ERA Secretariat Submission to Electricity Market Review: Capacity Position Paper

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Economic Regulation Authority
WESTERN AUSTRALIA

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Economic Regulation Authority
Perth, Western Australia
Phone: (08) 6557 7900

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INTRODUCTION

The Secretariat of the Economic Regulation Authority (**Secretariat**)[1] welcomes the opportunity to comment on the Electricity Market Review (**EMR**) Position Paper on Reforms to the Reserve Capacity Mechanism (**Position Paper**) published by the Public Utilities Office (**PUO**).

The Secretariat supports the general model proposed in the position paper on the Reserve Capacity Mechanism (**RCM**) of the Wholesale Electricity Market (**WEM**). The Secretariat's comments in this submission provide potential modifications to the proposed arrangements rather than major restructuring of the arrangements.

The Secretariat's suggested improvements include:

- holding the first capacity auction on a defined date rather than waiting until excess capacity reaches 5% (Time until Auction);
- taking care that conservatism in ensuring targets in different parts of the RCM do not add up to ensure a persistent large excess of capacity (Creeping Conservatism);
- compensating Demand Side Management (**DSM**) when it dispatches rather than partly through the RCM auction (Removing DSM from the Auction);
- placing restrictions on planned outages as proposed in the Position Paper, but removing the discretion of the Australian Energy Market Operator (**AEMO**) not to enforce current rules (Planned Outage Restrictions);
- continuing to return outage refunds to market customers, rather than to generators as proposed (Refunds Recycling);
- tightening of technical specifications and fuel supply availability in the capacity certification process so that generators are practically available when required rather than merely 'not-on-outage' (Technical Parameters for Capacity Accreditation); and
- removing a potential double payment to DSM during the transition period (Value of DSM during Transition Period).

These changes are detailed below.

AIM OF WHOLESALE ELECTRITY MARKETS

In framing its response to the Position paper, the Secretariat refers to the WEM objectives, which are contained in Market Rule 1.2.1 and in Section 122 of the *Electricity Industry Act 2004*. Rule 1.21 is replicated below.

> 1.2.1. The objectives of the market are:

[1] This Submission has been made by the Secretariat as a Member of the Authority is currently advising the EMR in relation to the RCM.

(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.

Consistent with the WEM objectives, the Secretariat considers that, compared to an energy-only market, a capacity-energy market aims to[2]:

- induce the optimal amount, cost and type of generation and DSM investment;
    - in particular, capacity markets are often used to mitigate against the 'missing money' problem, which can occur if the price cap in an electricity market is set too low[3];
- substitute for the lack of a robust demand side response in electricity markets, including:
    - inability of consumers to see the real-time electricity price and their lack of options to reduce demand; and
    - consumers' inability to express willingness to pay for reliability;
- reduce the volatility of electricity prices compared with an energy-only market; and
- reduce potential misuse of market power.

The Secretariat has framed its comments on the Position Paper against these objectives.

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[2] Crampton, P. and S Stoft, "A Capacity Market that Makes Sense", *Electricity Journal, 18, 43-54*, August/September 2005, pp2-3, http://www.cramton.umd.edu/papers2005-2009/cramton-stoft-a-capacity-market-that-makes-sense.pdf.

[3] Cramton, P., A. Ockenfels, and S. Stoft, "Capacity Market Fundamentals", *Economics of Energy & Environmental Policy, 2:2.*, 2013, p4, http://stoft.com/wp-content/uploads/2013-05_Cramton-Ockenfels-Stoft_Capacity-market-fundamentals.pdf.

FINAL AUCTION DESIGN

Auction Design

Summary

The Secretariat agrees that a capacity auction is the best mechanism for establishing a market price for capacity. Auctions are run in North American capacity markets and, while the markets are constantly evolving, all appear to be functioning successfully.

The Secretariat supports the basic design of the proposed capacity market outlined in the Position Paper. In particular, it supports:

- a sloped auction demand curve to reduce capacity price volatility;
- the auction being 'all-in', with capacity contracted bilaterally being required to participate;
- a three year forward auction period;
- that there is currently no case to include annual reconfiguration auctions;
- the zero price crossing point of the auction demand curve should be larger in percentage terms in a small market like the WEM as compared to larger markets in the US; and
- capacity providers should all be offered the same commitment period through non-discriminatory auctions.

Auction Demand Curve

The Secretariat notes that one aim of a capacity market is to reduce energy price volatility compared to an energy-only market. The associated capacity payment can stabilise returns to generators relative to an energy-only market and give generators greater confidence that their projects will earn their required return. A capacity market can be beneficial to consumers if it helps to achieve the optimal amount and mix of generation capacity.

For optimal investment to occur, the price of one additional Megawatt (**MW**) procured should reflect the value to consumers of that one MW. A reality of electricity markets is that the value of additional capacity drops rapidly once the annual Reserve Capacity Requirement (**RCR**) has been procured.[4] The use of a sloped demand curve[5] (as opposed to being almost completely vertical) is a compromise to avoid extreme capacity price volatility (the zero-infinity problem[6]) and allow the auction to function sensibly.

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[4] Public Utilities Office (PUO), *Position Paper on Reforms to the Reserve Capacity Mechanism*, Perth, 3 December 2015, p17, https://www.finance.wa.gov.au/cms/uploadedFiles/Public_Utilities_Office/Electricity_Market_Review/Position-Paper-on-Reforms-to-the-Reserve-Capacity-Mechanism.pdf .

[5] A less-steep demand curve has low price volatility, but high quantity volatility, as compared to a steeper curve.

[6] The zero-infinity problem occurs when a small shortage of capacity relative to a target produces a very high capacity price if there is not enough time for the market to respond. Conversely, a small excess of capacity can produce a near zero price. Source: The Lantau Group, 2014, *Improving Western Australia's Reserve Capacity Market: Steps and thoughts to Date*, presentation accessed from: http://www.lantaugroup.com/files/ppt_wa_mtt.pdf .

If the demand curve is set at the correct position to procure the RCR (or slightly more) at the benchmark new entrant price, but is too shallow (near horizontal in the extreme case), the auction will frequently procure excess capacity that provides much less value to customers than it costs. Consequently, the auction demand curve should be sufficiently downward-sloping to allow the auction to function, but not so steep that the resulting price variability dulls investment signals.

The Secretariat notes that there is no way of precisely determining the optimal demand curve for an auction. The Secretariat supports setting a curve for a small market like the WEM that is shallower than the settings for the much larger North American markets and that a slope consistent with a zero capacity price of 15-20% above the RCR seems appropriate.

The Secretariat supports the concept of a convex demand curve as has recently been adopted in the PJM Market[7]. A convex demand curve minimises the chance of procuring too little capacity because the price declines relatively slowly once the target level of capacity is reached or exceeded by a small amount.[8]

The Secretariat also supports shifting the demand curve to the right of the RCR as proposed in the Position Paper to ensure there is no persistent under-procurement of capacity. The Position Paper[9] suggests shifting the demand curve to cross the benchmark new entrant cost at 5% above the RCR, so that the auction will under-procure the RCR one in four years on average.

Footnote 18[10] of the Position Paper suggests considerable analysis has been undertaken to determine the placement of the auction demand curve, but this analysis has not been included with the Position Paper. The Secretariat recommends the EMR publishes (to the extent possible) its analysis of the costs and benefits of the selected parameters for the final demand curve.

Other Auction Parameters

The Position Paper does not specify an exact commitment period during which a price obtained in an auction would apply, but notes that North American Markets have been able to procure sufficient capacity without offering long-term commitments to suppliers. The Secretariat supports this position.

The Secretariat has no particular expertise in auction design and so has not commented on the proposed sealed-bid auction format.

Creeping Conservatism

In framing the final demand curve, the Secretariat suggests that the proposed industry working group[11] consider the potential for conservatism in the auction design to add up to a large and persistent over-procurement of capacity.

The Secretariat notes that there is conservatism (deliberate over-procurement) in many of the design features of the proposed auction mechanism, including the:

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7 PUO, op.cit., p20.

8 Crampton and Stoft, op. cit., pp8-9.

9 PUO, op.cit., p25.

10 Ibid., p25.

11 Ibid., p15.

- crossing point at which the benchmark price applies, which is approximately 5% above the RCR[12];
- convex demand curve, where the price falls away slowly once a certain level of excess capacity is reached;
- zero price point being set at 15-20% above the RCR;
- the incentive for the RCR forecaster to over forecast, as detailed in the ERA's submission to the EMR Discussion Paper;[13] and
- the choice of the benchmark unit (see Removing DSM from the Auction below).

The Secretariat agrees that some level of deliberate average over-procurement is necessary to ensure sufficient capacity in most years. However, there is some risk that the collective impact of the parameters will be greater than intended.

The Secretariat recommends that, further consideration be given to the methodology to ensure the overall level of conservatism is set to the desired level.

Removing DSM from the Auction

The Secretariat notes that the benchmark generator used to calculate the Maximum Reserve Capacity Price (**MRCP**), which is to be renamed the Benchmark Reserve Capacity Price (**BRCP**) is currently a 160 MW open-cycle gas turbine generator[14]. However, to date the market has consistently procured more than the RCR at a discount to the estimated BRCP[15] (i.e. the Final Reserve Capacity Price (**RCP**) has been less than the BRCP). Potentially this is because technologies with capacity costs lower than the BRCP have been available in the WEM.

Consider the situation in a stylised capacity market as shown in Figure 1 below. The BRCP is set at P(B) and the auction demand curve is set so that in equilibrium, if the technology behind P(B) is the lowest cost available to the market, the market exactly procures Q(RCP) at P(B).

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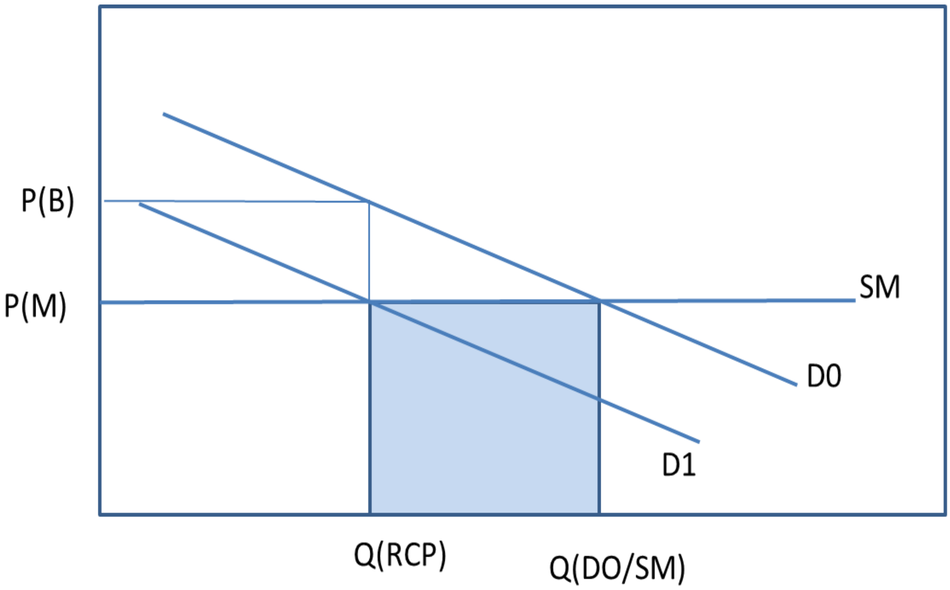
[12] Ibid., p25.

[13] While this is not in the scope of the Position Paper, its impact should be considered when setting the capacity procurement arrangements. Source: Economic Regulation Authority, 2014, *Submission to the EMR Discussion Paper*, pp7-8, https://www.finance.wa.gov.au/cms/uploadedFiles/Public_Utilities_Office/Electricity_Market_Review/ERA.pdf.

[14] Australian Energy Market Operator (**AEMO**), *Maximum Reserve Capacity Price*, http://wa.aemo.com.au/home/electricity/reserve-capacity/maximum-reserve-capacity-price/maximum-reserve-capacity-price-overview .

[15] The choice of technology that sets the BRCP is not in the scope of the Position Paper. However, the Secretariat notes that an incorrect choice of benchmark can adversely affect the performance of any centralised capacity procurement system.

Figure 1: Capacity Market Outcome under Different Benchmark Technologies



However, if a lower annual capacity cost technology becomes available in unlimited amounts at price P(M), then the system will procure additional capacity over and above Q(RCP). The total amount procured will equal Q(DO/SM) and the market clearing price (RCP) will fall to P(M).

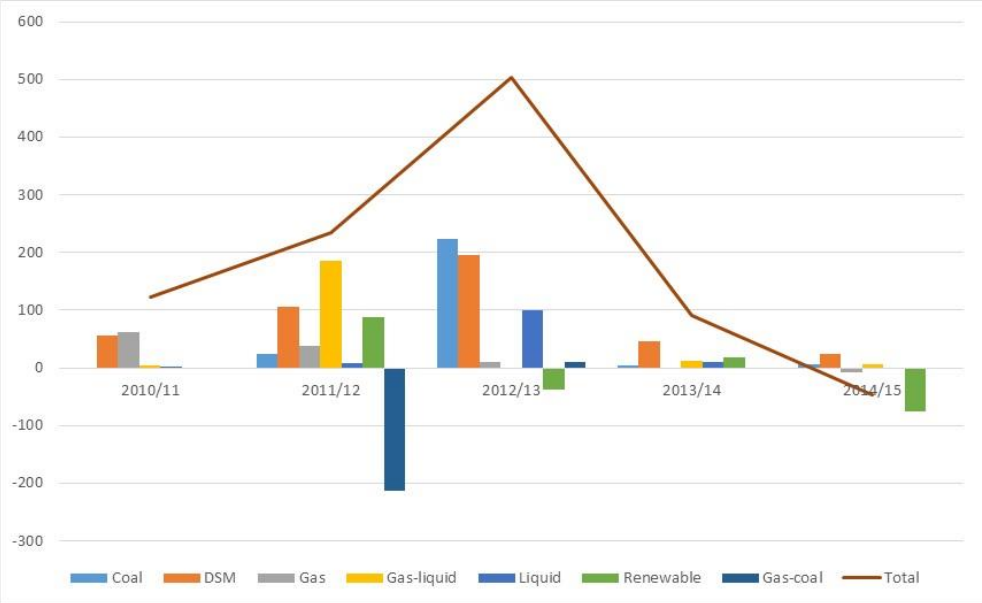
The total value of capacity procured at P(M) and Q(DO/SM) is, if the demand curve is steep enough, equal to or lower than if Q(RCP) was procured at P(B). However, the market will procure more capacity than it needs at P(M). It could reduce the cost to the market by the shaded area in Figure 1 by changing the demand curve to D1 and procuring Q(RCP) at an unchanged price P(M).

The Secretariat notes that DSM accounted for most of the new capacity that entered the market in 2013/14 and 2014/15 (as shown in the chart below). While current arrangements have not revealed the price at which DSM is willing to enter the market[16], the Secretariat believes that DSM has capital costs that are significantly below the current BRCP. While not completely certain, this is still likely to be the case despite the changes to DSM capacity baseline accreditation proposed in the Position Paper. Consequently, DSM is likely to play the role of the lower cost technology in Figure 1 above[17] and could set the RCP once auctions commence in the WEM.

[16] The price at which DSM is willing to enter is not known, because the RCP did not fall far enough to reveal this value under the current system.

[17] The actual supply curve of DSM in the WEM is probably upward sloping. The perfectly elastic supply curve in Figure 1 is used for simplicity.

Figure 2: Capacity Additions to the WEM, 2010/11 to 2014/15



Source: ERA, *2012 Wholesale Electricity Market Report for the Minister for Energy*, April 2013, p40, http://www.erawa.com.au/cproot/11455/2/2012%20WEM%20Report%20to%20the%20Minister%20for%20Energy.pdf .

This would imply that the BRCP should be based on the cost of DSM. However, the Secretariat considers that it would be challenging to calculate a DSM-based BRCP.

Normally a capacity market design assumes that the least expensive (benchmark) capacity generator will have the highest energy dispatch cost, which is used to set the market energy price cap. In such a market the benchmark generator makes a return on capital through the capacity market, and exactly offsets its variable costs when dispatched in the energy market. Other generators gain a return on capital through a combination of receiving the capacity price as well as revenue from the energy market that exceeds their costs when the benchmark generator sets the Balancing Price[18].

In the WEM, DSM can only offer energy at the Alternative Maximum Short-Term Energy Market Price[19], which in most cases is below the cost of 'dispatch' (often approximated by Value of Lost Load or **VOLL**)[20]. Consequently each DSM provider will offset expected losses in the energy market with an allowance in their capacity offer.

This calculation will be very individual in nature depending on exact costs and expectations of being dispatched, so it will be difficult to construct a single benchmark DSM capacity price. While selecting a technology for the BRCP is at best an approximation for any technology, the chances of an error are greater for DSM.

18 This assumes that these generators do not have bilateral contracts which include capacity payments.

19 This is currently $377.00/MWh. Source: AEMO, *Price Limits*, http://wa.aemo.com.au/home/electricity/market-information/price-limits .

20 The maximum energy price in the WEM could be changed to VOLL, but the WEM would effectively become an energy-only market.

An alternative to allowing DSM into the capacity auction and receiving a capacity payment would be to simply pay DSM an energy-only price (e.g. VOLL[21]) when dispatched. In this way, the benchmark generator in the capacity auction could be set with more certainty and would be more relevant to most generators in the market. [22]

This system could work by first running a DSM procurement process to estimate the amount of DSM available at VOLL for dispatch if required, then reducing generation capacity to be procured at auction by the amount of DSM procured. Traditional generators would then enter the auction to effectively procure the RCR minus DSM.

When dispatched DSM would not affect the balancing price (i.e. VOLL would not be paid to traditional generators), as this would tend to lead to over-procurement of traditional generation capacity.[23] Instead the cost of DSM purchased would be allocated to customers consuming electricity during the relevant Trading Intervals. That is, there would be two prices in the market when DSM is dispatched:

- the balancing price received by traditional generators; and
- the DSM price, which would be received by DSM when dispatched.

The Secretariat acknowledges that this proposal does introduce some complexity as the system operator will have to estimate two parameters, the RCR and VOLL, whereas traditional markets only have to estimate one or the other. Misestimating VOLL could lead to greater or lower than optimal generation capacity being procured at greater cost to the market.

However, this proposal would compensate DSM much more in line with its actual costs, given that DSM is a 'negative demand' with low capital costs but high dispatch costs. It would also align the quantity of DSM dispatched to the actual amount required by the market. Finally, the AEMO would not need to estimate a 'typical' capacity price for DSM, which would be a calculation fraught with uncertainty.

The Secretariat recommends that, once capacity auctions commence, DSM should be compensated outside of the RCM system as outlined above.

Capacity Availability and Refunds Recycling

Summary

The Secretariat understands the Position Paper's proposals regarding capacity availability are based on Rule Change RC_2013_20 as previously proposed by the Independent Market Operator (**IMO**)[24]. The Secretariat supports the Position Paper's attempts to improve incentives for capacity availability. In particular, the Secretariat supports:

- basing refunds on availability during shortage trading intervals (dynamic refunds); and

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[21] The VOLL for National Electricity Market (**NEM**) customers directly connected to the transmission network is used as the price cap in the NEM. Source: PUO, op. cit., p49.

[22] The Secretariat notes that a recent Supreme Court of the US ruling has upheld a Federal Energy Regulatory Commission ruling that DSM and traditional generators be treated equally.

[23] Stoft, S., *Power System Economics: Designing Markets for Electricity 1st Edition*, 2002, New York: John Wiley and Sons, p185.

[24] PUO, op. cit., p42.

- limiting the number of trading intervals that a generator may schedule planned outages over a 36-months period.

However, the Secretariat considers several areas in the Position Paper's proposed model could be improved. These are detailed below.

Planned Outage Restrictions

The Position Paper correctly identifies the high planned outage rates of certain generators as a concern.[25] The Secretariat supports restricting the total trading intervals that a facility may schedule planned outages over a 36-month period from 30 per cent to 20 per cent in Market Rule 4.11(h) as proposed in Rule Change RC_2013_09[26].

However, the Secretariat notes that the outage limit in Rule 4.11.1(h) is only useful if enforced, given that the Rule allows AEMO some discretion as to whether to de-rate a participant's capacity. The Secretariat notes that certain facilities in the past had outage rates in excess of the current provisions in Rule 4.11.1(h) but were not de-rated by the (then) IMO.

For example, Table 6 of the ERA's 2012 WEM Report to the Minister[27] contains evidence of several generation facilities exceeding the current limit in Rule 4.11.1(h) but, to the Secretariat's knowledge, the capacity of these facilities was not de-rated.

Rule Change RC_2013_09[28] notes that the (then) IMO wanted more discretion to partially de-rate capacity (to say 50 per cent). However, the Secretariat considers that partial derating still encourages old inefficient plants, that are notionally available but of limited practical value, to remain in the system.

Instead the Secretariat recommends that AEMO's discretion under Rule 4.11.1(h) should be removed and that it be obligated to de-rate capacity if that capacity does not perform to the specified availability performance.

Additionally, under the proposed arrangements there is still some risk that generators could schedule planned outages during a period of capacity shortage, perhaps in a coordinated fashion, and not incur capacity refunds. Depending on the type and quantity of generation each participant owns, such actions could increase the Balancing Price.

In order to avoid this potential problem, the Secretariat recommends that the criteria in the Market Rules governing how System Management schedules outages be changed to allow it to take into account the potential impact on the Balancing Price. This may require System Management to have some visibility of offer prices.

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25 Ibid., p44.

26 AEMO, Final Rule Change Report, Title: Incentives to Improve Availability of Scheduled Generators, RC_2013_09, Standard Rule Change Process, 31 March 2014, p6, http://wa.aemo.com.au/docs/default-source/rules/rule-change/RC_2013_09/rc_2013_09-final-rule-change-report.pdf?sfvrsn=0 .

27 Economic Regulation Authority, *2012 Wholesale Electricity Market Report for the Minister for Energy*, April 2013, http://www.erawa.com.au/cproot/11455/2/2012%20WEM%20Report%20to%20the%20Minister%20for%20Energy.pdf , pp86-87.

28 AEMO, op. cit., p3.

In addition, System Management should not allow any additional planned outages (except in emergency situations) when a trading interval is identified where spare capacity is forecast to be below the 750 MW threshold proposed in Rule Change 2013_20[29].

Refunds Recycling

The Secretariat understands refunds recycling as detailed in the Position Paper and Rule Change RC_2013_20[30] as:

- capacity refunds, which are currently distributed to Market Customers, are to be distributed amongst capacity providers; and
- this redistribution is to be based on availability and conditional upon having generated during a 30-day qualification period.

The Secretariat has several concerns with the proposed refunds recycling model and submits that refunds recycling should not be introduced.[31] Improved generator availability can be achieved through other reforms such as dynamic refunds, restricting planned outages through reform to Rule 4.11.1(h) (above) and tightening technical specifications for capacity accreditation (below).

The Secretariat understands the rationale behind refunds recycling as outlined in Rule Change RC_2013_20 to be:

- that customers receive the reliability services they have paid for even if substantial outages occur;
- it improves incentives for reliability by reallocating refunds to generators who are online; and
- it compensates generators for the MRCP not including any refund allowance[32].

Regarding the first point, the Secretariat notes that although customers have received reliability services under the current system, there is no guarantee that they will receive such reliability services at all times in the future. The Position Paper is silent on what might happen if load (above DSM) needed to be shed due to a shortage of capacity. The Secretariat also notes that, under dynamic refunds, large amounts of revenue will likely be generated during scarcity intervals, which is when market customers are at greatest risk of not receiving the reliability service that they have paid for.

Secondly, the incentives to improve reliability from dynamic refunds might not be as strong as suggested in Rule Change RC_2013_20. This is because the revenue that a generator would expect to receive in recycled refunds depends not only upon its own reliability, but on its expectation of the reliability of other generators in the market.

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[29] AEMO, Final Rule Change Report: Changes to the Reserve Capacity Price and the Dynamic Reserve Capacity Refund Regime (RC_2013_20), Standard Rule Change Process, 15 April 2015, p12, http://wa.aemo.com.au/docs/default-source/rules/rule-change/rc_2013_20-final-rc-report-and-appendices---final.pdf?sfvrsn=0 . This is the threshold below which the maximum capacity refund is proposed to apply.

[30] Ibid., pp12-13.

[31] Despite the Secretariat's concerns with refunds recycling, it notes that PJM has recently introduced this measure. Source: PJM, *Capacity Performance Settlements Impacts*, http://www.pjm.com/~/media/committees-groups/subcommittees/mss/20150217/20150217-item-04-capacity-performance-settlements-impacts.ashx .

[32] AEMO, op. cit., p10.

If the generator is profit maximising, the cost of the last unit of reliability (e.g. extra maintenance) will equal the benefit (reduced forced refunds). The first round effect of refunds recycling is that the generator has a greater incentive to incur costs to improve its reliability, as it will receive not only the benefit from not paying capacity refunds, but also the benefit of receiving a share of refunds that are paid by other generators.

However, if the generator anticipates that other generators will improve their reliability in response to refund recycling, its expectation of the pool of refunds for recycling will fall and the benefits of improving its reliability will diminish. This will reduce the amount worth investing on improving its own reliability. Its competitors will follow a similar pattern. The exact outcome will depend on the potential reliability from expenditure on each plant. The Secretariat recommends that the EMR examine these second-round effects before deciding to implement refunds recycling.

Thirdly, there is no reason why a benchmark forced capacity refund allowance could not be built into the MRCP/BRCP, reflecting that even the most reliable generator will have a forced refund occasionally. In particular:

- Rule Change RC_2013_20 considers the difficulty in allowing an ‘estimated allowance’ for capacity refunds into the MRCP/BRCP so that “the Capacity Cost Refund revenue paid to Market Customers is linked to the value of a Capacity Credit they have paid for”[33];

- However, calculation of a benchmark allowance, that the new entrant MRCP generator could not avoid, would not be difficult. It would also give generators an incentive to improve their reliability relative to the benchmark.

Rule Change RC_2013_20 also proposes to redistribute refunds to facilities “that have generated a non-zero MW value in any one Trading Interval in the previous 30-day period”[34]. It notes this is to improve the incentives for facilities to be available.

However, the Secretariat considers that this is likely to result in inefficient generation and little impact on true availability. Generators who are not available under the current system could simply generate for the minimum time possible to meet the eligibility criteria, rather than become available on an ongoing basis.

Technical Parameters for Capacity Accreditation

The Secretariat notes that there is no requirement under the WEM’s current capacity accreditation criteria for a generator to be ‘practically available’ during a trading interval with a capacity shortage.

To illustrate this situation, consider a scenario in which a potential trading interval with less than 750 MW of excess capacity is identified 24 hours in advance. For a generator that is not currently operating to be useful in such a circumstance, it needs not only to be available as currently defined under the Market Rules, but also be able to start up from its current state in less than 24 hours.

In the absence of reforms to capacity accreditation, a generator could retain an old coal plant that is rarely dispatched. Such a power station would be notionally available and would still receive capacity payments, even though it would often potentially be practically unavailable due to the plant’s long cold start-up time.

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[33] Ibid., p10.

[34] Ibid., p15.

The Secretariat proposes reforms to the WEM's capacity accreditation so that technical specifications are modified to require ramp rates and start-up times[35] that ensure generators are practically available as well as merely 'not-on-outage'. The requirements should also include demonstrated access to fuel under system peak load conditions.

The Secretariat notes the recent tightening of technical specifications in the PJM market in response to many generators not being practically available during the 2014 'polar vortex' weather event'.[36]

Market Power

The Secretariat notes the significant potential for misuse of market power under the proposed transitional and final reforms where the market capacity price is designed to escalate rapidly in response to a fall in supply. The Secretariat supports compulsory participation of known capacity in auction/transition offers, and regulatory oversight of capacity offers as necessary as suggested in the Position Paper. These arrangements will counter the potential misuse of market power by both generators and customers.

The Secretariat considers that it will be just as important to apply measures to mitigate market power during the transition period and when an auction occurs. The behaviour of Synergy[37] and other capacity holders in the WEM will need to be closely monitored during the transition period.

The Secretariat understands that there is some concern amongst merchant generators that Synergy could strategically retain generation capacity (that would otherwise be retired) until merchant generators with tighter financing constraints than Synergy leave the market, with the purpose of subsequently obtaining a higher capacity price. This may be an economic decision related to market power or a non-economic decision, perhaps based on political considerations.

The Secretariat does not know whether this is a viable strategy for Synergy or whether Synergy would pursue this strategy if it was. Nevertheless, tightening technical requirements for capacity accreditation (as suggested above) should reduce the returns to Synergy from keeping uneconomic capacity in the market in both the short and long term.

The Secretariat recommends that the EMR consider further ways to restrict Synergy from making market-power related or uneconomic decisions during the transition period.

As a last resort, the EMR might consider a form of displacement mechanism where Synergy is forced to retire capacity. However, the Secretariat considers that this should be a last resort as it does not know whether any of Synergy's capacity should be retired or not. Ideally market signals should lead to the least efficient plant retiring, rather than this being determined centrally.

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35 If a power station is already operating, then its start-up time is not relevant and its only restrictions are its ramp rate.

36 The PJM reforms include requirements for fuel contracts during peak times and start up restrictions, including requiring cold start times of 5-10 hours for coal units. Source: PJM, *Minimum Operating Parameters Under Capacity Performance*, http://www.pjm.com/~/media/committees-groups/committees/elc/postings/20150612-june-2015-capacity-performance-parameter-limitations-informational-posting.ashx

37 The Secretariat is reluctant to single out the actions of a single generator given that the new system needs to work regardless of the actions of any market participant. However, the sheer size of Synergy's generation fleet, contracted capacity and retail market share mean that its individual actions in response to market reforms could determine the success of the reforms.

TRANSITION PERIOD

Sovereign Risk

The prospect of unexpected rule changes increases the risks, and therefore costs, associated with investing in new generation. In future, generators may apply a greater risk premium to investments and refinancing arrangements, to reflect an expectation of sovereign risk, because they did not envisage the rule changes currently proposed.

The Secretariat considers that investors in generation should envisage some degree of rule changes in the future given the inherent uncertainty associated with the effectiveness of the design of electricity markets.

However, investors should also have confidence that the current and future reform process will be fair and unbiased and involve open and transparent consultation.

In this regard, investors should have confidence that the financial risks, which arise due to Synergy's market share and ownership by government, are mitigated during the transition period and once auctions commence, by implementing the market power measures referred to above.

Time until Auction

The Secretariat understands the Position Paper forecasts that a capacity auction would not be triggered until beyond 2025 when excess capacity levels are projected to be around 5 per cent in that capacity year. The Secretariat notes that:

- the forecast of excess capacity in the capacity year 1 October 2019 to 1 October 2020 in the Position Paper is 19 per cent. The capacity auction clearing price would be zero if an auction were conducted for 2019/20 under the proposed arrangements;

- it is anticipated in the Position Paper that, if 500 MW to 600 MW of generation capacity was retired an auction could be conducted in 2019 or even earlier in 2017 without a large price shock;[38] and

- it is proposed in the Position Paper to reduce the WEM's DSM level[39] immediately through the capacity baseline adjustment methodology. It is also proposed in the Position Paper to reduce the capacity price paid to DSM participants to the estimated value provided by DSM to the system, with an allowance for capacity certification costs.

The Secretariat notes that the transitional price is likely to be higher than suggested in Table 7.1 of the Position Paper. If DSM largely exits the system, through the immediate 220 MW reduction from changes to the DSM capacity baseline adjustment (and potentially more due to low returns), the market oversupply could be reduced to 15%. The Secretariat also notes that the current MRCP for 2017/18 ($164,800) is higher than the $150,000 used in Table 7.1 of the Position Paper. A 15% oversupply and a MRCP of $164,800 would lead to a capacity price of approximately $100,000 per MW per annum.

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[38] PUO, op. cit., p13.

[39] This is estimated to be 220 MW from its current level at 550 MW. Source: PUO, op. cit., p14.

The Secretariat is concerned that, at such a price, some market participants (for example Synergy) may not retire ageing and inefficient generation plant/s which would otherwise bring forward a competitive market auction either in 2019 or 2017, as the benefits to it from retaining the plant might be greater than the costs.

This could occur if Synergy owns generators whose capital costs are largely or wholly sunk and have moderate fixed maintenance costs. In the short-term Synergy might have the incentive to retire plant and raise the transitional capacity price (subject to market power restrictions).

However, in doing so Synergy could trigger an auction. This would likely see DSM re-enter the main capacity mechanism and potentially drive the capacity price lower than if an auction did not occur (see Removing DSM from the Auction above). Therefore, Synergy might be better off keeping the old plant in the system and avoiding an auction.

Overall, the Secretariat is concerned that there may not be an auction until 2025 or later. By this time the final auction design might be redundant, noting that North American capacity markets designs have changed dramatically over the past decade, and excess capacity could persist indefinitely in the market.

To offset any incentives for market participants to delay an auction, the Secretariat proposes that:

- a proposed date for the first Capacity Auction be set;
  - the first Capacity Auction be held sometime before October 2019; and
  - the auction clearing price and quantities be available for the delivery period 1 October 2022 to 1 October 2023.

The Secretariat notes that there are six full Capacity Cycles during the period 1 October 2016 to 1 October 2022 for market participants to transition to a Capacity Cycle stemming from an auction in 2019. The proposed transitional arrangements should apply during these six full capacity cycles.

Value of DSM during Transition Period

The Secretariat notes that DSM might be paid twice for dispatch up to the expected annual dispatch in Table 7.2 of the Position Paper (3.9 Megawatt hours, **MWh**[40]). The Secretariat understands the proposed arrangements as:

- DSM is paid a capacity payment based on a pro-rata of expected dispatch of 0.007 MWh per MW per annum[41]; and
- individual providers are compensated at the NEM price cap (VOLL) if they are dispatched greater than their individual production allocation[42].

The Secretariat notes that, if 1MWh of DSM is required, it is unlikely the System operator will dispatch all providers for 0.007 MWh in turn. More likely it will dispatch (say) one provider for

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[40] PUO, op. cit., p50.

[41] This is calculated by dividing 3.9 MWh by 550 MW. Data are taken from POU, op. cit., pp49-51.

[42] Ibid., p49.

1 MWh, which means the market will pay for 3.9 MWh in capacity payments plus an additional 0.993 MWh to the dispatched provider, even though only 1 MWh has been dispatched.[43]

The Secretariat recommends that:

- the first capacity auction/DSM procurement be held before October 2019 as recommended above to determine the amount of DSM required by the market; and
- DSM providers are paid a capacity price equal to their capacity testing costs (1 MWh at VOLL per MW per annum), and are compensated for dispatch when they are dispatched. These payments would be the provider's MWh dispatched multiplied by VOLL.

[43] If 3.9 MWh of DSM was dispatched from one provider in 2016/17, DSM payments would be paid to 3.9 MWh plus 3.873 MWh.

DSM HARMONISATION

The Secretariat supports the recommendations in the Position Paper to implement the measures proposed by the IMO to harmonise the requirements for availability of DSM with other forms of generation capacity.

The Secretariat acknowledges that there are considerable challenges to integrating DSM into an energy/capacity market, meaning that some level of simplification is required in defining DSM products. This simplification is likely to mean that the practical value of DSM to the market will be less than its potential or theoretical value.

The Secretariat agrees that a crucial part of DSM reform is to set a capacity baseline that allows providers to dispatch over the daily period proposed in the position paper (12 hours), and understands that this is behind the choice stated in the Position Paper of the 5th percentile of a provider's top 200 hours.

However, the Secretariat notes that this excludes potential demand reduction at potentially high demand times (depending on whether the provider's load mirrors system load). The Secretariat considers that a second DSM product (**DSM2**) could be included that had a lower availability constraint but higher capacity baseline.

Capacity payments[44] for DSM2 would be lower than normal DSM and capacity reflecting the lower daily availability requirement, but this would be partially offset if dispatched during peak (higher price) periods. The Secretariat acknowledges that registering a second DSM product would be at the cost of simplicity, but could provide considerable value to the market.

The Secretariat notes that DSM harmonisation still important even if its proposal to exclude DSM from the capacity auction were to be adopted. This is because the total of traditional generation and DSM must add to at least the RCR, and standardisation of DSM is required for this calculation.

[44] This is if DSM was paid a capacity payment and was included in the capacity auction. DSM at whatever time of day would simply receive VOLL whenever dispatched under the ERA Secretariat's proposed model.