Perth Energy Submission in response to Draft Recommendation Report entitled "Improving Reserve Capacity pricing signals – a proposed capacity pricing model"

Introduction

Perth Energy welcomes this Draft Report and is pleased to be able to provide this response. As the owner of one of the few genuinely independent power stations, one that is an almost perfect match for the "Benchmark" power station, and as a significant retailer, we are well positioned to assess the likely outcomes of these capacity proposals. In a nutshell we consider that this Draft Report contains some sound ideas but it has shortcomings which could lead to unintended consequences that may cause harm to customers and market participants.

The report takes an economically pure approach that sets capacity prices based on the value of reliability to customers. This produces extreme price volatility that places unacceptable risks onto generators and pushes price uncertainty onto customers. This is partially addressed through setting price bands for existing generators but comes at the cost of losing the single capacity price which has been one of the foundation features of the mechanism to date. Perth Energy sees this high level of uncertainty as one of the major problems with the Reserve Capacity Mechanism (RCM) rather than being part of the solution.

The Draft Report is silent on how the new multiple prices are to be translated into a price that can be passed through to end-use customers. Given that this is a pass-through for many customers a full explanation of the new process is essential before Perth Energy could endorse the proposals.

Background

The RCM was welcomed by investors and financiers as providing implicit backing to support generation investment. It was seen by Government and the then Independent Market Operator as ensuring that adequate generation capacity would be provided to prevent a recurrence of the rolling blackouts that had, just prior to its introduction, caused social disruption and economic damage. A single reserve capacity price ensured that trading was simple and Market Rules around payments and refunds couple be kept simple.

During the early years of the WEM, demand was forecast to rise substantially and the RCM successfully brought new capacity to the market. Forecast demand grew so rapidly that the Supplementary Reserve Capacity process was invoked and a substantial quantity of demand side management (DSM) was contracted but never invoked. Since then, however, a combination of significant reductions in load forecasts plus Government policies has meant that no further capacity has been brought on line as a result solely of the RCM.

Low growth, substantial investment in renewable generation (both in front of and behind the meter) plus a surge in DSM saw the development of substantial excess capacity. This was perceived as imposing

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unnecessary additional costs on customers leading to steps to drive excess capacity from the market. These actions were only partially successful. The quantity of DSM was drastically cut by imposing much tighter certification requirements and some older generating plant was removed following a direct order from the Minister.

Despite the fairly brutal "Lantau" mechanism, no aging generators responded to it by leaving the market. However, it has also led to the spectre of very low, or even zero, prices which has killed the prospects of new dispatchable generation. While this is not an issue when new renewable plant is being encouraged onto the grid by likely energy sales and Government support, it means that the RCM needs significant change if a potential shortfall arises.

PE Response to the Report

The Draft Report states that

> *…as the market is shifting from a prolonged period of excess capacity to a tighter supply-demand balance, going forward, there is a need not only for capacity investments, but that these investments be in the types of capacity that is required by the market*.

Perth Energy's fully agrees with this premise and our comments are focused on answering three questions:

1. Do the proposed changes encourage timely investment in new capacity?
2. Do the proposed changes encourage the required types of capacity?
3. Do the proposed changes encourage excess capacity to leave the market?

Before attempting to answer these questions, it is crucial that the distinction between capacity and ancillary services is acknowledged.

Distinction between capacity and ancillary services

Section 2.1.1 defines what capacity is and states that

> *…capacity is a source of power system adequacy such that sufficient resources exist at any point in time to meet electricity demand if called upon to do so. Capacity resources are remunerated for being present in the electricity system, regardless of whether they are dispatched.*

Perth Energy concurs with this.

In its discussion of the missing money the Draft Report notes that the ancillary service markets, including through contract arrangements, is a potential source of revenue for capacity providers. Perth Energy agrees and notes that a number of ancillary services will be of a fixed or capital nature that would, like reliability obligations, best be paid through some form of fixed payment. Examples of these services could include:

- Fast start capability;
- Fast load following capability;

- Repetitive cycling (start-run-stop) capability
- Capability to provide spinning reserve;
- Fault ride through capability;
- Rotational inertia; and
- Actual location.

These capabilities would generally need to be designed into the generator prior to construction which is why they are referred to as “capital” type services.

We have recently seen the outcome of paying just for capacity with the planned closure and then non-closure of Synergy’s Mungarra and West Kalgoorlie gas turbines. If the value of transmission support had been correctly priced into the revenue that Synergy was receiving for these plants, rather than just a standard capacity payment, a quite different outcome could well have eventuated.

In its earlier submission Perth Energy noted that these services should be integrated with the RCM payments. So we welcome the commitment by the PUO to include the power system security work stream as a key element of the reform program. It is this work that needs to identify both ancillary services and reliability obligations, quantify what is needed and establish a mechanism for payment.

Question 1: Do the proposed changes encourage timely investment in new capacity?

So it is probable that the proposed changes will deliver DSM capacity to the market (in a timely manner). While it is suggested that a 25% continuing security deposit should place a cap on new DSM the potential financial gains will easily cover the cost of financing this security. The actual amount of DSM likely to re-enter the market is unpredictable but something close to the 500 or so MW that we saw a few years ago is quite likely. Perth Energy questions the rationale of bringing back DSM and reward them as much as a generator.

The RCM is not the driver of renewable energy generation. Federal Government policy has subsidised the development of substantial quantities of renewable energy generation both ahead of and behind the meter through the Renewable Energy Target.

The Draft Report proposes that new capacity be allowed to nominate a five year price guarantee. It is PE’s opinion based on advice from our financier that this is far too short a period and that a minimum of 10, preferably 15 years would be required in this market. The earlier PUO discussion paper gave examples of overseas capacity markets that provide guarantees much longer than five years and it would be interesting to know why this short period was considered appropriate.

When the WEM is facing the need for new dispatchable generation capacity to provide fast response supply and other ancillary services to support renewables, the structure proposed in the Draft Report cannot deliver. The Draft Report is an attempt to address the issues but the proposals fall seriously short and will not provide any investor the certainty required to construct plant.

Question 2: Do the proposed changes encourage the required types of capacity?

The answer to the question as to whether the proposed changes will deliver the correct mix of resources has to be “no”. Unless a value is placed on the additional services that a generator can provide then there is no incentive to build anything other than DSM to meet capacity. Generators that make substantial revenue from energy or green certificate sales will still be built but, as noted above, the RCM is not the major factor drawing these into the market.

We understand that the PUO is undertaking further modelling to identify the future plant mix in the WEM. Once these results are available it will be possible to determine whether the RCM should continue to be technology-neutral or whether it needs to target specific plant types or plant locations to ensure long term low cost stable operation. Incorporating ancillary and reliability service costs should achieve this but if the system risks moving out of balance prior to that some form of override may be required.

Question 3: Do the proposed changes encourage excess capacity to leave the market?

There has been ongoing discussion about the need to send signals for excess capacity to be encouraged to exit the market. There has, however, never been any real identification of what plants should be encouraged to leave. The Lantau curve is now so steep that Synergy would increase its capacity revenue by reducing its certified capacity and yet the only plant to be closed has been by Government directive.

Clearly either there is intervention in these decisions by Government, or the pricing signals in the RCM are inadequate, or both.

The provision of the price bands for existing generators is considered a sound move to encourage plant to remain within the WEM rather than consider relocation elsewhere. But while we support these, we consider that ongoing substantial support for aging plant is in direct conflict with the previously stated objective of encouraging older plant to exit the market. Once plant reaches the end of its project life, commonly 30 years, it should receive either lower capacity certification or a lower capacity price. If it can still be run economically then it can remain in service; if not it should be retired. Supporting old plant beyond its economic life through capacity payments is adding a major burden to customers.

Who pays for excess capacity costs?

The Draft Report claims that the level of excess capacity over the market requirement reached 23% by 2016/17 resulting in an estimated “cost” to customers of $116 million. This is a common claim but it is certainly not the full story in respect to who is paying for excess capacity.

What the report does not say is that in 2016/17 the RCP was only 70% of the benchmark reserve capacity price. So while customers were paying for substantially more capacity than they needed, the unit price of this capacity was reduced in correlation with this oversupply. If the total sum paid for capacity is determined by multiplying the RCP by the quantity purchased it appears that customers are no worse off because of the excess.

There is certainly an economic cost derived from excess capacity in the WEM and this is carried by three groups. The first group are generators who each receive lower capacity income for their plant. The income received by the Western Energy Kwinana Swift power station, for example, has been reduced by around $15 million over the period to 2019/20 (the last year that a price was set). This plant represents only a few percent of installed generation capacity which gives an indication of the overall impact on generators.

The second group to lose money is retailers who have contracted to buy capacity credits at a higher fixed price and are unable to pass the full costs to customers because of competition from other retailers (where such competition exists). Contestable customers received the benefit of the reduced RCP because any retailer who tried to recover costs at a higher rate could not compete in the market.

The third group is those customers whose retailers have bought capacity credits at a higher fixed price but are able to pass these costs through.

The Draft Report is incorrect in arguing that customers have borne the entire cost of excess investment. The majority of the cost has been borne by Investors in Generation and in Retail, and only those customers without choice have borne the balance.

Retailers and customers need price transparency and certainty

While the Draft Paper has focused on capacity providers it is silent on how reserve capacity prices are to be recovered from customers through retail prices. The RCM as it is proposed in the Draft Report will not provide clear signals on price to market participants and will in fact place a considerable burden on the retailers in the market to appropriately price capacity. As noted above, Perth Energy does not believe that retailers will be able to enter into “hedges for capacity”, as suggested by the PUO, because of the extremely volatile prices and lack of counter parties. If, however, hedges could be established this by default means that the market signal currently used for pricing of capacity no longer exists. Transparency and clarity regarding the price of capacity in the WEM will no longer be available.

The paper is silent on how this mechanism will be transacted in the market. How will AEMO clear a price to be paid to each generation plant? How will AEMO manage to balance the market if 90% of participants are receiving a floor price, and 10% a different price altogether? It is unclear how differential payments will be made by WA Treasury or by Synergy as the Government’s market participant proxy. The mechanisms required to achieve the proposals contained in the Draft Report require further detailed explanation because at this juncture the proposals contained therein are not practical for, or transparent to, end users.

Conclusion

- ***Do the proposed changes encourage timely investment in new capacity?***

  No, the proposed changes are unlikely to encourage new dispatchable plant to enter the market because of the high risk that they will be unable to make an adequate return on capital invested.

- ***Do the proposed changes encourage the required types of capacity?***

No, the proposed changes will tend to encourage DSM along with energy production plants but will, as noted above, not encourage new dispatchable plant.

- ***Do the proposed changes encourage excess capacity to leave the market?***

  No, providing a ten year price guarantee to aging plants does not encourage these units to exit the market.

From the perspective of the operator of an existing generation plant, Perth Energy welcomes the proposed price bands for existing generators. It is a recognition of the risks that have been taken on by investors and the substantial increase in risk caused by market rule changes and the encouragement of renewable energy within the WEM.

It is reassuring that the PUO has also clearly identified the issue of missing money for investors and the need to address this. However, until appropriate payment is provided for the provision of reliability obligations and ancillary services the problem will remain. This proposal is likely to result in capacity pricing sitting at the floor of $105,000 per MW per year for much of the coming 10 years, largely driven by the change of the excess capacity price curve, bringing DSM back into the market and the growth of non-dispatchable generation. The benchmark plant, which is a modest sized open cycle gas turbine like Kwinana Swift, is valued by AEMO at around $150,000 per MW per year. Clearly there is a gap between the value of the plant such as Kwinana Swift and the RCP proposed under this Draft Report.

The approach to pricing capacity is based on the value perceived by customers for reliability. This economically “pure” approach has the major downside of introducing massive price volatility which must be mitigated before prices are passed through to retail customers. The price bands, which are essential if existing plant is not to be exposed to these price extremes, remove one of the key strengths of the market to date which is having a single capacity price. This raises a number of issues on which the Draft Report is silent but only until these matters are resolved can market participants give endorsement to the proposals.

The mechanism as proposed will not encourage the right plant mix into the WEM. All capacity is treated the same with no financial consideration for location, operational obligations or ancillary services. We note that there is a Workstream looking at some of these aspects. We contend that these must be coordinated with capacity payments or the market will end up comprising only aging coal plant, renewables and DSM.

Report Assessment Detail

> ***The primary problem [with the RCM] has been a tendency towards significant over-procurement of capacity. (Page vi)***

Much of the capacity that has been introduced into the WEM has been driven by factors other than the Reserve Capacity Mechanism (RCM). The first major blocks of capacity were brought on-line through power purchase agreements with the then retail-only Synergy. The expectation at that time was that Verve, which had been an unsuccessful tendered for these PPAs, would close plant that was now excess to capacity but this did not happen. As a result there has been a continuing surplus of base load plant in service.

Further capacity has been brought into service as a direct result of the Federal Government renewable energy process with plants being funded largely by renewable energy certificates and energy. Capacity payments represent a relatively small proportion of the income of these plants.

Changes to the Market Rules to accommodate further plant through the GIA arrangement has further increased the excess capacity.

The only plants that were drawn into the market by high reserve capacity prices, and which might be considered to have contributed to the over-supply, are the diesel fuelled Merredin Energy and Tesla power stations. These plants amount to a relatively small total capacity of around 100 MW.

Changes to the Market Rules that encouraged demand side management also contributed towards the surplus though subsequent changes have driven almost all DSM out of the market.

> ***The level of excess capacity over market requirements reaching 23 per cent by 2016-17, at an estimated cost to electricity customers of around $116 million. (Page vi)***

The steep slope that relates the reduction in reserve capacity price to excess capacity means that the total payment made by customers for capacity actually falls as excess increases. When the reserve capacity price falls, even though a retailer may be purchasing capacity credits under a contract at a higher price, competition prevents this additional cost from being passed through to customers. Those retailers selling electricity who have access to the lower priced credits set the price that all retailers must meet. As a consequence, contracted retailers pay a substantial sum from investor returns towards the cost of excess capacity.

Similarly, generators have also picked up a substantial portion of the cost of excess capacity because their revenue has fallen. Perth Energy has determined that the revenue received by its Kwinana Swift power station was reduced by over $15 million over the period 2019/20 (the last year for which a price has been set).

> ***The reforms are intended to ensure that the capacity pricing model better signals the economic value to the market of incremental capacity … when it is in excess. (Page vi)***

The current pricing model, with the "Lantau" curve, sends very strong signals that plant should be removed from service. As noted in the report, closure of older Synergy plant has only occurred as the result of a direction from Government.

The proposed "price bands" will provide an income cushion for their oldest generators. This undermines the objective of encouraging excess plant to exit the market. It is unclear what the policy in regards to the current type of plant exiting the market. The proposal as it stands is likely to provide new plant more of a signal to exit than old plant nearing the end of its useful life. The impact of the steeper curves is significantly more to new plants as older plants are most likely not subject to any funding arrangements.

> ***The allocation of cost and risk between consumers and investors through the reserve capacity mechanism was also generally recognised as being deficient and this problem remains. (Page 10)***

A significant cause of the excess capacity was over estimation of demand. These forecasts are provided by AEMO, and formerly IMO, ***on behalf of customers*** to ensure that sufficient generation is provided to meet customers' desires for reliable electricity supply. It hardly seems reasonable that retailers and generators should bear the cost of over estimation of demand.

By resetting the price each year, there is a wealth transfer from private generators to customers. Consumers, via AEMO, are saying that they want additional capacity built when it appears to be needed but they then don't want to pay when they realise they have bought too much. By having a steep excess capacity curve the proposed new pricing model extends this misallocation of risk. This has been acknowledged through the proposed "price bands" for existing plant and is a positive step, but the valuation of that risk transfer has not been undertaken adequately.

> ***Transitional arrangements are proposed involving a price band for existing generation facilities between $105,000 and $130,000 per megawatt (Consumer Price Index (CPI) adjusted) for a period of ten years. (Page vii)***

Perth Energy sees this implementation of a price band as a positive move in that it recognises the substantial impact that price changes are having on existing generators. Excess capacity is largely the result of Verve Energy retaining plant in service despite losing a significant portion of its "contract" to supply base load energy to Synergy along with Federal and State Government policies to encourage renewable energy.

However Perth Energy believes that generators providing ancillary services and reliability obligations are only fairly compensated if the payments for these services are aligned with the implementation of the proposed RCM. The Draft Report has rightly identified the "missing money" and work needs to follow to identify both ancillary services and reliability obligations, quantify what is needed and establish a mechanism for payment as part of the RCM Reform.

AEMO would first award capacity credits to new floating price capacity and existing capacity providers and, if an adequate level of capacity is not achieved, then award all capacity resources that opted for a price lock in. (Page vii)

Perth Energy supports this. If new capacity is being offered by investors who are happy to receive the floating price with no guarantee then these offers should be accepted first because it is likely to result in lower prices to customers. If existing plant provides sufficient capacity Perth Energy considers that no offers should be made to any new capacity.

As the market is shifting from a prolonged period of excess capacity to a tighter supply-demand balance, going forward, there is a need not only for new capacity investments, but that these investments be in the types of capacity that is required by the market. (Page 10)

Perth Energy fully agrees with this statement. The RCM, as proposed in the Draft Report does not support this statement. It is Perth Energy's opinion that there needs to be integration between the RCM and ancillary services to send these signals because a number of potential future requirements are of a capital investment nature. For example, the provision of inertia, spinning reserve capability, fault ride-through and similar capabilities need to be built into the facility at the design stage. As Perth Energy outlined in previous papers to the PUO, the differing requirements in different geographical areas mean that the type of plant required in the future is not a "one size fits all", which in turn means that different requirements have different capital & investment profiles. The proposed arrangements do not recognise this in any way.

As Perth Energy have outlined previously, a price should be established for all "capital" type items individually and facilities paid on the basis of what they can offer the market. For example a battery may offer synthetic inertia and instant MW response plus the ability to sustain output for a short period. A generator may not be able to offer instant response but could offer six minute reserve that can be sustained for a prolonged period.

Section 2.3.1 (Page 19) notes that [R]eforms to address these deficiencies form part of a separate component of the WEM reform program, involving assessment of the types of ancillary services likely to be required in the SWIS and the form of market arrangements necessary to support delivery of these services.

Perth Energy considers that reflection of these capacity-type ancillary services must be given priority in the current work being undertaken as part of the WEM Reform Program. These prices need to be established in time for them to apply within the reserve capacity process that commences in 2020 so that appropriate incentives are in place to incentivise the different types of required new capacity entering service in October 2022. The continued growth of the "duck curve" plus the increasing age of various coal-fired generators and continuing investment in renewable projects means that these arrangements cannot be delayed without risking development of a critical plant imbalance.

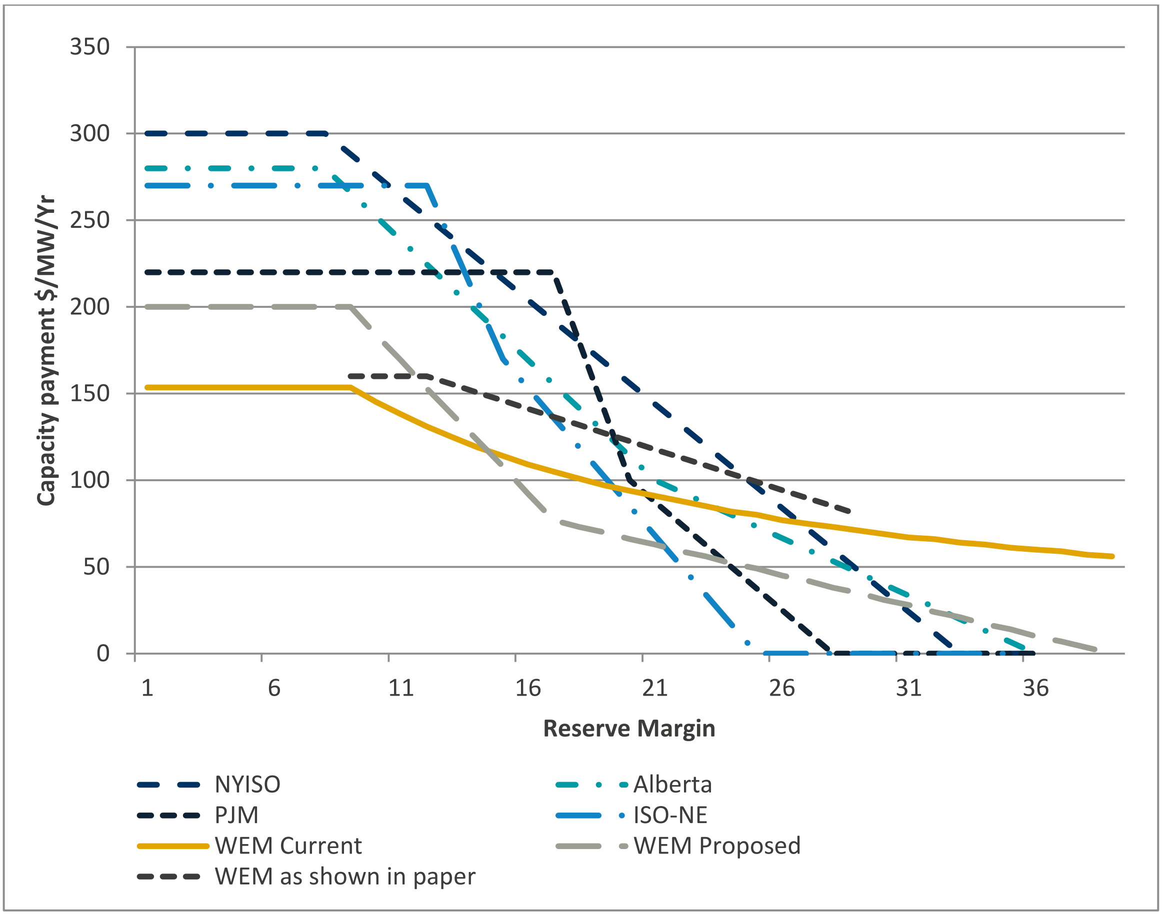
Establishing appropriate payments for these types of ancillary services would, if priced correctly, also offset the low price bands being proposed for existing generation capacity. It would also differentiate the relative value between DSM and generation.

> ***The first point to note [in discussion of Figure 3.2 on page 29] is that the prevailing capacity price curve for the WEM is less steep than for all of the other markets.***

The curve marked "Current Reserve Capacity Mechanism" in Figure 3.2, and repeated in Fig 4.4 on page 36, appears to have been displaced as it does not match the figures tabulated in table 5.2 on page 45 and the curve shown in figure 5.2 on page 44. This curve is reconstructed below using the tabulated data to compare the proposed curve with the North American curves.

The curve cannot be taken directly from the data in Table 5.2 as this is given as "Excess Capacity" whereas figure 3.2 is "Reserve Margin". So the curve has been moved to take account of the 8% reserve margin in the SWIS. It can be seen that the dollar value of capacity payments for the other markets are significantly higher than in the WEM over almost the full range of the curve. It is only when excess capacity exceeds around 23% that the WEM price matches the price in the ISO-NE.

Copy of Figure 3.2 with current and proposed lines added based on table 5.4



It appears that from correcting the graphics in the Draft Report this Proposal does not follow the features of the referenced systems.

The Draft Report points out that the slope in other markets is higher and recommends following this North American precedent. However, there is no suggestion that the higher prices, and starting point for the steep slope should also be followed. Figure 3.2 shows that the cap price applies in the PJM system until excess capacity reaches around 16%. In the other three systems the cap price holds until excess capacity reaches around 12% (ISO-NE), and 7% (NYISO and Alberta).

Taking just some of the features of these other systems but not all results in a skewed outcome that disadvantages capacity suppliers.

It should also be noted that these North American systems are vast compared to the WEM. The amount of additional plant required to create an excess is far greater than in the SWIS where chunky investment leads to significant volatility. A steep curve in the WEM will create far greater investment risk compared to a similarly steep curve in a large system

Page 39: "The PUO considers that allowing new capacity resources an option to lock in the capacity price at the time of entry, limited to a five year period, is appropriate to facilitate investment."

The earlier PUO paper "Improving Reserve Capacity Pricing signals – alternative capacity pricing options" published in April 2018 noted that capacity contracts were awarded for 15 years in the UK, 10 years in Ireland and three years in Italy. Further in France capacity certificates can be awarded for up to seven years for new entrants.

The Draft Report should clarify why such a short period of certainty is considered appropriate given the small size of the WEM and the high price volatility over recent years. On the surface this seems contrary to the situation to other markets highlighted in this Draft Report. It is unclear why the Draft Report details the features of these markets but does not propose similar features for the WEM.

Demand side management (Page 38)

Perth Energy considers that DSM has a valid role in the market. We agree that the very large quantity that was in place a few years ago was excessive but that more than currently exists could be beneficial.

The paper states that "*it is preferable that the [DSM] resources be remunerated using the same prices as other forms of capacity"*. Despite the discussion in section 2.1.1 the paper does not settle on just what is meant by "capacity" but if DSM capacity is deemed to be the same as generator capacity then this is a significant step that has implications for operation and pricing in the WEM.

DSM has a number of obligations that a significantly weaker than those on generators including:

- DSM can offer capacity for a minimum of 200 hours per year;
- DSM can offer capacity for a minimum of 12 hours per day;
- DSM is permitted a dispatch notice period of up to two hours; and
- DSM only has to be available for dispatch between 8 AM and 8 PM.

If the Draft Report proposes that fulfilling these obligations is sufficient to be defined as capacity and receive full payment, it is unclear how the additional obligations that are placed on generation capacity are to be rewarded. The additional obligations come with significant costs, which are not borne by DSM.

Examples of these obligations are generation facilities are still required to be available 365/24/7, be available for immediate dispatch, hold 14 hours of fuel or have fuel contracts up to three years in advance then they need to be compensated as ancillary services.

It should also be noted that of the $116 million of "estimated cost to customers" (page vi), $60 million was paid to DSM. Even by requesting a 25% security deposit (which is refundable), this payment level implies a 400% rate of return to DSM providers even if they are not called. Inappropriate valuations and inadequate definitions of "capacity" could result in the WEM becoming a market of old coal plants, renewable plants and DSM.

Energy Storage Technologies (Page 39)

Perth Energy agrees that there is likely to be a positive role for energy storage systems during coming years. To ensure that storage is appropriately rewarded it is critical that the value of the various services provided be correctly costed and paid for. This confirms the need for a correct definition of capacity to be developed along with definitions and prices for ancillary services.

Binding contract against exit (Page 46)

The paper rightly notes that sudden exit of generation capacity represents a significant risk and it proposes mechanisms to address this in respect to DSM and for generation facilities. Perth Energy supports the proposed approaches of:

- Requiring DSM to post a substantial security deposit; and
- Require generators to give three years notice.

It should be noted, however, where there may still be situations where a generator determines within that three year period finds that prices are uneconomic and elects to remove its plant from the system. This, however, should only occur when there is a significant excess of capacity into the future.