INDEPENDENT MARKET OPERATOR

Wholesale Electricity Market
Rule Change Proposal Submission Form

RC_2013_10 Harmonisation of Supply-Side and Demand-Side Capacity Resources

Submitted by

Name:	Ky Cao
Phone:	08 9420 0300
Fax:	08 9474 9900
Email:	k.cao@perthenergy.com.au
Organisation:	Perth Energy
Address:	Level 4, 165 Adelaide Terrace, East Perth WA 6004
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Submission

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

Background

The Independent Market Operator (IMO) operates the Wholesale Electricity Market (WEM) within the South West Interconnected System (SWIS). The WEM includes a Reserve Capacity Mechanism (RCM) to ensure adequate investment in capacity in the system to handle forecast peak demand scenarios and contingency events such as losing the largest single unit on the system.

Generators and demand side providers can apply to the IMO for Certified Reserve Capacity (CRC). Conventional generators will in general be eligible for CRC at a level equivalent to the output that can be achieved on a 41 degree day. Demand side providers, often referred to as Demand Side Management or DSM, are awarded CRC according to their actual demand during peak intervals in the previous Hot Season (December to March), being an indication of the amount of MW reduction in demand they may be able to deliver if called upon.

Market Customers (retailers) have an obligation to purchase and surrender CRC in proportion to their portfolio's load during the previous Hot Season's 12 peak Trading Intervals. Market Customers can satisfy this obligation by purchasing CRC bilaterally from generators and demand side providers or directly from the IMO at the default administered price. Providers of CRC can also elect to either sell their CRC bilaterally or via the default mechanism to the IMO at the administered price.

The Reserve Capacity Mechanism Working Group (RCMWG) has assessed the findings of the Lantau Group's report entitled "Review of RCM: Issues and Recommendations". Based on those findings and further assistance from the Sapere Research Group the RCMWG identified a number of issues in relation to the operation of the RCM and in particular in relation to the difference in treatment of supply-side and demand-side providers of CRC. These issues are highlighted in the section below.

Issues

Seven high level issues have been identified in relation to the criteria applying to providers of CRC as follows:

1. **Fuel requirements for generators:** Scheduled Generators are currently required to maintain a minimum of 14 hours of continuous, uninterrupted fuel supplies to qualify for CRC. There is no similar requirement on demand side suppliers to for example ensure fuel supplies to backup generators at demand side locations if these generators were to play a part in delivering any demand reductions.

2. **DSM availability requirements:** Scheduled Generators must make their CRC available to the WEM either by dispatching of bilateral contracts or by making capacity available through the Short Term Energy Market (STEM). CRC must be made available in every Trading Interval throughout the year, except when the Scheduled Generator is on outage. The availability requirements on DSM providers of CRC are more lenient and allow for as little as 24 hours of total availability during a one year period. There are also other concessions compared to the requirements on Scheduled Generators such as limits on the length of single periods of dispatch of DSM providers.

3. **DSM telemetry:** The output of all Scheduled Generators in the SWIS is monitored in real time by System Management via SCADA. System Management is therefore able to monitor the status of CRC available from Scheduled Generators. DSM providers are not required to have any similar real time monitoring in place and System Management therefore does not have the same level of visibility in relation to the potential real time capability of DSM Facilities to provide capacity support to the SWIS when needed.

4. **The 3 Day Rule:** Currently, DSM providers are relieved from any obligations to provide capacity to the system on a third day if they have already been called and provided capacity (by reducing demand) on two consecutive days. There is no similar relief for Scheduled Generators who must make their capacity available at all times unless on outage.

5. **Non-Balancing Dispatch Order:** DSM providers are included in the Non-Balancing Dispatch Order (NBDO). The NBDO is sorted in priority from the cheapest to the most expensive bid to reduce demand. In the event of a tie on price, the current Market Rules

calls for the largest volume DSM provider to be called ahead of smaller ones. This may provide a dis-incentive to aggregate loads into larger DSM programmes.

6. **Dispatch outside of availability limits:** Clause 7.6.10(b) of the Market Rules can be construed to prevent System Management from asking a DSM provider to provide capacity outside of the availability limits that it has nominated even on a best efforts basis.

7. **Relationship between IRCR and Relevant Demand:** Market Customers' obligation to purchase CRC is determined with reference to their customers' demand during the 12 peak Trading Intervals during the previous Hot Season. The result is referred to as the Individual Reserve Capacity Requirement (IRCR). No adjustments are made to this calculation to for example account for maintenance outages for loads within the retailer's portfolio.

   CRC awarded to DSM providers is based on a similar calculation for the 32 peak Trading Intervals and makes use of the concept Relevant Demand (RD), which is the median demand in MW for the DSM programme's loads during those 32 peak Trading Intervals. However, unlike the IRCR calculation, when determining the RD (and hence the level of CRC to be awarded) outages at participating load sites are explicitly taken into account and the value of the RD is brought back to the level it would have been at had the outages not occurred.

   This differing treatment of outages in the IRCR calculation and in the RD calculation places an incentive on DSM providers to schedule maintenance during the Trading Intervals that are likely to be included in the IRCR and RD Trading Intervals. Demand side providers of CRC are to some extent able to "double dip" with the current rules and reduce their IRCR liability without impacting their CRC eligibility by scheduling maintenance for facilities included in their DSM programme during Trading Intervals that are likely to fall within the IRCR Trading Intervals.

Change Proposal

The IMO submitted Rule Change Proposal 2013 10 "Harmonisation of Supply-Side and Demand-Side Capacity Resources" on 21 August 2013. The IMO proposed the following amendments to the Market Rules in relation to the seven issues identified above:

1. **Fuel requirements for generators:** The IMO has proposed to remove the requirement on Scheduled Generators to have a minimum of 14 hours of uninterrupted fuel available. The RCMWG and Sapere Research Group considered that there are sufficient commercial incentives on Scheduled Generators to have adequate fuel arrangements in place and that it is therefore not necessary to prescribe the 14 hour minimum requirement in the Market Rules. Removing the requirement would also more closely align the treatment of demand-side and supply-side CRC providers in this respect.

2. **DSM availability requirements:** The IMO has proposed a number of changes to the minimum availability requirements for DSM providers as follows:

Requirement	Current Rule	New Rule
Days of availability	All Business Days (subject to total dispatch events)	All Business Days
Dispatch events per year	At least 6	All Business Days (about 250)
Hours per day	4	6
Total hours of dispatch per year	24	Only limited by the hours per day and days of availability criteria. A maximum of about 1,500 hours per year (250 days by 6 hours)
Earliest start	12:00PM	10:00AM
Latest finish	8:00PM	8:00PM
Minimum notice period	4 hours	2 hours

In general, the proposed changes would significantly increase the dispatch availability requirements on DSM providers and more closely align these requirements with the requirements on Scheduled Generators.

As a consequence of the proposed changes in the table above there are also some flow on effects on the capacity refund calculations, the Availability Classes and therefore also the Reserve Capacity Auction design.

Capacity Credit Refunds for DSM providers that fail to deliver when called upon are currently made to pay a refund in proportion to their total annual availability. For example, a DSM provider that is only registered to provide up to a total of 24 hours of DSM response, and is dispatched for 1 hour and fails to respond, will currently be liable for refunding 1/24th of the annual value of its capacity credit payments.

With the proposed new requirement for all DSM providers to be available at least 6 hours per Business Day, the IMO has proposed to amend the capacity credit refund payment formula for DSM providers so that it links to the proportion of the daily availability requirement that was not delivered.

The number of Availability Classes will be reduced from the current four to only two. Availability Class 1 will continue to be for all Scheduled Generators and others that elect to be available in all Trading Intervals (this may include DSM providers). Availability Class 2 will be for all other Facilities.

The Reserve Capacity Auction design will under the proposed amendments be simplified by now only iterating the process through the two remaining Availability Classes.

Finally, the IMO has also proposed to introduce a new requirement on System Management in clause 7.11.5(j) to provide Market Participants with a Dispatch Advisory when System Management expects to issue a Dispatch Instruction to a Demand Side Programme in the next 24 hours.

3. **DSM telemetry:** The IMO has proposed that all DSM providers be required to have in place telemetry to enable real time flow of data to System Management. These changes will take effect from year one of the 2014 Reserve Capacity Cycle, with all physical and

procedural changes in place for go live on 1 October 2016. There will be a need to develop necessary details around the procedures around System Management's B2B systems to support the proposed telemetry solution. The IMO has also proposed to amend clause 7.10.4 to remove the current exclusion of DSM providers in System Management's monitoring obligations of Dispatch Instructions.

4. **The 3 Day Rule:** The IMO has proposed to remove the current relief from providing capacity on a third consecutive day for DSM providers.

5. **Non-Balancing Dispatch Order:** The IMO has proposed to amend the tie-breaker rules in the NBDO so that Facilities are ranked according to the amount of time since they were last dispatched (those with the longest time since last dispatch to rank ahead of those with less time) without regard to the size of the DSM programme.

6. **Dispatch outside of availability limits:** The IMO has proposed to amend clause 7.6.10 so that System Management is allowed to Dispatch DSM programmes outside of their availability criteria. Such dispatch will be on a best efforts basis and no formal obligation to provide capacity will apply. A DSM programme that fails to comply despite best efforts will therefore not be subject to any capacity credit refund payments.

7. **Relationship between IRCR and Relevant Demand:** The IMO has proposed to amend the calculation of RD so that a DSM programme cannot sell more capacity than it is liable to buy via the IRCR associated with the loads in the DSM programme.

Perth Energy's Views

Perth Energy supports the proposed amendments to the Market Rules as they in our view represent a significant improvement on the current status quo.

However, with the proposed amendments there will continue to be two very different Availability Classes for capacity providers with different obligations attached to delivery of what should be a homogenous product (capacity). Perth Energy questions the value for money and reliability attached to capacity provided by demand side measures compared to conventional capacity provided by Scheduled Generators. Ultimately, it is end users in the SWIS that will be burdened by additional costs and reliability issues flowing from continuing to have an unnecessary and inefficient system where some capacity has more lenient performance obligations attached without this being reflected in a reduced price for that capacity.

Perth Energy urges the IMO to conduct a further review of this part of the Market Rules as soon as possible to remove the remaining differences in treatment of capacity across the system. The review should include the option of removing DSM providers from the capacity mechanism altogether and instead developing a specific ancillary service product for DSM providers to complement capacity and/or energy requirements in the SWIS.

Perth Energy agrees with the proposal to remove the requirement to have 14 hours of uninterrupted fuel available for Scheduled Generators as there are other commercial and risk based incentives that support provision of adequate fuel supply. The IMO may wish to consider whether there may be value in having some generators (a system safety net) maintaining verifiable, uninterrupted fuel supplies, for example via a dual fuel set up. This could be set up as an ancillary service to improve reliable operation of the SWIS in a situation similar to the 2008 Varanus Island incident.

With respect to the proposed updates to DSM availability criteria, Perth Energy supports these changes as being steps in the right direction. Ideally, Perth Energy would like to see similar conditions as those that apply to Availability Class 1 applied to DSM providers to further reduce any discrepancies in the delivery of capacity from generators compared to demand side providers.

Perth Energy agrees with the proposed amendment to the Market Rules to compel System Management to issue Dispatch Advisories to DSM providers 24 hours before a likely dispatch event. However, if System Management, for whatever reason, failed to issue a Dispatch Advisory this should not detract from the DSM provider’s obligation to comply with a Dispatch Instruction from System Management to reduce load. Perth Energy would welcome clarification from the IMO in relation to this point.

Perth Energy welcomes the roll-out of telemetry to DSM providers. This will provide System Management with much better tools in real time to understand the availability of capacity from demand side providers. Perth Energy notes that there is a requirement to amend certain Market Procedures to enable this change. We would welcome consultation on any such amendments as soon as possible so that Market Participants can get certainty around the new arrangements to allow them to develop any necessary changes to internal procedures and systems.

With respect to the proposed changes around the three day rule and dispatch outside of availability limits Perth Energy supports all the proposed amendments as they will more closely align the requirements on DSM providers with capacity providers in Availability Class 1. Ultimately, we would like to see the same obligations applied to DSM providers of capacity as those that apply to Scheduled Generators in Availability Class 1.

Perth Energy also supports the proposed amendments to the tie breaker rules in the NBDO to remove the current dis-incentive on aggregating into large DSM programmes. However, in line with our comments above to further harmonise the treatment of all capacity providers we would like to see DSM programmes included in the normal Balancing Merit Order with all other providers of capacity.

Finally, Perth Energy also agrees that the proposed amendments around the calculation of RD for a DSM provider so that no DSM provider can be awarded more capacity than the sum of the IRCR requirements of the loads that make up the DSM programme represents an improvement on the status quo. However, we question the rationale for using the sum of the IRCR requirement of each individual load within the DSM programme as the constraint in the calculation. The IRCR of an individual load does not in general reflect the amount of demand reduction the load is capable of and therefore the upper limit on the amount of capacity that should be awarded for that load. This is because the IRCR of a load is made up of the following generic components:

IRCR = Median MW load during IRCR intervals x specific uplift factor[1] x total uplift factor.

[1] There are different specific uplift factors for temperature dependent loads and non-temperature dependent loads.

The uplift factors provide the conduit to allocate additional capacity to loads above and beyond the absolute contribution that the loads made to the system peak. This is necessary to ensure that additional capacity that is required to satisfy the planning criteria (e.g. to meet the 1/10 year peak demand on the system and do so even with the loss of units on the system) is allocated to and paid for by Market Customers. Using the temperature dependent load and total uplift factors published on the IMO's website for October 2013, a load that had a 1MW median read for the IRCR intervals would have an IRCR requirement of 1MW x 1.5925 x 0.9974 = 1.5884MW.

Perth Energy suggests that in the example above, the maximum capacity awarded should be 1MW, which represents the actual ability to reduce demand. The higher value represented by the IRCR value is artificially inflated by the uplift factors and that amount of demand reduction is unlikely to be available from the load.

Perth Energy proposes to remove the effect of the uplift factors by amending the drafting of clause 4.26.2CA(b). The clause should refer to the "individual median MW Metered Demand during the IRCR intervals" of the Associated Loads in the Demand Side Programme instead of the "Individual Reserve Capacity Requirement Contributions". It will also be necessary to replace the definition of "Individual Reserve Capacity Requirement Contribution" with an appropriate definition of "Individual Median MW Metered Demand during the IRCR Intervals" and amendments to the proposed new step 11 in Appendix 5.

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

Subject to our comments above, Perth Energy considers that the proposed amendments to the Market Rules would positively impact on the ability to achieve Market Objectives (a), (b), (c) and (d)[2] for the following reasons:

Market Objective (a) which relates to the efficient and safe production and supply of electricity would be positively impacted by a number of efficiency related improvements including removing the unnecessary mandated requirement on Scheduled Generators to maintain 14 hours of uninterrupted fuel supplies, more closely aligning the availability requirements on DSM providers with those that apply to Scheduled Generators, resulting in more efficient use of available capacity and better value for money for SWIS end users in relation to capacity from DSM providers. The requirement for telemetry on DSM providers will also improve efficiency of dispatch and utilisation of these capacity providers.

[2] The objectives of the market are:
(a) to promote the economically efficient, safe and reliable production and supply of electricity and electricity related services in the South West interconnected system;
(b) to encourage competition among generators and retailers in the South West interconnected system, including by facilitating efficient entry of new competitors;
(c) to avoid discrimination in that market against particular energy options and technologies, including sustainable energy options and technologies such as those that make use of renewable resources or that reduce overall greenhouse gas emissions;
(d) to minimise the long-term cost of electricity supplied to customers from the South West interconnected system; and
(e) to encourage the taking of measures to manage the amount of electricity used and when it is used.

Market Objective (b) which relates to encouraging competition in the SWIS will be positively impacted by the fact that there will be a more equitable treatment of supply-side and demand-side capacity and thereby a levelling of the playing field.

Market Objective (c) will for the same reason be positively impacted as the levelling of the playing field will remove some inherent and unjustified differences in treatment of supply-side and demand-side providers of capacity.

Market Objective (d) should be positively impacted as the proposed amendments are likely to remove some of the current additional costs on end users relating to the inefficient over-supply of capacity. The improved incentives and rules on demand-side providers should lead to an improved mix of demand-side and supply-side providers of capacity in the longer term.

Perth Energy believes that further harmonisation of the obligations on capacity providers would further improve the ability to achieve the Market Objectives.

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.

Perth Energy has not identified any impacts on our IT or other business systems.

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

Perth Energy will not require any lead time to implement the proposed changes.