Wholesale Electricity Market
Rule Change Proposal Submission Form

RC_2008_24 – Commissioning Tests for Intermittent Generators

Submitted by

Name:	Shane Cremin
Phone:	9261 2908
Fax:	9488 7330
Email:	shane.cremin@thegriffingroup.com.au
Organisation:	Griffin Energy
Address:	L 15, 28 The Esplanade, Perth, WA, 6000
Date submitted:	10-10-08

Submission

1. Please provide your views on the proposal, including any objections or suggested revisions.

Griffin understands the principle of seeking to improve reliability by incentivising Participants developing intermittent generators to meet expected delivery timelines. However we question whether the capacity refund mechanism is the correct method through which the incentive should be managed, or whether the generator is not already appropriately incentivised. Griffin believes that there is a growing disconnect between the *"economically efficient, safe and reliable supply of electricity"* and the interpreted application of the Market Rules into real world commercial settings (in this case through the inefficient allocation of further risks to new entrant generators).

Absent a price on the externalities caused by carbon emissions, intermittent (renewable) generators are not economically efficient *per se*. We build intermittent generators for other social (and environmental) reasons rather than for the *economically efficient, safe and reliable supply of electricity*. To make these facilities competitive in our market, we subsidise them and apply regulations favourable to their operating characteristics (i.e. giving them must-run status). Under these conditions, the commercial drivers for investment in intermittent generators become pretty simple. Based on a forecast capacity factor (emanating from the prevailing wind resource, solar resource or wave resource), the intermittent generator requires a minimum payment for each MWh produced over its life. This payment, say $100/MWh, can be composed of any number of payments. Nominally, these are RECs, energy and in the WA WEM, capacity payments. Capacity payments are applied in an arbitrary manner. They are currently based on the cost per installed MW for constructing a diesel fired 160MW OCGT; and applied to the average MW capacity factor of the intermittent generator (typically around 35% for wind farms). There is currently consideration for adjusting this mechanism to greatly reduce the amount of capacity credits offered to wind farms.

The point is, the developer of the facility does not care where the income comes from, as long as the sum of these components adds to a commercial return (i.e. $100/MWh in our hypothetical case).

To finance the construction of an intermittent generator, a developer must be able to bilaterally contract the output of the facility, or be able to sell the output of the facility into a liquid market. In the case of WA intermittent generators, while they might be able to take some risk on selling their RECs into a national spot market[1], they are unable to reliable sell their energy into a liquid energy market. This means that they must bilaterally contract at least the black electricity component – comprising the energy and the capacity. How the black energy is apportioned between these two amounts is arbitrary, as it does not bear any relevance to the fixed and variable costs of the facility.

Considering this, a new entrant intermittent generator is thus incentivised to meet its project delivery dates by its contractual obligations rather than the capacity refund mechanism. ***The refund mechanism simply becomes an arbitrary financial penalty***. If a new intermittent generator expects that it will pay penalties 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. This is a commercial reality of project development where financiers protect their investments as a priority. The cost of financing additional risk premium is a cost that is then borne by the market.

The argument has been made that if the generator does not price in this cost, then others in the market (i.e. retailers) will price it in. However this is only true if the late delivery of an intermittent generator actually leads to higher market costs. Higher costs may be incurred through calling for supplementary reserve capacity (SRC), or through replacing the expected generation with higher cost generation in the market. The first of these should not be a frequent event (otherwise it should certainly not be referred to as 'supplementary') and should only incur a cost if the system reserve margin is breeched. Griffin does not believe there has been sufficient analysis to suggest that allowing an intermittent generator to cover the potential refund cost of each project development – and pass that cost on through higher wholesale pricing, is more efficient (cost effective) than incurring costs relating to SRC on an infrequent basis. The second potential market cost impost; that of higher priced electricity for the marginal unit not produced by the intermittent generator, will primarily be borne by the intermittent generator through its bilateral obligations in any case and is actually their main driver for ensuring timely delivery.

Griffin does not suggest that there is no rationale for trying to incentivise delivery of new capacity in a timely manner, however we believe that the interrelationship between the cost of incentivising reliability by penalising new entrant generators and the long term economically efficient production of electricity in the market has not been properly investigated. We also question whether penalising new entrant generators for late delivery actually produces any additional reliability benefits. Griffin contends that the IMO is naturally biased toward the outcome of reliability over economic efficiency. This results in a higher long term cost of electricity for end consumers than is otherwise warranted. While reliability generally comes at a price, this may not be the best outcome for the market.

Lastly, Griffin does not support the rationale that the same 'reliability incentives' should be imposed not only on differing types of capacity (we do not agree that all capacity should be treated equally – and in fact many types of capacity are treated differently in other sections of the Market Rules), but equally applied to new entrant generators and existing generators. New entrant generators face

[1] While MRET is a national scheme, it has become increasingly apparent that with the advent of a price on carbon, retailers will be incentivized to bundle their purchases of REC derivatives with the underlying MWh instrument that produced them. This is because as the price of carbon constrained electricity rises, the price of RECs will begin to fall (absent other supply/demand imbalances) and retailers will want the natural hedge of the bundled product. This means that WA based intermittent generators are likely to meet their minimum revenue stream by bilaterally contacting the whole bundled product rather than splitting the black electricity from the REC.

one off construction and development risks that are completely different to those faced by incumbent generators, which must manage their availability through maintenance programs over long periods of time.

For these reasons, Griffin does not support the rule change proposal.

2. Please provide an assessment whether the change will better facilitate the achievement of the Market Objectives.

The IMO contends that this rule change proposal supports market objective (a) by improving reliability. Market objective (a) states:

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

Griffin is not convinced that applying penalties to a new entrant intermittent generator facing construction risk will lead to a commensurate improvement in reliability; and that such an action is just as likely to decrease safety during the construction process. We also contend that the long term costs of applying penalties will lead to an inefficient outcome through higher wholesale electricity prices.

3. Please indicate if the proposed change will have any implications for your organisation (for example changes to your IT or business systems) and any costs involved in implementing these changes.

Griffin suggests that the main outcome of this proposed rule change will be an increase in the development costs and subsequent increase in wholesale electricity prices of future intermittent generation facilities.

4. Please indicate the time required for your organisation to implement the change, should it be accepted as proposed.

Not applicable.

Level 22 Forest Centre 221 St Georges Terrace Perth Western Australia 6000
Tel: (08) 9254 4300 Fax: (08) 9254 4399
Email: imo@imowa.com.au www.imowa.com.au