading Day commencing on the scheduled date of commissioning, as specified in accordance with clause 4.10.1(c)(iii)(7), or as revised in accordance with clause 4.27.11A or clause 4.27.11B, for Scheduled Generators and Non-Scheduled Generators commissioned between 1 June of Year 3 and 1 October of Year 3; and

iii. from the Trading Day commencing on 1 October of Year 3, for Facilities other than Scheduled Generators and Non-Scheduled Generators undertaking Commissioning Tests after 1 October of Year 3.

Alternatively, given that provisions under 4.1.26 (a), (b) & (c) will not be reused, are already redundant, these could be removed and (d) in a modified form remain.

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d) Describe how the proposed Market Rule Change would allow the Market Rules to better address the Wholesale Market Objectives:

Market Rule 2.4.2 states that the IMO must not make amending rules unless it is satisfied that the Market Rules, as proposed to be amended or replaced, are consistent with the wholesale 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.

Synergy considers that this Rule Change Proposal is consistent with the wholesale market objectives.

Specifically, Synergy considers that this Rule Change Proposal would:

- better achieve market objective (a) as it would reduce the cost to the market by not paying for DSP capacity where such payment does not provide commensurate market benefits;

- better achieve market objective (b) as it removes an incentive for the inefficient early entry of capacity from facilities that do not need the incentive and for which the market gains no additional benefit;
- better achieve market objective (c) by avoiding indirect discrimination in that market against market generators;
- better achieve market objective (d) by minimising the long-term cost of electricity supplied to customers from the South West interconnected system (see below); and
- is not inconsistent with market objective (e).

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

Synergy has not been able to identify any specific costs associated with this rule change proposal.

As outlined above, if all of the estimated capacity provided by newly accredited DSPs sought to receive capacity payments in 2012, the estimated additional cost to the market would be around $8 million. The benefit using the Lantau Group's assessment of the value of excess capacity is considerably less, approaching zero.

It appears reasonable to assume that for future capacity years, capacity from newly accredited facilities that were not scheduled or non-scheduled generators will similarly seek to receive capacity payments from the earliest possible date, being 1 June each year.

Given the unprecedented increase in capacity being made available to the market from newly accredited facilities that are not scheduled or non-scheduled generators, the resulting cost to the market may be significant.
