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DISCUSSION PAPER: 2014 WHOLESALE ELECTRICITY MARKET REPORT TO THE MINISTER FOR ENERGY

The Independent Market Operator (IMO) welcomes the opportunity to contribute to the Economic Regulation Authority's (ERA's) 2014 Wholesale Electricity Market (WEM) Report to the Minister for Energy (2014 Report).

The IMO supports the ERA's proposal to avoid duplication of the work being undertaken by the State Government's Electricity Market Review (EMR) project team.

The IMO also notes the ERA's recognition in the Discussion Paper published on 19 November 2014 (Discussion Paper) of the IMO's efforts to address some of the issues raised in previous reports to the Minister, including the development and progression of the Rule Change Proposals:

- RC_2013_09: Incentives to Improve Availability of Scheduled Generators[1];
- RC_2013_10: Harmonisation of Supply-Side and Demand-Side Capacity Resources[2];
- RC_2013_20: Changes to the Reserve Capacity Price and the Dynamic Reserve Capacity Refunds Regime[3]; and
- PRC_2014_01: Improvements to the Energy Market[4].

1 See http://www.imowa.com.au/RC_2013_09. On 19 May 2014 the Minister notified the IMO of his decision to not approve the proposed Amending Rules for RC_2013_09.
2 See http://www.imowa.com.au/RC_2013_10. On 19 May 2014 the Minister notified the IMO of his decision to not approve the proposed Amending Rules for RC_2013_10.
3 See http://www.imowa.com.au/RC_2013_20. The first submission period for this proposal closed on 24 February 2014. The IMO has delayed the preparation of the Draft Rule Change Report until the outcomes of the EMR become available.
4 The Pre Rule Change Proposal was last presented to the MAC on 14 May 2014 - see http://www.imowa.com.au/MAC_71. The IMO has delayed the formal submission of the proposal until the outcomes of the EMR become available.

This submission provides the IMO's views on issues raised in the Discussion Paper and suggests one additional issue for the ERA to consider in the preparation of the 2014 Report.

Constrained network

The IMO agrees with the ERA that the issue of constrained network access is one of the most pressing problems currently facing the WEM. The IMO strongly supports the adoption of a constrained network access model for the South West Interconnected System (SWIS). The reasons for this view are outlined in the IMO's submission to the EMR[5], and also in a recent submission to the ERA on Western Power's application for exemption from certain requirements of the Technical Rules for three WestGen solar farms[6].

Each year the IMO assesses the expected impact of any non-firm service arrangements (such as run-back schemes) as part of the process for assigning Certified Reserve Capacity. Based on the information available, the IMO considers that the existing non-firm arrangements are unlikely to have a significant impact on the WEM in the near future as their operation is expected to be infrequent, with no material impact on energy prices or Power System Reliability[7]. However, this may not continue to be the case as the number of interruptible connections grows and the network becomes increasingly constrained.

The IMO has been in discussion with Western Power for several months in relation to Western Power's proposal to provide limited network access to prospective generators in a Competing Applications Group (CAG), using a 'partially constrained' network/market model to be implemented via a 'network constraint tool' (NCT).

The IMO has significant concerns about Western Power's proposal. The IMO and Western Power have considered a number of possible options for such a model but these investigations have identified that a partially constrained network/market model would:

- be unlikely to deliver least-cost generation for the SWIS by preventing the dispatch of lower-price generation;
- increase the risk that the quality and timing of network connection will determine dispatch priority rather than an offer price;
- be likely to compromise the integrity of the Balancing Merit Order (BMO);
- reduce market transparency and undermine the accuracy of forecast pricing; and
- be unlikely to satisfy the Wholesale Market Objectives in order to enact the changes to the Market Rules and Market Procedures required to support the NCT.

At this point the IMO believes the proposed NCT is not feasible as it cannot be implemented successfully under the current regulatory and market framework. However the IMO is continuing to work with Western Power to identify a suitable alternative solution.

5 See Electricity Market Review.
6 See Byford PV Solar Farms - Economic Regulation Authority Western Australia.
7 It should be noted that the curtailment of a Facility through an automated run-back mechanism should not result in the payment of constrained off compensation to the Market Participant.

The IMO and Western Power have agreed in discussions that a constrained network access model, as suggested in the EMR Discussion Paper, would be a superior solution that would eliminate the need for the NCT or an alternative solution. Should an interim solution be required prior to the implementation of a constrained network access framework and market model, this solution should seek to have minimal impact on existing market structures and Market Participants and be 'fit for purpose', recognising that conditions in the Western Australian electricity sector do not currently favour significant investment in new generation. In the IMO's view it is unlikely that the extent of new investment currently contemplated by CAG participants will become operational in the next three to five years.

Balancing Market

The IMO notes the following points in relation to two of the Balancing Market issues proposed by the ERA for consideration in this review.

- *Impact of any bilateral contracts on generator performance and bidding behaviour:* the IMO recommends that the ERA's proposed review should encompass all bilateral contracts, not just those involving Synergy.
- *Future of the STEM in light of development of the Balancing Market:* a review of the STEM is one of the highest priority issues in the current (2013-2016) Market Rules Evolution Plan. While work on the issue has been deferred until the outcomes of the EMR are known, some initial work on options for a modification or replacement of the STEM was undertaken in late 2013. Since the Balancing Market has transformed the STEM from a physical short term energy market to what is now more of a day-ahead financial hedging instrument, the options considered included a move to a more conventional day-ahead trading exchange, as well the provision of platforms to support longer-term (e.g. weekly or monthly) trades. These options were discussed in a paper prepared for the IMO by Mr Jim Truesdale, which was presented to the MAC at its 11 December 2013 meeting[8].

LFAS Market

As noted in the Discussion Paper, the IMO and System Management have made considerable efforts over the last two years to understand the causes of LFAS usage and identify opportunities to reduce the costs of LFAS.

The investigations have been hampered by difficulties in measuring actual LFAS usage due to the way in which Synergy's Balancing Portfolio is currently dispatched, which blurs the boundaries between the energy and Ancillary Services provided by Synergy Facilities. This causes the LFAS analysis to produce exaggerated, 'worst case' LFAS usage measures, which incorporate contingency events that should be regarded as Spinning Reserve or Load Rejection Reserve and assume Synergy Facilities always move in response to erroneous notional Dispatch Instructions.

Despite these difficulties the sources of LFAS have now been identified and analysed. An overview of the sources along with a range of both short term and longer term options to reduce the LFAS Requirement was presented to MAC members at the 3 December 2014 MAC meeting. The presentation, which is available on the IMO

[8] See http://www.imowa.com.au/MAC_67.

website[9], also highlighted the extremely high cost of LFAS in the WEM, in particular when compared to the corresponding cost in the National Electricity Market (NEM).

The IMO and System Management have identified, in addition to the four main LFAS sources (load forecast error, non-scheduled generation forecast error, the dispatch of Facilities at 'non-optimal' ramp rates and the deviation of Scheduled Generators from their Dispatch Instructions), three other error sources (auxiliary load forecast error, 'behind the fence' forecast error and dispatch error) that are the product of the methodology used by the Real Time Dispatch Engine (RTDE) to generate Dispatch Instructions. While the error sources do not result in the actual movement of LFAS Facilities, they distort the LFAS analysis results and may have other adverse market impacts.

A number of opportunities to reduce LFAS costs in the short term have been identified.

- The Technical Rules require System Management to contain the system frequency within the 'normal range' (49.8-50.2 Hz) for 99 per cent of the time. However, the standard adopted by System Management to date has been to maintain frequency within the normal range for 99.9 per cent of the time. In practice, the performance level is even higher – for example, over the period from May 2013 to April 2014 the frequency remained in the normal range for at least 99.97 per cent of each month.

  The international benchmarking exercise conducted by Ernst & Young (EY, formerly ROAM Consulting) for the 2014 Ancillary Service Standards and Requirements Study found that containing the frequency to the normal range for 99.9 per cent of the time is much more onerous than typical frequency standards elsewhere – in the markets EY reviewed the performance standards varied between 97 per cent and 99 per cent. EY's findings indicate that the current performance levels are unnecessarily high and that some reduction of the current LFAS Requirement (+/-72 MW) should be achievable without creating a risk to system security or requiring any other remedial action.

- The analysis indicates that LFAS usage is often well below the current +/-72 MW LFAS Requirement for extended periods, in particular overnight (e.g. between 12:00 am and 5:00 am). The results suggest there is potential to reduce (or 'sculpt') the LFAS Requirement for these periods when key forecast parameters (e.g. weather) are favourable. System Management has committed to investigate this opportunity further and report back to the MAC in March 2015.

- System Management is currently estimating the time and cost requirements to amend the RTDE to use persistence forecasting to estimate auxiliary load, and proposes to report back on this option to the MAC in February 2015.

- Scope exists to improve the speed and consistency of controller response when Facilities fail to comply with a Dispatch Instruction, so that the appropriate constraints are applied in the RTDE and amended Dispatch Instructions are issued in a timely manner, reducing the LFAS impact of the event.

- System Management currently issues all Dispatch Instructions using the Ramp Rate Limit specified in the Facility's Balancing Submission. In most cases this is necessary to avoid excessive constrained on/off payments. However, when

9 See http://www.imowa.com.au/MAC_77.

dispatching a Non-Scheduled Generator 'out of merit' the use of a lower ramp rate would actually reduce the size of any constraint payments.

The IMO has asked System Management to assess the cost and time needed to amend its systems to support more flexible ramping, so that an assessment can be made of the feasibility of this option (which would also require a number of settlement changes) in the short to medium term.

The IMO and System Management have identified a number of other options with potential to significantly reduce LFAS costs, but as these require more significant, longer-term changes they are considered to be dependent on the outcomes of the EMR. While the future evolution path for the WEM is currently uncertain, the IMO expects that the optimal solution would incorporate:

- a co-optimised energy and Ancillary Services market;
- reduced gate closure and dispatch cycle times;
- improved forecasting accuracy and the reduction/removal of system-generated LFAS sources such as auxiliary load forecast error;
- facility based bidding and dispatch for all Market Participants (which would allow for more accurate measurement of LFAS usage and the contributing LFAS causes); and
- 'causer pays' allocation of LFAS costs.

Changes to support more flexible ramp rates and/or limit maximum ramp rates would also be beneficial, as would changes to specify a maximum period of non-compliance with a Dispatch Instruction after which System Management must treat a Facility as unavailable. Several of these recommendations were also made by EY in its Final Report for the 2014 Ancillary Service Standards and Requirements Study.

The IMO would be happy to meet with the ERA to discuss the current issues affecting LFAS costs and the outcomes of the IMO's and System Management's investigation into the LFAS Requirement.

Sustained network and generator outages

Use of Dispatch Support and Network Control Service Contracts

Events following the failure of the second Muja bus-tie transformer in February 2014 have highlighted significant issues with the current arrangements for managing extended network constraints. In particular, the IMO considers that the current arrangements around the use of Ancillary Service Contracts for Dispatch Support Service (DSSCs) and Network Control Service Contracts (NCSCs) are adversely impacting on the efficiency of the WEM and require urgent review.

The WEM's current constraint payment mechanism is only designed to address short term interruptions to normal dispatch. The use of this mechanism to manage out of merit dispatch for an extended network outage:

- may fail to adequately compensate a Market Participant that offers into the Balancing Market at its short run marginal cost (SRMC);
- distorts the Forecast BMO and the forecast Balancing Price; and

- imposes significant and unpredictable costs on Market Participants.

The Balancing Market design assumes that any extended network constraint will be managed through a DSSC or NCSC. However:

- the criteria for when a DSSC or NCSC may and/or should be employed are not well-defined;
- the distinction between a DSSC (which is procured by System Management and paid for by Market Participants) and an NCSC (which is procured by Western Power and recovered through future network tariffs under the Access Arrangement) is not clear;
- the incentives for System Management or Western Power to enter into a DSSC or NCSC (respectively) appear insufficient;
- the contracting process is likely to be protracted, which can limit the effectiveness of these contracts for all but very long term constraints; and
- for DSSCs, the costs are allocated to Market Participants - who are unable to provide an effective response – rather than to the Network Operator, the party that is best able to assess the risks involved and manage the cause of the issue.

These issues were discussed at a meeting of the Market Advisory Committee (MAC) held on 24 September 2014, during a presentation by the IMO of a Concept Paper[10] suggesting an option to streamline the DSSC procurement process[11]. On 30 September 2014 the IMO sent a letter to the Public Utilities Office (PUO) on behalf of MAC members, outlining their concerns and requesting the PUO consider the current arrangements for DSSCs and NCSCs and consider the State Government's policy position on:

- an appropriate allocation of market and non-market costs (i.e. under DSSCs and NCSCs) in the SWIS;
- whether it is appropriate to mandate the use of NCSCs in certain circumstances to avoid an inefficient cross-subsidy; and
- the appropriateness of a contingency arrangement such as that proposed by the IMO at the September 2014 MAC meeting.

The IMO supports the further consideration of DSSC and NCSC arrangements as part of the ERA's preparation of the 2014 Report.

Criteria for dealing with Forced Outages

In its Discussion Paper, the ERA proposes to consider whether the criteria System Management is required to use under the Market Rules when dealing with Forced Outages results in the lowest cost option. The IMO notes that in some very rare circumstances it is possible that the application of clauses 7.6.1C and 7.6.1D of the Market Rules may not result in the selection of the lowest cost dispatch option. Further, the dispatch of part of a Demand Side Programme (DSP) to assist with a

10 See the Concept Paper: Annual Approval of Facility Costs to Streamline Ancillary Service Procurement (CP_2014_08), available at http://www.imowa.com.au/MAC_75.

11 A copy of this letter was published in the papers for the 3 December 2014 MAC meeting, available at http://www.imowa.com.au/mac_77.

specific network constraint can be problematic under the current Market Rules, which do not consider the geographic locations of the Associated Loads of a DSP.

Although options exist to address these concerns the issues involved are very complex and it is difficult to assess the viability of potential solutions while the outcomes of the EMR remain unknown. However, the IMO would be happy to meet with the ERA to discuss these issues further.

Criteria for approval of Planned Outages

The IMO supports the ERA's proposal to review the criteria used by System Management for approving Planned Outages. The IMO notes that the criteria currently prescribed in the Market Rules do not include any explicit consideration of commercial impacts on the market and their application may in some circumstances contribute to short-term increases in energy prices in the WEM.

Cost allocation for Load Rejection Reserve Service

On 13 August 2014 System Management gave a presentation to the MAC on the outcomes of a modelling exercise to estimate the cost impact of increasing the Ancillary Services Requirement for Load Rejection Reserve Service (LRRS) from its current level of 120 MW to about 240 MW.

The work was requested by Western Power to assist its assessment of an access request for a large new block load. The modelling was carried out by Jacobs SKM using an extension of the model used to calculate the values of Margin_Peak and Margin_Off-Peak (margin values) for the 2014-15 Financial Year. The margin values are key components of the administered price paid for Spinning Reserve Service provided by Synergy.

The results predicted that as the requirement increased from 120 MW to 240 MW the cost to provide LRRS increased steadily from the current $0 per year up to nearly $40 million per year. While this figure was only a preliminary estimate and did not consider some potentially cheaper LRRS provision options (such as tripping off selected generators rather than just reducing their output to minimum stable generation levels), the results highlight the potential for LRRS costs in the WEM to grow to significant levels in future years.

Under the current Market Rules, LRRS costs are allocated to Market Participants based on the proportion of total consumption attributable to each participant. However, in reality the LRRS requirement is determined by the overall network configuration and the location of specific major Loads. As indicated by the modelling results, the relative consumption of a Load does not provide an accurate measure of its relative contribution to the LRRS requirement.

The IMO notes that the Network Operator is both the party responsible for the overall configuration of the network and the holder of the information required to make informed decisions about the efficient allocation of LRRS costs to end users. The IMO considers that it may therefore be more appropriate to consider whether, and if so to what extent, LRRS costs should be allocated to the Network Operator in the first instance.

For this reason, the IMO recommends that in its preparation of the 2014 Report the ERA considers whether the current arrangement for the allocation of LRRS costs is the most efficient option.

Contact for further discussion

If you would like to further discuss any matters raised in this submission, please contact Kate Ryan on 08 9254 4357 or by email to kate.ryan@imowa.com.au.

Yours sincerely

ALLAN DAWSON
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9 January 2015