Wholesale Electricity Market
Rule Change Proposal Submission Form

RC_2008_34 – Funding of SRC in the event of capacity credit cancellation

Submitted by

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Submission

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

Griffin strongly objects to the proposed rule change. We neither support the proposal, nor do we believe the concept of allocating the costs of SRC to generators to be sensible or in accord with efficient market pricing principles. While we acknowledge the shortcomings of the current SRC provisions within the Rules and believe a significant review of the capacity market is required, Griffin is concerned that such a major reworking of our capacity market has managed to progress this far through the working group and rule change processes without being subject to appropriate scrutiny. We are confident, in light of a more thorough analysis of the changes being contemplated since the publication of the Draft Report, that RC_2008_34 will not be progressed.

<u>The policy perspective:</u>

The WEM is a capacity and energy market. As a small islanded electricity system, this structure was adopted specifically to encourage adequate investment in system capacity to meet the reliability targets set for the market. Reliability targets are key parameters in any electrical system. As with most network industries, after a certain point, achieving a marginal unit of reliability (or cost reduction, or performance etc) usually requires an exponential increases in the marginal cost. At some point, it is more efficient for the system to not support a marginal user, rather than incur the cost of increasing the capacity to do so. In electrical systems, this is usually expressed as the value of unserved energy (or Value of Lost Load – VoLL). In essence, reliability standards reflect the value that users should be willing to pay in order for the system to achieve that desired level. In the WEM, the market mechanism used to encourage sufficient investment to do this is the capacity market. The capacity market establishes a payment stream to generators, from users (via their retailers) in return for making capacity of sufficient reliability available. However capacity is not, and never can be, 100% firm. Capacity payments, as a premium levied on retailers, act to encourage a competitive market to supply the capacity. Competition in this market is based on both price (determined by the cost to the proponent of developing a facility, which is based on a number of variables) and reliability. The Capacity Refund Mechanism has the effect of lowering the value of unreliable capacity through penalty (refund) payments. The capacity market is driven by the annual volume of capacity required in the WEM in order to maintain reliability. Mechanically, this is achieved in two tranches. The first is to create capacity credits – artificial instruments with an arbitrary value based on the construction costs of a certain type of peaking facility – up to the amount of capacity required in a one-in-ten year peak demand forecast. It should be noted that changing this parameter to, say, a one-in-three year peak demand forecast will change the amount of capacity credits required. The second mechanism is to procure additional (supplementary reserve) capacity in the event that the primary capacity system has failed to meet the desired reliability, which it is designed to do on average once in every 10 years. *To put it simply, SRC is a fundamental component of the cost of capacity in our market. It is directly related to the price a user is willing to pay for the given level of reliability it brings. It is a cost that must be borne by the user.*

Another way to look at this is to examine the other component affecting reliability in our market – network adequacy. Users pay for the cost of transmission and distribution systems capable of delivering electricity at the required reliability level. The owner and operator of the network in the WEM, Western Power, receives a regulated return on its prudent investment in; and operation of network infrastructure (similar to peaking facilities receiving an administered price for providing reliable generation capacity). While Western Power may incur penalties related to reliability performance (as generators do with capacity refunds), if additional network adequacy is required, it is the end user, via network tariffs levied through the retailer[1], which bears the cost. Western Power will not be required to pay for, say, replacing aging and unreliable infrastructure with new assets.

Other markets use different drivers to deliver the required generation reliability. The gross pool NEM is an energy only market employing very high price caps ($10,000/MWh rising to $12,500/MWh in mid 2010). In this market, investment in spare (peaking) capacity is underwritten by the ability for generators to bilaterally trade hedge products, which essentially act as a proxy capacity payment. The standard product in this respect is the $300/MWh energy cap. This price is high compared to average pool prices, but is still far below the energy price caps. Retailers hedge against very high pool prices by buying these caps from peaking generators (caps trade at a premium for around $11/MWh to $15/MWh). The peaking generators earn a return on investment from a combination of this annual ‘capacity’ payment, as well as from their energy earnings[2]. The risk to peaking generators is that they are unable to generate when pool prices rise above the cap. In this instance, they must meet their contracted hedge obligation at pool clearing prices. Importantly, a peaking generator is able to account for this in the premium charged for the cap. This premium represents the expected long-run return from providing the cap and will include provisions for an inability to supply when required. *In other words, the fact that capacity is not 100% firm is built into the cap price.*

The practical perspective

If SRC costs must be borne by the customer, what is the best way to pass it through? At the moment, SRC costs have been socialised across retailers, according to their share of load. This seems appropriate. RC_2008_27 changed the methodology from a targeted allocation to a shared allocation. As a targeted allocation, SRC costs had the capacity to ‘knock a retailer out of the market’. The argument against adopting RC_2008_27 was one of efficiency – where retailers that

[1] Or, if the cost is levied to generators as a capital contribution, through increased wholesale electricity prices.

[2] When pool prices rise above the cap level, generators are able to earn inframarginal revenues.

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failed to manage their capacity obligations should be allowed to exit the market. This was countered by an argument of competition; including concepts around market power and practicality. It seemed incongruous in a developing market that the out-workings of an artificial instrument, which could easily be manipulated by large holders of capacity in the market, could determine the fate of an otherwise cautious and efficient operator. The same applies to the notion of allocating this cost (or a portion of it) to generators. To begin with, there is little or nothing to gain by threatening generators with what amounts to a penalty for an inability to supply capacity. Generators have more than enough incentive to maintain availability in the market. The Capacity Refund Mechanism is specifically designed to do this (in fact, allocating SRC costs to generators would completely undermine the pricing signals of the Capacity Refund Mechanism). Additional to this are the bilateral obligations of energy producing facilities; and for late new-entrant facilities there is the pressure, applied by project financiers, to achieve practical completion and pay down expensive bridging / construction debt facilities. More importantly, the issues dealt with in RC_2008_27 do not disappear when applied to generators. The cost of an SRC event, even capped at half of annual capacity payments, will be very likely to send a project financed generator insolvent if incurred (it should be understood that if incurred, the SRC cost will be <u>additional</u> to the significant penalties attributed to capacity refund payments, not to mention any energy supply obligations that would need to be met in the market). Investigations to date suggest that SRC will also be uninsurable for project financed generators. Even if it were, standard Business Interruption insurance is available at present with deductible periods of around 45 to 60 days. This means that SRC events would be unlikely to be covered under the deductible periods. On top of this, the burn rate for insurance cover after the deductible period is not close to covering the potential SRC liability. Additionally, Insurers approached in local and international markets have little appetite to offer specific (non-standard) products to cover such a contingent liability. So reallocating costs from end users (via the Market Customer) to generators would reintroduce the issue of a loss in competition in the market – this time as generation proponents either exit the market due to insolvency, or are dissuaded from entering a high risk environment.

A point should be made here that an early argument made in favour of this rule change was that 'risks should be borne by those best placed to manage them' – and that the cost of SRC (attributed to generator failure) should thus be levied on generators. Griffin contends that this generally accepted axiom for risk management is ill conceived in this application. A cursory analysis of the situation will show that the argument is superficial at best and that much more rigour is required to understand the true basis of the efficient allocation of costs. Casting aside for a moment the arguments that capacity is not 100% firm; that the less reliable the capacity, the lower the value placed on that capacity in the market; that end users are the beneficiaries of; and should bear the cost of capacity; and that as a penalty to generators, SRC costs are unlikely to bring any additional reliability value to the market: Then, if the costs of SRC (due to generator failure) <u>was</u> allocated to generators and that generator <u>was</u> actually able to insure against the cost: Would this be the most efficient allocation of costs in the market? Effectively, in order to prevent a volatile insolvency-causing event, a generator would be required to insure its facility at all times. So a generator's method of managing risk in this case is through ex-ante insurance, or insuring every MW for every year it is in operation (ten-in-ten years). If the market simply incurs the cost of SRC, an ex-post management of the risk, then this becomes a one-in-ten year event. Given that insurance costs are unknown (if they were available), it is difficult to compare the efficiency of allocating SRC costs to generators rather than leaving them with Marker Customer. Additionally, an SRC event might not be attributable to generators, in which case the market bears two costs, that of the generators ex-ante risk management as well as the full SRC cost.

It can be argued that generators, in effect, already contribute to SRC costs through the capacity refund mechanism. When refunds are paid while there is a surfeit of capacity in the market, then this transfer of wealth from generators is a windfall gain to retailers. In a gross pool market, this wealth transfer would offset the replacement energy purchased by the retailer at higher pool prices, attributable to the loss of the generator (equivalent to a hedge by the retailer). However in a bilateral market, the replacement energy is procured by the generator to meet contracted supply obligations. A generator effectively incurs a double cost for the outage (it should be noted that a small amount of energy, typically 5%, has historically been traded in the STEM and balancing markets and hence retailers might have a small exposure to higher wholesale prices). Some quick rule-of-thumb analysis shows some of the costs and revenues likely to be involved:

Mechanism	Average Annual Cost Base		
SRC Costs (priced at $10,000/MW incurred once in ten years)	SRC required	2 weeks (10days x 10hrs)	4 weeks (20days x 10hrs)
	100MW	$10M	$20M
	150MW	$15M	$30M
	250MW	$25M	$50M
Capacity Refund Revenue (95% of forced outage revenue allowing 5% to offset STEM/balancing uplift)	Forced outage rate	5,146MW @ $144,235/MW	
	4%	$28M	
	5%	$35M	
	7.5%	$53M	
Increase of reserve margin	Increase of	@ $144,235/MW	
	100MW	$14.4M	
	150MW	$21.6M	
	250MW	$36M	

While a rather crude analysis, the table suggests that the costs of SRC could be approximated as an annual additional charge which increases the reserve margin. Smoothing the volatile costs of SRC in this way would be beneficial to Market Customers. It also suggests that under the current arrangements, generators already pay for the costs of SRC in the market, meaning that generators are subsidising the end users of capacity – or more correctly, that generators are hiding the price signals of the value of the marginal price of supply by incorporating this cost into their average wholesale electricity prices. This current practice would appear to contradict Market Objective (e).

Other implications

SRC costs as a penalty to incentivise behaviour (in this case the management of reliability risk) is inherently flawed. Capacity is never 100% firm, though is generally very reliable. Less reliable generators will be devalued in the market through the Capacity Refund Mechanism. There has been no evidence provided that penalties such as the one contemplated in RC_2008_34 improve reliability[3] and the lack of recognition of Force Majeure in the Rules means that generators can never fully protect themselves from forced outage costs. Also, the allocation of SRC costs to generators serves to undermine the price signals of the existing Capacity Refund Mechanism. This

[3] Anecdotally, Verve energy, with the largest generation fleet in the SWIS, experienced a forced outage rate in 2008 of 5.3%, which is higher than it had recorded in previous years under a less punitive capacity refund mechanism. This includes an outage to the flagship Collie A Power Station at a time of extremely high energy prices during the Varanus Island incident. Similarly, Newgen, with the newest commissioned facility on the SWIN, has experienced availability issues very recently at a time when STEM prices are above average and well above their SRMC. This indicates that the IMO's 'incentives' do little to incentivise generators in the face of many types of forced outage incidents.

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would suggest that, in order for RC_2008_34 to improve the Market Objectives, the Capacity Refund Mechanism will implicitly be substantially altered. The IMO has been very reluctant to review the capacity refund mechanism since RC_2007_08 implemented the existing structure.

The WEM is predominantly a bilateral market. This has some important implications. Project finance for new entrant generators requires long term off-take contracts with creditworthy counterparties. The contracted price required to make a return on any new investment is set, with the prevailing risk costs built into that price. Any additional costs (including regulatory costs) imposed on the generator and not included in the project modelling are unlikely to be passed through to end users (as an efficient price signal reflecting the true costs in the market – as is the case in the gross pool NEM). They are thus borne by the generator. This has the effect of eroding generator returns. This can lead to a secondary effect where further losses are incurred through the triggering of; and subsequent recovering of project finance debt covenants. Reallocating significant costs in a bilateral market should only be contemplated if the parties with the costs being reallocated to are to be compensated for their losses. Not to do so may lead to higher risk premiums for future investments – an inefficient cost to the market.

The signals this proposed rule change sends to new investment proponents are severe. Every new facility entering the market will be, in their first four months of operation, exposed to enormous risks. Consider a project financed generation proponent bringing 160MW of new capacity into the market[4]. The generator faces one-off construction risk, including IR risk; equipment manufacturing risk; equipment transport risk; and new equipment failure risk, among other events typically covered by Force Majeure clauses. If the new entrant generator is still not commissioned by January of its first year, it is classified as being under an extended forced outage. If the extended forced outage carries over the four month hot season and in this time an SRC event is called, the generator is liable for SRC costs of up to $13.1M (based on 2011 capacity prices). This is on top of the capacity refunds it is paying, which by the end of the hot period will reach the cap of its annual capacity revenue (the penalty equates to around 75% of annual capacity revenue when the capacity revenue it receives in this period is netted off). This is an additional cost of around $19.7M – or a combined potential liability for a 160MW new entrant plant of $32.8M within the first four months of operation (excluding any contracted supply obligations, additional costs associated with extended construction timelines and additional bridging finance costs). This can hardly be an appropriate signal to send to new investors.

<u>The IMO workshop</u>

Griffin believes the IMO workshop was a necessary additional step in this rule change process. It became evident during this forum that there were many effects of the proposed rule change not properly addressed in the preceding workings. Griffin agrees with the recommendation of workshop host MMA that RC_2008_34 should not proceed and that a broader review of the framework for SRC should be undertaken. However, Griffin would like to comment on some of the analysis and observations contained in the MMA report.

MMA correctly states that Griffin raised the issue of insurance (and the apparent lack of appetite in the insurance market to offer appropriate products to cover generator SRC costs). MMA claims:

> *"Griffin Energy opposed the rule change with regards to the extended forced outage scenario on the basis of a claim that this was a new uninsurable impost on the Bluewaters project. The Bluewaters units are not expected to meet their planned*

[4] The annual capacity price is determined by cost of a new 160MW OCGT.

> *commissioning date and therefore there is an increased risk of the need for SRC and additional costs imposed on Griffin Energy." MMA Report pg.1*

Griffin wishes to correct this interpretation of our remarks. Bluewaters Unit 1 was delayed in the 2008/09 capacity year and its delay would in no way be impacted by RC_2008_34. Additionally, the majority of the load contracted to Bluewaters Unit 1 is a new system load (the Boddington Gold Mine), which is also suffering commissioning delays. Therefore, the risk of SRC as a physical result of Bluewaters 1 being late was minimal. Bluewaters Unit 2 is scheduled for delivery in November 2009, in time to meet its capacity obligations for the 2009/10 capacity year. Bluewaters Unit 2 construction is tracking to schedule. Griffin does not anticipate any additional SRC risk attributable to Bluewaters Unit 2. More generally, Griffin's position with regard to insurance was implied for all (project financed) generation facilities, and indeed is probably more relevant to large peaking facilities. The issue was raised to point out a flaw in the rule change proposal – that generators would face risks that would likely lessen competition in the generation sector. We also point out that, in 2009, Griffin will become the third largest retailer in the SWIS, supplying approximately 10% of all electricity consumed. As such, Griffin has a commercial imperative to balance its view of market impacts to generators and retailers.

Section 3.5 of the MMA report discusses capacity pricing issues. MMA propose that the Reserve Capacity Price might include a benchmark cost component for forced outages – based on the premise that capacity can never be 100% firm. While an idea with merits, Griffin believes it serves to highlight the inherent flaws of a capacity market in a predominantly bilaterally traded electricity market – where all providers of capacity are treated equally. In short, base load generators are penalised by higher reserve capacity prices. A base load generator bilaterally contracts the output of its plant based on the Long Run Marginal Cost (LRMC) of production, that is, the contract price required to make a return against the capital invested (and financed) and the Short Run Marginal Costs (SRMC) of producing electricity. Capacity payments mean little to the base load generator. Its true cost of capacity is far in excess of that of a liquid fired OCGT (as its SRMC is typically much less). This capacity cost is inherent in the bilaterally contracted electricity price. The IMO capacity payments (required by a retailer to meet its IRCR), is simply passed on to the contracted retailer, who in turn, along with additional capacity to meet its NTDL and TDL reserve capacity uplifts, make payments back to the IMO as part of the settlement process. The retailer would not purchase capacity from a base load generator to meet its share of reserve margin. It purchases capacity as a component of electricity supply. Contrarily, a retailer might purchase capacity from a peaking facility specifically for the purpose of meeting its share of the reserve margin (as well as providing high priced energy in peak periods). The revenues of peaking facilities are therefore related to the price of capacity. They are not for base load plants. In fact, for base load plants, the price of capacity is only viewed as a liability. It is the reserve capacity price that sets the penalty value of capacity refunds. So making capacity prices higher only serves to increase the liabilities of a base load plant. Of course an outage from a base load plant will have greater impacts from an energy supply point of view (though the associated costs are generally met by the generator rather than passed through to the market). This highlights the issues with trying to incentivise non-peaking plant using rules and cost-templates based on peaking facilities. Efficient pricing dynamics become skewed by artificial pricing (and risk) mechanisms.

<u>The way forward</u>

SRC is a component of the true cost of capacity in our market. It is based on the price users are willing to pay for reliability. It should be borne by users and thus is currently correctly placed as a socialised cost attached to retailers. Griffin believes that the way forward on this issue is to tackle the nature of the SRC cost itself. The WEM is heavily price regulated. The volatile and uncapped nature of SRC is clearly out of step with the rest of the market and creates difficulties for retailers in managing such a contingent liability. A smoothed cost structure, more akin to the annual

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administered capacity price, would much more easily be managed by Market Customers. Griffin believes there is merit in looking at the present Capacity Refund Mechanism and how these payments might be most efficiently distributed or applied within the market to better achieve capacity adequacy. Griffin is adamant however that a significant re-working of the capacity market, such as that proposed by RC_2008_34, cannot progress without a thorough examination of the existing regime.

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

As described above, Griffin does not believe that allocating SRC costs to generators undergoing a forced outage will better facilitate any of the market objectives and will negatively impact some:

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 unclear if the cost incurred by generators of SRC events (which may be only a portion of the actual cost to the market) is an efficient allocation of costs. Due to the fact that an SRC event would likely bankrupt a project financed generator, generators must find a way of mitigating this possibility. If an insurance product were to become available that achieved this, there is no evidence that insuring every MW ten-in-ten years will be more efficient than simply incurring (and socialising) the cost of the one-in-ten year SRC event. Also, the SRC cost might actually be incurred as a result of other market events – such as poor forecasting or transmission failure, meaning the market incurs the cost of SRC <u>as well as</u> the cost of generator risk mitigation measures. In other words, this risk might be best managed on an ex-post basis (incurring the SRC cost) rather than an ex-ante basis (insurance or through higher CAPEX due to redundancy being engineered into capacity).

Additionally, there is no evidence that allocating this risk to generators will actually lead to any improvement in reliability of capacity (and hence reduction in SRC costs).

b. *to encourage competition among generators and retailers in the South West interconnected system, including by facilitating efficient entry of new competitors*

Applying this rule will have the effect of lessening competition as project financed generators exit the market through insolvency events; or are disincentivised to invest in an inherently risky market in the first place.

As for the objective of "Facilitating efficient entry of new competitors", new competitors are those seeking to successfully implement their first investment in the market. A new plant faces a potential cost penalty of around $32.8M if delayed for 4 months (based on 2011 capacity prices). This is clearly an unacceptable risk for a potential new entrant generator.

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*

Any rule that has the potential to penalise one type of generation over another does not better advance this objective. For example, intermittent generation is less reliant on capacity payments (it derives additional income from renewable subsidies not available to other generation types) and so will be exposed to lower SRC cost caps. This simply highlights the differential nature of capacity in any market.

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

As per objective (a), the potential exists to double up on costs by both incurring SRC costs from forecast error (or other non-generation related capacity shortfalls) as well as generators passing through costs it incurs through ex-ante risk mitigation (insurance or increased plant redundancy).

As per objective (b), lowering competition between generation proponents is likely to lead to higher long term wholesale prices.

e. to encourage the taking of measures to manage the amount of electricity used and when it is used

Current practices (of generators subsidising SRC costs through capacity refunds when capacity is available) blunts the price signals associated with the marginal cost of supply by increasing the average cost of wholesale electricity. Making generators contribute further by directly allocating SRC costs to them will exacerbate this. End users should be exposed to the true costs of meeting marginal supply. This will better achieve objective (e)

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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.

As a developer of significant generation facilities, this proposal will lead to higher working capital costs for future new generation developments, in order to meet potential SRC costs due to late commissioning.

As an operator of existing assets, this proposal will lead to:

- Additional costs incurred in the mitigation of SRC risk through taking out additional insurance (if possible), or through building in increased redundancy (e.g. it may be cost effective to construct 100MW of additional and redundant peaking facility for a base load plant rather than purchase insurance products if the cost of such products were more than approximately $0.75/MWh). These costs will be unlikely to be passed through existing 15+ year bilateral contracts.
- It is unknown what additional prudential requirements would be required based on the additional liabilities (an issue not yet addressed by the IMO)?

As a retailer, this proposal will reduce the exposure of our fixed bilateral contracts to SRC costs (at the expense of generators).

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

Not applicable.

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