2014 Wholesale Electricity Market Report to the Minister for Energy

Public Version

February 2015

Economic Regulation Authority
WESTERN AUSTRALIA

For further information, contact

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

Contents

EXECUTIVE SUMMARY

Introduction

The Authority's review of the effectiveness of the Wholesale Electricity Market (**WEM**) has coincided with the State Government's Electricity Market Review (**EMR**) initiated by the Minister for Energy on 6 March 2014. The Authority welcomes and supports the review and is pleased to note it is addressing the major areas of concern the Authority has raised in previous Reports.[1]

Recognising that the EMR has put significant resources into the major issues identified by the Authority in previous reports, the Authority has not duplicated that work in this review.

The Authority considers the most pressing problems the Government should deal with are:

- Industry structure including government ownership and lack of competition;
- Market governance (including the State Government's conflict);
- The Reserve Capacity Mechanism (**RCM**); and
- Constrained network access.

The Authority's concerns in relation to each of these are summarised below.

Industry structure

The number and market share of Independent Power Producers (**IPPs**) and independent retailers has increased significantly since the WEM commenced. However, the market continues to be dominated by Synergy, particularly following the merger of Verve Energy and Synergy on 1 January 2014. In the absence of a clear policy framework for increasing retail competition, Synergy's dominance severely limits the prospect of further entry and expansion of other retailers. Greater competition is important because it will lead to outcomes that are in the long term interests of consumers.

The initial industry structure separated the Government owned retail and generation businesses and included a vesting contract designed to encourage new entrants into the market, similar to measures successfully undertaken in other jurisdictions. However, various Government interventions[2] and the failure to develop retail competition have restricted the establishment of effective competition in the WEM.

The current market design incorporates a number of mitigation measures to address Synergy's market power. These include monitoring market offers to ensure participants do not price above short run marginal cost (**SRMC**) where that behaviour relates to market power, and setting Energy Price Limits (**EPLs**) and the Maximum Reserve Capacity Price (**MRCP**). Maintaining and monitoring these measures is time consuming and costly, and such regulatory oversight will always be a second best option to efficient market design and a competitive industry structure.

[1] See ERA submission to EMR Discussion Paper http://www.finance.wa.gov.au/cms/uploadedFiles/Public_Utilities_Office/Electricity_Market_Review/ERA.pdf

[2] For example, changes to the vesting contract and the re-merger of Verve Energy and Synergy.

Further mitigation in the form of the *Electricity Corporations (Electricity Generation and Retail Corporation) Regulations 2013* (**EGRC Regulations**)[3] has been necessary as a result of the recent merger of Verve Energy and Synergy. The Authority is currently undertaking a review of the operational effectiveness of the EGRC Regulations and will be reporting separately on this matter. However, at best the EGRC Regulations will ensure there is no deterioration in competition due to the merger of the generation and retail arms. The Regulations do not address broader issues of market dominance and the eventual development of choice for consumers over retail supply.

If the Government addresses industry structure effectively then it may be possible to remove or reduce the current regulatory market power measures. However, if this does not occur then the existing market power constraints, including the EGRC Regulatory Scheme, will need to be retained and quite likely strengthened.

Unless industry structure issues are dealt with to enable a competitive market to develop, any market design will be problematic.

Market governance

Government ownership in a contestable market is a significant impediment to the development of competition in the WEM. As set out in the Authority's Inquiry into Microeconomic Reform in Western Australia, there is a conflict of interest for government when it is an owner of assets in markets where those government-owned assets are competing with private sector companies.

Government ownership related intervention has been a significant contributor to the limited competition now seen in the WEM and the cost of producing electricity in Western Australia. For example, the vesting contracts between Synergy and Verve Energy were revised in 2010 resulting in commercial benefit to the Government as a business owner. These interventions removed market power mitigation measures that had been implemented at market commencement to encourage greater private sector participation.[4]

Aside from government conflict of interest, continuing concerns regarding the governance arrangements for the WEM have been raised by stakeholders, both directly to the Authority and in submissions to Rule Changes proposed by the IMO. These concerns included structural features that characterise bigger markets, such as separation of the rule making function from market operation, and having a standalone system manager. The Authority considers changes to the governance arrangements are now necessary to strengthen confidence in the market, particularly following the merger of the two largest market participants.

Reserve Capacity Mechanism

The purpose of the capacity mechanism is to provide incentives for timely investment in capacity to meet system security and adequacy requirements. However, the capacity mechanism is clearly not working as originally planned. A number of factors have

[3] The EGRC Regulations impose requirements on Synergy including ring-fencing, business segregation, transfer pricing and non-discriminatory wholesale electricity trading.

[4] See page 3-4 of ERA submission to EMR Discussion Paper http://www.finance.wa.gov.au/cms/uploadedFiles/Public_Utilities_Office/Electricity_Market_Review/ERA.pdf

contributed to the high cost to the market of the excess capacity that has been secured under the RCM. These are summarised below.

The reliability requirement in the WEM requires almost every conceivable contingency to be covered. This contrasts with the NEM which allows for some minor unserved load in every jurisdiction in every year. The WEM approach has led to excess capacity being procured in the WEM, with an associated cost. Setting reliability standards is a judgement for policy makers. It is not appropriate for the Authority, as a regulator, to make a judgement on reliability requirements. However, the Authority notes the costs are significant.

Demand forecasts are inevitably imperfect. However, the current arrangement, under which the IMO is responsible for ensuring sufficient capacity is available whilst also preparing the demand forecast, could unintentionally incentivise the IMO to over-forecast the energy and capacity needed. This is because the IMO bears considerable institutional risk if it were to under-forecast demand, but does not bear any monetary risk if it were to over-forecast demand as the cost is met by market customers.

The price paid for capacity is based on the Maximum Reserve Capacity Price (**MRCP**). This is a flawed approach. The MRCP is a price cap applied to mitigate market power in the event that a capacity auction is held. It should not be used for sending investment signals to investors for building new capacity, or pricing capacity payments for existing generators, as is currently the case. A market-based discovery tool such as an auction would be a superior way to value and procure reserve capacity.

The optimal capacity mix for the WEM is one that provides the least cost solution for energy and capacity combined. However, the current approach, which uses a single price for all types of capacity, has arguably not achieved this. Alternative methods could be used such as those adopted in parts of North America whereby apportioned markets differentiate the value of capacity payment streams based on a set of critical operational capabilities or reliability attributes.

The Authority notes that the current capacity mechanism does not provide strong incentives for old and expensive plant to retire at an appropriate time. This leads to an inefficient mix of generation in the market, impacting on the ability of more efficient and newer plants to enter the market. The Authority considers that this dis-incentive to retire plant at an appropriate time should be addressed in the WEM capacity mechanism.

Whilst recognising that the IMO has continued to progress development of Rule Changes[5] which might alleviate many of the above issues, a comprehensive review, as is being undertaken by the EMR, is essential to ensure the issues raised by the Authority are addressed.

---

5 The changes being progressed by the IMO included:

- Changes to the RCP proposed by the RCMWG (not yet in formal rule change process)
- Harmonisation of demand-side and supply –side capacity resources proposed by RCMWG (RC_2013_10 released for consultation in August 2013)
- Incentives to improve availability of scheduled generators (RC_2013_09 released for consultation in June 2013)

Constrained network access

Network planning in relation to managing system congestion is a key issue for all electricity networks and a variety of approaches have been adopted around the world with varying degrees of success. Unlike the NEM, which is based on constrained network access, the WEM does not have a prescribed approach. Western Power's approach has been to connect generators on an unconstrained basis (i.e. generators can supply electricity into the network without limitation for credible contingencies) and this is reflected in its approved Technical Rules.

An unconstrained network approach facilitates simpler operation of the power system and market because of the absence of dynamic physical constraints. However, it may not result in the most economically efficient development of the network.

The Authority has previously recommended a full and detailed review of the costs, benefits and possible implementation issues relating to a move towards a constrained network access model for the WEM.

Current operational issues

If it is decided to retain the current market design (albeit with some modification), the Authority has identified a number of issues which could be dealt with under existing approval processes.

Network connection policies

In some parts of the network the cost of upgrades to provide unconstrained access are significant and, as a result, prospective generators do not want, or cannot afford, the cost of connection. As noted above, a policy decision is required as to whether a constrained network should be adopted as a general approach. Whilst it waits for this policy decision, Western Power must continue to process new customer connections effectively.

In this context, Western Power has provided constrained connections over the last few years for a small number of customers by seeking specific exemptions from the Technical Rules.[6] Any network constraints associated with such connections are expected to occur on an infrequent basis with no material impact on wholesale energy prices or power system reliability.

However, the Authority is aware that Western Power is now proposing to introduce a more complex connection approach for groups of new customers in constrained parts of the network. The processes required to implement this new approach do not appear to have been contemplated in Western Power's approved Applications and Queuing Policy (**AQP**) or Technical Rules. Introducing such arrangements without a proper review of the AQP and Technical Rules could potentially result in failure to achieve the Code and WEM objectives. Given these emerging issues, the Authority considers the AQP and Technical Rules are in need of review.

Balancing Market

The new Balancing Market has delivered significant improvements and increased the competitiveness of the WEM. The IMO's list of planned refinements of the Balancing Market

[6] These exemptions are required to be approved by the Authority.

is comprehensive and will deliver further improvements. Progress of these refinements awaits the outcome of the EMR.

If the Government decides to retain the current market design, priority should be given to those developments which have the greatest impact on removing barriers and improving incentives for generators to fully participate in the market. These include reducing gate closure times and improving the accuracy of forecast loads and prices. A review of the Short Term Energy Market (**STEM**) should also be a high priority to ensure it provides value for the transaction costs incurred by participants and the administrative effort required to support it. Clarity regarding the future market design is needed as soon as possible to enable these developments to progress.

Load Following Ancillary Services (LFAS) Market

LFAS Prices were very high when the new LFAS market commenced in July 2012. Although prices have now reduced they are significantly higher than for similar services in the NEM. Considerable effort has been made by the IMO and System Management to better understand the LFAS requirement and this work is ongoing. The IMO's list of planned refinements to the LFAS market is comprehensive. The IMO has also identified improvements in other areas of the Market Rules (e.g. reduced gate closure times) which would facilitate better LFAS outcomes.

Whilst there are a number of short term opportunities currently being worked on, more significant longer term changes have been deferred until the outcome of the EMR is known.

Currently the costs of LFAS are spread across all market customers. The Authority considers high priority should be given to introducing the principle of user (or causer) pays as this will increase the opportunities and incentives for cost reduction.

Sustained outages

Despite significant transmission outages during the 2013/14 year, system security has generally been maintained. However, improvements could be made to streamline the process for managing system security during network outages and ensuring costs are minimised.

The criteria System Management is required to use under the Market Rules when dealing with forced network outages may not always result in the lowest overall cost. Outcomes could be improved by:

- Providing System Management with visibility of prices
- Changing rules around use of Demand-Side Management (**DSM**) to provide a more flexible method for dealing with localised outages

System Management should retain responsibility for ensuring power system security, including deciding how to deal with forced outages on the network. Providing it has access to all the relevant cost information, System Management is best placed to ensure the right balance between system security and cost.

However, the Authority considers changes to the Market Rules are required to allocate constrained on/off compensation and ancillary service costs on a user (or causer) pays basis to improve incentives for efficient market outcomes. Ensuring Western Power faces all the costs arising due to transmission constraints (including those currently paid for by market customers) would provide better signals for network planning and investment.

Conclusion

The Authority welcomes the EMR and considers the review is necessary to address matters raised in previous reports to the Minister. Timely resolution of these issues and clear policy direction is now required.

The Authority will be providing separate reports to the Minister on the effectiveness of the EGRC Regulations and investigations into Vinalco Energy's pricing behaviour. These reports may identify further areas for market improvement.

Recognising that the EMR has put significant resources into the major issues identified by the Authority in previous reports, the Authority did not consider it efficient for this review to duplicate that work. Consequently, this report has focussed on operational matters affecting the market which can be resolved within current approval processes.

Introduction

Background

Section 128 of the *Electricity Industry Act 2004* requires the Authority to provide a report to the Minister every three years, based on a review of the extent to which the market objectives set out in the Act have been, or are being, achieved. The last triennial report was published in August 2011. This triennial report was required to be provided to the Minister within three years and six months of the previous report being tabled in Parliament.[7]

In addition, the *Wholesale Electricity Market Rules* (**Market Rules**)[8] require the Economic Regulation Authority (**Authority**) to provide to the Western Australian Minister for Energy (**Minister**) a report (**Report to the Minister**) on the effectiveness of the Wholesale Electricity Market (**WEM**) in meeting the Wholesale Market Objectives (**Market Objectives**),[9] at least annually.[10]

The Authority has prepared a single report covering both obligations, consistent with the approach taken in previous years.

This report fulfils the Authority's requirements under the Market Rules for the period from 1 July 2013 to 30 June 2014.

Process

As part of the preparation process for the 2014 Report to the Minister, the Authority released a Discussion Paper[11] seeking public submissions on issues impacting the effectiveness of the WEM on 19 November 2014.

The Authority also posted a notice on the Authority's website advising of the release of the Discussion Paper and invited interested parties to make submissions to the Authority by 12 January 2015. An advertisement inviting public submissions was published in the West Australian newspaper on 24 November 2014. A list of submissions received in response to

---

[7] Section 128(3) of Electricity Industry Act 2004.

[8] See State Law Publisher website, Electricity Industry (Wholesale Electricity Market) Regulations 2004: Wholesale Electricity Market Amending Rules (September 2006), http://www.slp.wa.gov.au/gazette/GAZETTE.NSF/searchgazette/43EDE36827EBE11F482571ED0023C9C5/$file/gg161.pdf

[9] The Market Objectives 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 SWIS, 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 SWIS; and (e) to encourage the taking of measures to manage the amount of electricity used and when it is used.

[10] Pursuant to clause 2.16.11 of the Market Rules, the report must be produced at least annually, or more frequently where the Authority considers that the WEM is not effectively meeting its Market Objectives.

[11] See ERA website, Discussion Paper – 2014 Wholesale Electricity Market Report to the Minister for Energy – 19 November 2014, http://www.erawa.com.au/cproot/13009/2/20141119%202014%20Ministers%20Report%20Discussion%20Paper.pdf

the Authority's Discussion Paper are provided in Appendix 1 and available on the Authority's website.[12]

In preparing this Report to the Minister, and in forming the views set out in it, the Authority has considered the comments raised in the submissions provided to the Authority. Matters not specifically addressed in this report will be considered in future reports.

Confidentiality

Clause 2.16.15 of the Market Rules requires that, where the Authority provides a report to the Minister in accordance with clause 2.16.11, the Authority must, after consultation with the Minister, publish a version of the report that has confidential or sensitive information aggregated or removed.

Information that is classified as confidential under Chapter 10 of the Market Rules has been identified by the Authority and will be aggregated or removed in the public version. This report is the confidential version to the Minister.

Structure of this report

The Executive Summary includes issues the Authority has identified in previous reports which it considers are adversely impacting the effectiveness of the market in meeting the Market Objectives.

Section 2 sets out the particular matters the Authority has reviewed in 2014.

The detailed analysis and data required under the Market Rules is included in Appendix 2 to this report.

[12] See ERA website, Annual Wholesale Electricity Market Report to the Minister for Energy web page, http://www.erawa.com.au/electricity/wholesale-electricity-market/annual-report-to-the-minister/2014-ministers-report

2014 Review

The WEM is composed of two key components: an energy market and a capacity mechanism. The purpose of the capacity mechanism is to provide incentives for continued investment in existing and new capacity to meet system security and adequacy requirements.

The energy market deals with the trading of energy between Market Participants and includes Bilateral Contracts, the Short Term Energy Market (**STEM**) and the Balancing Market. The WEM was designed under the assumption that retailers would cover the majority of their electricity requirements through Bilateral Contracts with generators. The STEM enables Market Participants to adjust their contract positions by buying or selling energy on the day before the energy will be delivered. The Balancing Market enables generators to make further adjustments closer to real-time, and is the mechanism that determines actual economic dispatch.

A key factor underlying the original design of the WEM was that the South West Interconnected System (**SWIS**), covered by the WEM, is an isolated system. In other words, it cannot rely on any interconnections with other systems and must therefore have sufficient capacity within itself to satisfy demand and deal with emergency situations affecting supply.

The WEM has undergone significant development since it first commenced. In particular, the introduction of competitive Balancing and Load Following Ancillary Service (**LFAS**) markets on 1 July 2012 were a major milestone. These markets have provided opportunities for Independent Power Producers (**IPPs**) to participate in the provision of balancing energy and LFAS which previously were provided exclusively by Verve Energy.

Recognising that the Electricity Market Review (**EMR**) has recently put significant resources into the major issues identified by the Authority and others in the past, the Authority did not consider it efficient for this review to duplicate the work being undertaken by the EMR project team. It has also not repeated the matters reported to the Minister in previous years in any detail.

The particular matters the Authority has reviewed in 2014 include:

- Network access
- Balancing Market
- LFAS Market
- Sustained outages

Network connection policies

Key findings

Network planning in relation to congestion management is a key issue for all electricity networks and a variety of approaches have been adopted around the world with varying degrees of success. Unlike the explicit constrained network access regime of the NEM, the WEM does not have a prescribed approach. The Access Code can accommodate a variety of approaches, provided they achieve the objective of promoting the economically efficient investment in and operation and use of the network in order to promote competition in markets upstream and downstream of the network.

In some parts of the network, the cost of upgrades to provide unconstrained access are significant and, as a result, prospective generators do not want, or cannot afford, the cost of connection. Western Power has entered into a small number of constrained customer connections. Operation of these arrangements is expected to be infrequent with no material impact on energy prices or power system reliability in the near term. However, as there have been a number of requests for exemptions to the Technical Rules to enable such constrained connections, it would be more efficient to review the Technical Rules to identify whether an amendment of the rules is required to deal with constrained connections of this nature if they were to be requested in future.

In the absence of a proper review of the approach to managing congestion, Western Power is now proposing to introduce a more complex connection process for groups of new customers in constrained parts of the network. The processes Western Power is contemplating are complex and potentially will impact on the efficiency of the dispatch mechanism. Before any such processes are introduced a review is required to ensure the Access Code and WEM objectives are achieved.

Background

The WEM design is based on the unconstrained network access concept, and assumes generators have full access to the network during times of peak electricity demand, even after a single credible network fault.[13] An unconstrained network approach facilitates simpler operation of the power system and market because of the absence of dynamic physical constraints.[14]

The Authority has raised concerns in previous reports to the Minister that the current unconstrained network access approach in the SWIS does not enhance the Market Objectives and recommended that a full and detailed review be undertaken of the costs, benefits and possible implementation issues relating to a move towards a constrained network access framework.

[13] There are various definitions of the concept of unconstrained network access and the terms ‘unconstrained access’ or ‘firm access’ are often used.

[14] ‘Physical constraints’ are limitations on the operation of a network asset, a group of assets or a whole area of the network due to performance requirements across a range of factors including power quality, security of supply, safety and power system stability.

As noted in the Authority's 2013 WEM Report, there has been an increasing number of interruptible customer connections offered by Western Power. Whilst this approach is more likely to deliver reduced network connection costs, the interaction with the operation of the WEM and network investment also needs to be considered. Until a policy decision in relation to the overall approach is agreed there is a significant risk that a piecemeal and uncoordinated adoption of constrained network access will not result in an optimal overall solution.

Submissions received from Western Power, System Management and the IMO during the Authority's public consultation included comments on constrained access. They all expressed support for moving to a constrained network approach.

The Authority is pleased to see that the EMR is considering whether the market should move to a constrained model. The Authority supports this review and notes that a number of submissions to the EMR Panel provided useful discussion and suggestions in relation to this matter. A clear direction is needed as soon as possible.

In this report, the Authority has focused on the issues arising now, or emerging, as a result of some generators being connected on a constrained basis. Although these issues should be resolved when an overall solution is adopted, depending on how long this takes, it may be necessary to make changes in the interim.

Approach in the WEM

The WEM does not have a prescribed approach to network access. The objective of the *Electricity Networks Access Code 2004* (**Access Code**) is to promote the economically efficient investment in and operation and use of the network in order to promote competition in markets upstream and downstream of the network.

The Access Code requires Western Power to:

- Use all reasonable endeavours to accommodate an applicant's requirement to connect to the network;
- Expeditiously and diligently process access applications; and
- Negotiate in good faith with applicants regarding the terms for an access contract.

Western Power's Access Arrangement (which is reviewed and approved periodically by the Authority) sets out how Western Power will achieve these objectives. The Access Arrangement is required to include an Applications and Queuing Policy (**AQP**) setting out the network connection process for new connections. Western Power is also required to have Technical Rules approved by the Authority setting out the standards, procedures and planning criteria governing the construction and operation of an electricity network.

Generally new connections are required to comply with Western Power's Technical Rules. As noted in Western Power's submission, although not formally codified in any legislation, currently there is a generally accepted design principle that generators connected to the Western Power Network are unconstrained (i.e. can supply electricity into the network without limitation for credible contingencies) with the network planned, designed and built to enable this. Currently the Technical Rules require the transmission system to be planned such that, where the peak load of a part of a network is greater than a minimum power threshold, there must be sufficient redundancy built into the network to maintain supply and avoid load shedding if any one transmission element, such as a transmission line or transformer, is out of service.[15] This requirement applies irrespective of the generation schedule. Western Power's approved reference services are based on connections that comply with these Technical Rules.

However, subject to the AQP and Technical Rules, Western Power and a user or network access applicant may negotiate a contract for access to any service (including a service which differs from a reference service) on any terms (including terms which differ from a standard access contract).

In the event that a customer requests or is willing to accept a non-Technical Rule compliant connection (such as a constrained connection), Western Power may apply to the Authority for exemptions from its approved Technical Rules.

Under the Code, the Authority must consider applications for exemptions from the Technical Rules as a reasonable and prudent person on reasonable technical and operational grounds, having regard to the effect the proposed exemption will have on Western Power, users of the network and any interconnected network. It must grant the exemption if it determines that in all circumstances the disadvantages of requiring compliance with the Rules are likely to exceed the advantages.

Approach in other jurisdictions

Network planning in relation to congestion management is a key issue for all electricity networks and a variety of approaches have been tried with varying degrees of success.

The NEM is an important example of a constrained network access regime. Transmission network constraints are fully and transparently captured in the underlying constraint equations that form the NEM's security-constrained economic dispatch model. For any given potential transmission constraint, each generator's ability to alleviate (or worsen) congestion is represented mathematically, enabling appropriate dispatch to maintain system security and meet load within the regional nodal pricing framework. Overall, this market design is effective and efficient and has delivered substantial benefits to consumers.

However, generators do not have transmission access rights within the NEM, and no constrained on or off payments are made when congestion binds. Under some circumstances, generator profitability may therefore be negatively affected, representing a dispatch risk. Complex issues regarding generator rebidding behaviour[16] in relation to network congestion have arisen in consequence. The costly and inefficient outcomes that may result from this 'disorderly bidding' are an ongoing matter of concern, in particular inter-regional counter-price power flows.

Further concerns have arisen that the separation of generator investment incentives from centralised transmission planning in the NEM may not minimise total system costs. In particular, a generator may be willing to fund network augmentation, but it is not occurring because currently there is no mechanism for the generator to be given secure access to the expanded transmission capacity. In response to this and related issues the AEMC is in the process of developing the optional firm access model (**OFA**), which would establish the ability to buy firm access rights as a means to insure against transmission congestion. The

[15] This is known within the industry as an N-1 situation.

[16] Generators are allowed to adjust the capacity assigned to their submitted price-quantity bands, as well as technical parameters such as ramp rate, up to 5 minutes before dispatch, thus in effect changing their supply schedule.

OFA proposals are widely regarded as the most significant potential change to the NEM since market inception.

In contrast to the NEM, the Alberta Interconnected Electric System (**AIES**) is believed[17] to be the only example of an unconstrained transmission network access regime other than the SWIS. The establishing legislative framework is explicit that the AIES is to be planned, built, and operated on a congestion-free basis. Unconstrained access is held to enable a fair, efficient, and openly competitive market, and as a matter of principle insufficient transmission capacity should not hinder investments in load or generation. Similarly, wholesale trading of electricity should not be subject to limitations caused by transmission congestion precluding dispatch of energy according to economic merit. The planning criteria include the provision that transmission of all in-merit energy should occur 95 per cent of the time on an annual basis under abnormal operating conditions, and 100 per cent under normal conditions.

Accordingly, though generators also do not have transmission rights in the AIES, the network is proactively planned by the system operator to anticipate and keep pace with load growth and to support new generator competition. Network augmentation needs are identified by the system operator and then subject to approval by the regulator. New generator entrants must contribute to network upgrades through a locational price signal mechanism, but are not required to meet deep connection costs and the contribution is in fact refunded over the following 10 years. Transmission constraints that do arise are generally regarded as abnormal and are to be redressed as stipulated in legislation – congestion is to be removed in the long-run, with few exceptions.

Nonetheless, protracted transmission congestion has occurred in some areas of Alberta over recent years, particularly the high growth major urban Calgary-Edmonton corridor, partly due to procedural disputes relating to the approvals process. This congestion resulted in substantial inefficient costs caused by the inflationary market price effect of extended out of merit generation, highlighting deficiencies in the real-time congestion management process. A series of decisions by the regulator have led to significant (though still progressing) revisions to the constraint management process, specifically to ameliorate the price distortion of out of merit generation, including directions to use contracted network support ancillary services for foreseen events.[18] These changes to minimise inefficiencies during real-time congestion, in combination with substantial transmission capacity expansion, now coming online, appear to have addressed congestion in the AIES network by adhering to the overall legislated congestion-free principle.

Existing constrained connections

As noted in Western Power’s submission, there are some parts of the network where the cost of upgrades to provide unconstrained access are significant and, as a result, prospective generators do not want, or cannot afford, the cost of connection. In some cases generators have accepted a connection on a partially constrained basis using ‘runback schemes’ which detect real time line overloads and send signals to generators to quickly reduce their output.

[17] As noted by the IMO in their submission to the EMR.

[18] Of note for the present discussion is that the regulator and system operator both considered the question of constrained off compensation payments and found them to be unwarranted.

The Authority notes that since 2012 it has received several applications from Western Power for exemptions to enable it to offer constrained connections to certain customers (both loads and generators).[19]

The Authority notes that the IMO's submission considers existing constrained connection arrangements are unlikely to have a significant impact on the WEM in the near future. The IMO stated that each year it assesses the expected impact of any non-firm service arrangements (such as runback schemes) as part of the process for assigning Certified Reserve Capacity. It also noted that curtailment of a generator through a runback mechanism should not result in the payment of constrained off compensation. Based on the information available, the IMO considers that operation of the existing non-firm arrangements are expected to be infrequent with no material impact on energy prices or power system reliability.

There is no explicit requirement in the Code to consider the impact of such an exemption on the WEM. However, as the Authority is required to have regard to the effect the proposed exemption will have on users of the network, the Authority considers this would include WEM participants.

In the short term, the Authority considers the Code requirement for it to have regard to the effect any proposed exemption will have on users of the network should be adequate to ensure new non-firm connection arrangements do not adversely impact on the operation of the WEM.

However, rather than continuing to seek ad hoc exemptions, the Authority considers it would be more efficient to review the Technical Rules to identify whether an amendment of the rules is required to deal with constrained connections of this nature if they were to be requested in future.

Future connections

Whilst runback schemes such as those described above, have allowed new entrants to connect to the network, Western Power considers allowing further constrained connections on an individual basis increases the risk that supply to customers may be disrupted, safety compromised and increased Technical Rule non-compliance.

To avoid these issues, Western Power considers there is a need for a more centralised, coordinated and flexible control scheme and has proposed a Network Constraint Tool (**NCT**) to enable this.

The IMO has significant concerns with Western Power's proposal to provide limited network access to prospective generators using a partially constrained network/market model implemented via the proposed NCT.

The IMO considers that, at this point, the proposed NCT is not feasible as it cannot be implemented successfully under the current regulatory and market framework. It considers a constrained network access model would be a superior solution that would eliminate the need for the NCT or some alternative. It notes that, if an interim solution is required it should seek to have minimal impact on existing market structures and Market Participants and be 'fit for purpose', recognising that conditions in the WA electricity sector do not currently favour significant investment in new generation.

[19] See http://www.erawa.com.au/electricity/electricity-access/western-power-network/technical-rules/exemptions-from-technical-rules for details of exemptions approved by the Authority.

Although System Management's submission to the Authority does not specifically comment on Western Power's proposed NCT, it does note that it considers any intermediary measures put in place in lieu of a full review of the interaction of the Access Code and WEM Rules will create difficulties in managing system security and reliability.

As noted above, the Code requires Western Power to use all reasonable endeavours to accommodate an applicant's requirement to connect to the network. The process for how Western Power ensures this is achieved is set out in its approved AQP.

Prior to the most recent access arrangement review, Western Power's AQP operated on a first come first served basis. For the access arrangement period covering 2012/13-2016/17, which was approved by the Authority in 2012, Western Power proposed significant changes to the AQP including the creation of 'competing applications groups' (**CAGs**). Western Power described the benefits of this as:

> … applicants are grouped behind common network constraints to assess and tailor joint network solutions to provide access to all applicants within the CAG – rather than the current process which provides one-off, single applicant solutions that leads to the less efficient and more costly augmentation of our network over time.

Clause 24.1(a) of the AQP states that where Western Power assesses that an *application* is competing with other *applications* then Western Power will, subject to clause 16.5, manage *competing applications* by forming them into one or more *competing applications groups* and assessing a single set of *works* for *shared assets* required to meet some or all of the requirements of each *competing applications group.* Where there are more than two *competing applications* Western Power may form all the *competing applications* into one *competing applications group* or it may form them into two or more *competing applications groups* as Western Power considers appropriate given the nature of the *applications,* including how the *competing applications* impede each other in respect of *network* constraints, the size of the *capacity* sought in each of the *competing applications*, and the current level of *spare capacity*.

The Authority's understanding of the benefits of introducing the CAG concept was that it would increase the opportunities to undertake more efficient augmentations through economies of scale by satisfying a group of customers rather than just one.

Augmentation investment required to enable a new connection which meets the New Facilities Investment Test (**NFIT**)[20] will be funded under the access arrangement (by being included in the regulatory capital base). The NFIT seeks to ensure that only efficient investment which benefits all users of the network is recovered through regulated tariffs. Any augmentation investment which does not meet the NFIT will need to be funded by the customer seeking connection. Grouping customers together to develop a solution increases the potential for costs in excess of the NFIT to be funded by a number of access seekers and the project is therefore more likely to proceed.

The current AQP only appears to consider the scenario where an augmentation is undertaken and how the capacity from that augmentation is allocated to customers in the CAG. It does not appear to consider how a constrained connection can be shared between multiple customers. In any case it certainly does not set out the processes for such an arrangement.

[20] To meet the NFIT, expenditure must be demonstrated to be efficient <u>and</u> either is expected to be recovered through incremental revenue, provides a net benefit that justifies the approval of higher reference tariffs or is necessary to maintain the safety or reliability of the network or its ability to provide contracted covered services.

The Authority notes that the AQP retains the first come first served principle to deal with situations where a joint solution does not meet the requirements of the whole CAG. Clause 24.6A (c) of the AQP states that where the sum of the *preliminary acceptance* by *applicants* within a *competing applications group* exceeds the *capacity* of the proposed *works*, Western Power may make *access offers* to *applicants* in the order of the *priority date* of *applications* until there is no more *spare capacity*.

Applying the first come first served principle to determining which CAG members can be offered a constrained connection would be more straightforward and consistent with the current AQP than the more complex processes Western Power is considering.

As noted above, Western Power's proposed NCT solution does not appear to be contemplated in the current AQP. The Authority notes the Code also requires the AQP to facilitate the operation of the Market Rules. If, circumstances have changed since the AQP was approved in 2012, or the AQP does not adequately set out the processes Western Power is proposing to follow, the Authority recommends that Western Power review the AQP as soon as possible and propose revisions to the Authority for approval.

It is also unclear to the Authority why the proposed NCT does not have implications for the Technical Rules. The Authority considers a review is needed to ensure the Technical Rules are not affected by the introduction of Western Power's proposed NCT.

Western Power notes the difficulties in sourcing funding to overcome potential constraints that may bind for a small number of hours in a year. In relation to the funding of network augmentation, as noted above, investment which meets the NFIT can be rolled into the regulatory asset base and therefore recovered through regulated tariffs. For example, the Authority notes that the NFIT application put forward by Western Power (and approved by the Authority in January 2012) for the Mid West Energy Project (Southern Section) included the benefit of lower energy prices from new windfarms as one of the factors underpinning the investment. This clearly shows that, where it can be demonstrated that there is a net benefit to those who generate, transport or consume electricity, the required augmentation can be funded through the regulatory process. Providing the NFIT is properly applied, the Authority considers investment required to augment the network efficiently will be adequately funded.

Balancing Market

Key findings

The new Balancing Market has delivered significant improvements and increased the competitiveness of the WEM. The IMO's list of planned Balancing Market refinements is comprehensive and would deliver additional improvements to the WEM. Further progress of these refinements awaits the outcome of the EMR.

If the Government decides to retain the current market design, priority should be given to those developments which have the greatest impact on removing barriers and improving incentives for generators to fully participate in the market. These would include reducing gate closure times and improving the accuracy of forecast loads and prices.

A review of the STEM should also be a high priority to ensure it provides net benefits for the transaction costs incurred by Participants and the administrative effort required to support it.

Clarity regarding the future market design is needed as soon as possible to enable these developments to progress.

Original market design

When the WEM was established in 2006, its design was based on a conservative approach which aimed to minimise the risks associated with the reform process by undertaking an evolutionary rather than revolutionary approach to market design. The original WEM design took account of:

- The fact that the SWIS is a small, geographically isolated system which is not interconnected with any other electricity jurisdiction;
- A desire to reduce risk and encourage private investment;
- A desire to maintain, as much as possible, existing Bilateral contracts;
- The initial industry structure was characterised by a small number of market participants, with limited diversity and number of generating plants;
- A number of existing participants were small firms;
- The significance of the reliability objective to Government; and
- Minimising the implementation and operational costs of the wholesale market while maintaining its efficiency and effectiveness.

The original market model consisted of:

- A bilateral contract market;
- A binding day ahead Short Term Energy Market (STEM);
- Balancing and ancillary services mechanisms; and
- A Reserve Capacity Mechanism (RCM).

Until 30 June 2012, Synergy[21] was the sole provider of balancing services and the WEM operated under a 'hybrid' dispatch design. Under this design, IPPs were required to commit and dispatch their facilities to meet their respective Resource Plans, i.e. 'net dispatch', whilst Synergy's generation portfolio was dispatched to meet residual requirements in the market under the 'gross dispatch' regime. IPPs were penalised through the application of charges for deviations from their Resource Plans except when the facilities were dispatched by System Management for system security reasons. System Management maintained overall system security by scheduling and dispatching Synergy's facilities, calling on IPP facilities only when Synergy's balancing capability was stretched.

New Balancing Market

Efforts after market commencement were initially focussed on refining the Market Rules to ensure that they worked as intended. Following this work, attention shifted to focus on future Market development. As set out in the Market Rules Evolution Plan Issues Paper in June 2009, the original market design was considered to lack mechanisms to handle unexpected events between the clearing of the STEM and real time dispatch, and that this appeared to create a number of issues which impacted on both Synergy and other market participants:

- Under the day ahead STEM mechanism, balancing prices did not always reflect the final dispatch and this was impacting on Synergy as the balancing generator during the one day lag;
- IPPs did not have the flexibility to choose between generating energy from their own units or purchasing from another generator within the dispatch day, without incurring penalties for deviating from their resource plan; and
- There was also a desire to allow IPPs to contribute towards balancing more effectively where this would result in lower supply cost.

After further consultation, Market Participants ranked an improved balancing mechanism as the number one priority. A Market Rules Evolution Plan was developed by the IMO and a new competitive Balancing Market was designed, with stakeholder involvement, over the next few years.

The new competitive balancing market was introduced on 1 July 2012, enabling all generators to offer balancing services. Transitional arrangements applied until 5 December 2012 when all new systems became available. Balancing facilities are defined as Market Generators (other than Synergy's) scheduled and non-scheduled generating facilities. The objectives of the Balancing Market are to:

- Enable all balancing facilities to participate in the Balancing Market;
- Dispatch the lowest cost combination of facilities made available for Balancing;
- Establish a balancing price which is consistent with dispatch;
- Seek to ensure that timely and accurate balancing pricing and quantity information, including forecasts, and system security information, is provided to all Market Participants; and

[21] At the time, prior to their merger in 2014 (discussed below in this Report), Verve Energy was the government owned electricity generation corporation and Synergy the retailer. For clarity and consistency with the current merged structure, Synergy here refers to both generation and retail functions.

- Seek to ensure that timely and accurate information relevant to the operation and administration of the Balancing Market is provided to Rule Participants.

An assessment commissioned by the IMO and undertaken by Sapere Research Group (**Sapere**) prior to the new market commencing identified the following directly measurable benefits:

- Lower cost energy balancing capacity as a result of lower cost IPP plant being dispatched before Synergy plant in the merit order.
- The shorter gate closure and ability of IPPs to respond to events would increase the capacity bid into the balancing market with the benefit being that the additional capacity would result in lower clearing prices in some periods.
- Encourages and allows generators to return to the market earlier from planned outages in the event of major pricing events such as another generator tripping out unexpectedly.
- Reduces the amount of cycling of baseload plant.[22]

The Balancing Market requires submission of Balancing offers for all generators, apart from those on an approved planned outage or forced outage. Balancing offers include quantity and price pairs specifying the capacity at which a Market Participant is willing to be dispatched. Prices offered must be within the Price Cap (i.e. between the maximum and minimum STEM price) and must not be in excess of the Market Participant's reasonable expectation of its short run marginal cost (**SRMC**) when such behaviour relates to market power. Market Participants other than Synergy are able to revise their offers up to 2 hours prior to the Trading Interval commencing to reflect changes in market conditions. Synergy has further restrictions and different gate closure times.

Under the new Balancing Market, Synergy has continued to be able to offer its facilities on a portfolio basis and is treated as a single Balancing Facility. Synergy is able to offer its portfolio in 35 tranches and IPPs can offer 10 tranches for each scheduled generating facility. Intermittent generating units can only be offered as a single tranche and offers include price and estimated output. Synergy is also able to offer a facility on a stand-alone basis consistent with IPPs but, to date, has not.

The IMO uses the balancing offer submissions to develop the Balancing Merit Order (**BMO**) which is used to determine which facilities are dispatched by System Management.

Any deviation Market Participants are required to make from their Net Contract Position (**NCP**)[23] is treated as a Balancing Market transaction. Market Participants are paid the Final Balancing Price on their Metered Balancing Quantities (**MBQ**), i.e. the difference between their NCP and actual generation or load. This differs from the NEM where settlement is based on total generation and load, i.e. the Balancing Market is gross pool dispatch but net settlement.

System Management is required to dispatch all participants based on the BMO. Any generator that is dispatched or curtailed out of merit by System Management receives compensation. A generator receives Constrained On compensation if more energy is dispatched from that generator than indicated by its Balancing Submission offer price compared to the Balancing Price (e.g. in the case of a forced outage when a generator covers for lost generation). A generator receives Constrained Off compensation if it was

[22] Baseload plant are designed to run more or less at a constant load level and incur additional costs if required to turn off and then restart in response to changes in demand.

[23] NCP is a Participant's bilateral contract position net any energy traded on the STEM.

not or could not be dispatched by System Management despite having a Balancing Submission offer price lower than the Balancing Price, due either to system related reasons (e.g. a transmission line outage) or non-system related reasons (e.g. if the system load forecast is too low System Management may fail to dispatch a generator that is later found to have been in merit). Compensation payments are funded by all Market Customers in proportion to their share of total energy consumption.

Review of Balancing Market

In its 2013 Report, the Authority found that generally stakeholders were happy with the new arrangements, though some noted further time was needed to make a proper assessment.

As identified in the Compliance Audit Reports, improvements were required in dispatch processes and market information. The Authority also noted the following:

- Significant volumes were still being offered at the minimum and maximum price cap levels, which may indicate bidding behaviour was not being incentivised fully to result in the most efficient outcomes for the market.
- The requirement for a Market Participant not to bid in excess of its reasonable expectation of SRMC when such behaviour relates to market power is key to ensuring the lowest cost generation is dispatched. The Authority noted it would continue to develop its assessment of SRMC and the monitoring tools it uses with the IMO to ensure the SRMC requirement is being complied with.
- Market Participants receive constrained on or constrained off payments if they are dispatched or curtailed out of merit. Payments can arise due to network constraints or network outages. The Authority proposed to review further whether the current arrangements are working effectively to ensure the most efficient dispatch and minimum cost to the market.
- Synergy has been able to bid on a portfolio basis since market commencement. This was a pragmatic approach when it was the sole provider of balancing energy. However, this approach reduces the transparency of Synergy's bids in the balancing market and may be impacting on the ability of the Balancing Market to deliver the most efficient outcomes for the WEM.

A number of potential rule changes were under consideration which would further refine the operation of the WEM. These included:

- Removing the requirement to submit Resource Plans;[24]
- Potential changes to the STEM, including changes to timeframes and making participation optional;
- Changes to gate closure times; and
- Changes to the timeframes and requirements for Bilateral Submissions.

The IMO's submission to the Authority's 2014 Discussion Paper notes a review of the STEM is one of the highest priority issues in the current Market Rules Evolution Plan. The IMO notes that, 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. The IMO notes that, as the Balancing Market has transformed the

[24] These were required prior to the new Balancing Market commencing as they set out the generation schedule for IPPs. IPPs were required to operate in accordance with their Resource Plan and Synergy provided all balancing requirements. Under the new Balancing Market, dispatch of generation is based on the BMO. Hence Resource Plans now provide little, if any, purpose.

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 as provision of platforms to support longer term (e.g. weekly or monthly) trades.

The Authority considers the new Balancing Market has delivered significant improvements and increased the competitiveness of the WEM. Work undertaken by the IMO in conjunction with industry has identified further improvements which can be made. The Authority considers the IMO's list of planned refinements of the Balancing Market is comprehensive and will deliver improvements to the WEM. However, further progress of these refinements awaits the outcome of the EMR.

If the Government decides to retain the current market design, the Authority considers priority should be given to those developments which have the greatest impact on removing barriers and improving incentives for generators to fully participate in the market. For example:

- Improve the timing and content of Dispatch Advisories issued by System Management so they provide sufficient notice and information of conditions to enable generators to respond appropriately;
- Reduce gate closure times;
- Improve the accuracy of forecast loads and prices;
- Require Synergy to offer each generation facility on a stand-alone basis, rather than the current portfolio arrangement; and
- Ensure other aspects of the WEM do not dis-incentivise participation in the Balancing Market (e.g. the basis of allocation of spinning reserve costs and penalty capacity charge refunds in peak times).

The Authority also considers a review of the STEM should be a high priority to ensure it provides value for transaction costs incurred by Participants and the administrative effort required to support it.

Clarity regarding the future market design is needed as soon as possible to enable these developments to progress.

LFAS Market

Key findings

LFAS prices were high when the new LFAS market commenced in July 2012. Although prices have subsequently reduced, they remain significantly higher than for similar services in the NEM.

Considerable effort has been made by the IMO and System Management to better understand the LFAS requirement and this work is ongoing. The IMO's list of planned refinements is comprehensive. It has also identified improvements in other areas of the Market Rules (e.g. reduced gate closure times) which would facilitate better LFAS outcomes.

Whilst there are a number of short term opportunities currently being worked on, more significant longer term changes have been deferred until the outcome of the EMR is known.

In addition to pursuing those developments which will assist in reducing costs, high priority should be given to applying the principle of user (or causer) pays as this will increase the incentives for cost reduction.

Clarity regarding the future market design is needed as soon as possible to enable these developments to progress.

New LFAS Market

LFAS provide the primary mechanism to ensure that supply and demand are balanced in real-time. Load following accounts for the difference between scheduled energy and actual load. Load following resources must have sufficient ramping capability to adjust their output to match system load between scheduling steps, as well as maintain the system frequency. Load following can only be provided by units operating under Automatic Generation Control (**AGC**). LFAS Up refers to the service of adjusting output upwards to meet demand and LFAS Down refers to the service of adjusting output downwards when demand falls.

LFAS has been provided since the inception of the WEM, with Synergy (as Verve Energy until 2014) being contracted as the sole provider of this service until 30 June 2012. Up to this date, payment for the provision of LFAS was based on a proportion of the Marginal Cost Administered Price (**MCAP**), which was in turn based on prices in the previous balancing mechanism. A new competitive LFAS market was established on 1 July 2012, with the key elements of this new market being market-derived prices rather than administered prices, and participation open to all IPPs in addition to Synergy.

The LFAS requirement is set by System Management and must meet the frequency keeping standard specified by clause 3.10.1 of the Market Rules. The current requirement for both LFAS Up and LFAS Down is 72 MW. Although permitted under the Market Rules, the requirement set by System Management does not currently change between Trading Intervals.

The total cost of providing LFAS is passed on to Market Customers and Non Scheduled Generators, based on the demand of the Market Customer and the output of the Non Scheduled Generators, as a proportion of the total quantity consumed or generated.

The highest volatility in prices and the highest average price for both LFAS Up and LFAS Down occurred at market commencement.

Possible reasons for this include:

- Lack of competition;
- The carbon price impact on SRMC as at 1 July 2012, resulting in higher prices;
- Potentially the previous administered price understated the cost of providing LFAS.

Prices reduced following the introduction of Synergy's High Efficiency Gas Turbines (**HEGTs**) in September 2012. Further price reductions followed a decrease in the LFAS quantity requirement in July 2012 and February 2013, and NewGen's entry to the market in February 2013.

The LFAS requirement has remained unchanged over the 2013/14 period, no additional facilities have provided LFAS and no new participants have entered the market. Price variability remains but maximum prices have been consistently lower than the initially high levels seen at market commencement.

Review of LFAS Market

A number of submissions to the Authority provided comment on the LFAS market. Key points are summarised below.

The IMO's submission provides considerable detail regarding the work it is doing with System Management and the industry in relation to LFAS.

The IMO lists a number of opportunities which have been identified to reduce LFAS costs in the short term. It also notes a number of other options identified with the potential to significantly reduce LFAS costs, but these are considered to be dependent on the outcomes of the EMR as they would require more significant, longer term changes. These options include:

- 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);
- 'causer pays' allocation of LFAS costs.

System Management's submission notes that the cost of LFAS increased significantly after the introduction of the LFAS market on 1 July 2012, and has provided some analysis comparing cost and volumes with the NEM. It notes the cost per MW each hour is twenty times greater than the NEM ($40 versus $2.50) and suggests a key reason for this is the relative lack of competition in the WEM compared to the NEM, as currently only two market participants provide the service with one participant almost exclusively setting the market price. System Management notes it is working with two additional market participants to commission AGC, which will enable the facilities to offer LFAS if they wish.

System Management further notes that LFAS quantities are half that of the NEM yet total energy is one tenth. It considers the overriding factor behind these relatively higher volumes in the WEM are gate closure and dispatch cycle times – WEM volumes are set 6 to12 hours in advance, whereas NEM LFAS volumes are set 5 minutes in advance by the co-optimised dispatch engine. It believes a move to shorter gate closure and dispatch cycle times would have a dramatic effect on required LFAS volumes and would also increase competitive pressure on prices.

Community Electricity's submission notes there appears to be a difference between the quantity being paid for and the quantity actually dispatched due to the interaction with other ancillary services. It considers the focus should be on reviewing the actual LFAS quantity and how to relate it to the quantity being paid for.

Community Electricity also notes statements previously made by the ERA when determining charging parameters for the provision of Load Rejection Reserve (**LRR**)[25] services that there was no evidence that provision of LRR service incurred a cost not already recovered elsewhere. It questions whether this might also apply to the cost of LFAS and Spinning Reserve.

The IMO's submission notes potential issues in relation to the allocation of Load Rejection Reserve Service (**LRRS**) costs. Currently the costs for LRRS are assessed to be zero. However, modelling work requested by Western Power to assist in assessing connection requirements for a large customer suggest that the cost could increase significantly. Current rules allocate LRRS costs across all Market Participants based on consumption. The IMO queries whether this approach will continue to be appropriate if future costs were to increase due to specific connections, and recommends that the ERA consider whether the current arrangement for the allocation of LRRS costs is the most efficient option.

The Authority noted in the 2013 Report that the introduction of competition in LFAS provision and the increased transparency resulting from it had provided significant benefits in focussing attention and increased understanding of the factors driving LFAS and ancillary service costs generally.

The Authority noted a number of potential further reforms to the LFAS market had been identified for further investigation, including:

- Shorter gate closure times;
- Introduction of a causer pays model;
- Better intermittent generation forecasting;
- Reducing the LFAS requirement in some Trading Intervals;
- Reviewing the performance standard being used by System Management for frequency stability, particularly given that it is higher than the standard required under the Technical Rules;
- More frequent dispatch intervals; and
- Opening up other Ancillary Services to competition.

[25] System Management are required to submit the charges for providing LRR services to the ERA every three years for approval. The most recent decision was published in March 2013 and determined that the cost was nil, consistent with System Management's application.

There are several possible reasons why the NEM's load following requirement can be kept relatively low. In the NEM, the system operator apportions load following costs on a 'causer pays' basis, which provides an incentive for generators and loads to minimise the extent to which they allow their output or demand to vary from expected levels. The system operator also adjusts the load following requirement to different levels depending on the anticipated demand for load following. Another important factor appears to be the fact that the NEM has a 5 minute dispatch cycle, whereas WEM dispatch is determined on the basis of half hour forecasts. Shorter dispatch cycles enables a better match of demand and supply, thus reducing the size of the shortfall/surplus that load following plant must balance. The NEM also co-optimises energy and frequency control ancillary services (**FCAS**, equivalent to LFAS for the WEM) in its dispatch engine which would further reduce costs compared with the WEM.

The Authority recognises that considerable effort had been made by the IMO and System Management to better understand the LFAS requirement and that this work is ongoing.

Since the Authority's 2013 WEM review, the IMO has undertaken its required five yearly review of ancillary services with the final report published on 6 November.

A study prepared for the IMO by its consultant noted the following:

> The cost of frequency control in the WEM is higher than those in any other market studied. This is particularly due to the WEM's LFAS costs. ROAM found that regulation requirements vary significantly depending on the nature of a system and that the particular nature of the market services, structure and also the type of generation assets available heavily dictate the necessary regulation requirements. The WEM's relatively small size, lack of inter-connectedness, load concentration and absence of significant hydro generation in particular are all factors contributing to high regulation (LFAS) requirements and therefore high LFAS costs. ROAM has made a number of recommendations for actions that would help to minimize LFAS requirements based on international experience and review.

The ancillary services review has provided further insight into LFAS costs and ancillary services generally, which should enable improvements to be made in arrangements for all ancillary services.

The Authority considers there is already a good understanding of improvements which could be made to the LFAS Market. The Authority recognises that the IMO's list of planned refinements of the LFAS Market is comprehensive. It has also identified improvements in other areas of the Market Rules (e.g. reduced gate closure times) which would facilitate better LFAS outcomes. Whilst there are a number of short term opportunities currently being worked on, options requiring more significant longer term changes have been deferred until the outcome of the EMR is known.

Currently LFAS costs are spread proportionally across all to Market Customers and Non Scheduled Generators, based on the demand of the Market Customer and the output of the Non Scheduled Generator. In addition to pursuing those developments which will assist in reducing costs, the Authority considers that a high priority should be given to applying the principle of user (or causer) pays as this will increase the opportunities and incentives for cost reduction.

Sustained outages

Key findings

Despite significant transmission outages during the 2013/14 year, generally system security has been maintained. However, improvements could be made to streamline the process for managing outages and ensuring costs are minimised.

The criteria System Management is required to use under the Market Rules when dealing with forced network outages may not always result in the lowest overall cost. Outcomes could be improved by:

- Providing System Management with visibility of prices
- Changing rules around use of Demand-Side Management (**DSM**) to provide a more flexible method for dealing with localised outages

System Management should retain responsibility for ensuring power system security and, providing it has access to all the relevant information, is best placed to ensure the right balance between system security and cost.

Allocating constrained on/off compensation and ancillary service costs on a causer pays basis would provide better incentives for efficient market outcomes. Ensuring Western Power faces all costs arising due to transmission constraints (including those currently paid by market customers) would provide better signals for network planning and investment.

System Management's decisions around planned outages should take account of market impact as well as system security.

The proposed Rule Change to improve incentives for generator availability (RC_2013_09) should be progressed as soon as possible.

Constraint payments

During the 2013/14 year there have been a number of significant outages, primarily affecting the Southern region. As a consequence it has been necessary for the Muja AB plants owned by Vinalco Energy[26] to be dispatched out of merit for considerable periods of time, resulting in significant Constrained On payments being passed through to Market Participants.

The Authority notes that there has been very little impact on supplies to customers despite the major transmission asset failures at Muja. Although there are improvements which could be made, it is important to recognise that system security has been maintained.

Alinta's submission notes significant constraint payment costs have been incurred by Market Customers as a consequence of the need to dispatch Vinalco units to maintain power system security. The Authority is currently undertaking an investigation referred to it

[26] Vinalco Energy is 100 per cent owned by Synergy.

by the IMO in relation to prices offered by Vinalco Energy during March and June 2014. These investigations are separate from the Authority's WEM review but are likely to provide useful insight regarding whether the current rules are adequate for dealing with such events.

In relation to System Management's criteria for dealing with forced outages, the IMO's submission notes that, in some very rare circumstances, it is possible that the priority System Management must follow may not result in dispatch of the lowest cost energy. It also notes that any part dispatch of DSM to assist with a specific network constraint can be problematic under the current Market Rules, which do not consider the geographic locations of the associated loads of a DSM provider.

The IMO notes that 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.

The IMO's view is that the current constraint payment mechanism is only designed to address short term interruptions to normal dispatch. It considers 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) due to the method used to calculate constrained on volumes (i.e. there is a shortfall in the volumes between what is actually dispatched and what is assessed as the constrained on quantity);
- Distorts the forecast BMO and the forecast Balancing Price as these do not reflect the constrained on generation; and
- Imposes significant and unpredictable costs on Market Participants.

The IMO considers the Balancing Market design assumes that any extended network constraint will be managed through a Dispatch Support Service Contract (**DSSC**), which is procured by System Management and paid for by Market Participants, or a Network Control Services Contract (**NCSC**), which is procured by Western Power and recovered through future network tariffs under the Access Arrangement. However, it has identified the following issues in relation to DSSCs and NCSCs:

- The criteria for when a DSSC or NCSC may and/or should be employed are not well-defined;
- The distinction between a DSSC and an NCSC 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;
- For DSSCs the costs are allocated to Market Participants – who are unable to provide an effective response – rather than to Western Power, the party that is best able to assess the risks involved and manage the cause of the issue.

As noted in its submission, System Management is responsible for procuring Ancillary Service contracts, which include DSSCs. It also considers there is ambiguity in the current WEM Rules about when such contracts should apply.

The Authority considers the criteria System Management is required to use under the Market Rules when dealing with forced network outages may not always result in lowest cost energy supply. In particular, the criteria does not directly take account of costs and generally System Management has no visibility of prices. Although System Management has access to the merit order as expressed in the BMO, visibility of actual prices would better ensure that the lowest cost option is employed. The rules around use of DSM could also be improved to make it a more flexible method for dealing with localised outages.

However, in the case of the Muja outage, on the assumption that operating the Vinalco Energy units was the only option available, and assuming that it was required to bid at SRMC, it is unclear to the Authority how a contracted service through either a DSSC or NCSC could have resulted in a lower cost.

The Authority notes that the costs of constrained on generation are smeared across all Market Customers. This is also the case for the majority of Ancillary Service costs incurred to maintain system security (e.g. DSSC, LFAS). The only exception to this is the costs of spinning reserve, which are allocated to generators based on their capacity.

The Authority considers that allocating constrained on/off compensation and ancillary service costs on a user (or causer) pays basis would provide better incentives for efficient market outcomes.

The Authority notes that the Service Standard Adjustment Mechanism (**SSAM**) in Western Power's access arrangement includes a measure of circuit availability. The failure of the Muja transformers has resulted in a SSAM penalty; however, Western Power has not directly faced the costs arising in the market due to the out of merit dispatch of Vinalco. The Authority considers investment incentives for Western Power would be improved if ancillary service costs and constrained on/off compensation was allocated on a user (or causer) pays basis.

The Authority recommends, subject to the outcomes of the EMR, that changes be made to allocate ancillary service costs and constrained on/off compensation on a causer pays basis as soon as possible.

However, the Authority does not consider that requiring Western Power to directly enter into contractual arrangements as proposed by some stakeholders would result in better outcomes. The Authority considers System Management should retain responsibility for ensuring power system security and, providing it has access to information on prices, is best placed to ensure that the most cost effective options are used. If such costs are then passed on to the causer (Western Power in this case), it would then be incentivised to invest appropriately or take whatever other action it could to reduce these costs.

Timing of planned outages

Community Electricity's submission raised concerns in relation to Synergy's baseload outages. The Authority's 2012 Report to the Minister noted potential perverse market incentives may have led to a number of Synergy's units being unavailable for extended periods of time. These units had been assigned Capacity Credits and received full payment for these Capacity Credits, even though they were on planned outage for extended periods. The Authority was particularly concerned that planned outages coincided with times of tight supply, leading to price spikes. Moreover, the facilities on planned outage included a number of baseload generators and mid-merit gas units, which would typically have resulted in lower clearing prices had they been dispatched.

In the 2012 Report, the Authority identified three possible causes of the high rates of planned outage that had been observed in the WEM during the previous few years. These were:

- The design of the reserve capacity refund payments that are paid by generators when generation facilities are unavailable;
- A limited ability of the IMO to prevent poorly performing generators operating in the market; and
- Rules limiting the ability of the IMO to monitor and enforce performance standards.

The Authority considered that incentives to maximise plant availability in the market needed to be reviewed and supported the IMO's undertaking of a review of current generator availability and incentives to improve performance.

Prior to the EMR, a Rule Change Proposal was developed (RC_2013_09) which would have addressed much of the Authority's concern and led to improved outcomes.[27] However, the Authority notes that the Rule Change did not proceed due to commencement of the EMR. Subject to the outcome of the EMR, the Authority recommends that this Rule Change should be revisited as a high priority to improve incentives for generator availability.

In relation to the criteria System Management must follow when approving Planned Outages, the IMO's submission to the Authority's Discussion Paper notes the criteria currently prescribed in the Market Rules do not include any explicit consideration of commercial impacts on the WEM, and their application may in some circumstances contribute to short-term increases in energy prices.

Similar to the discussion in relation to improving System Management's ability to choose the best option in the case of forced outages, the Authority agrees that System Management's decisions around planned outages should also take account of market impact. However, the need for this would be reduced if generators had better incentives to be available.

[27] The Rule Change Proposal included:

- permitting the IMO more flexibility in assigning a quantity of Certified Reserve Capacity to Scheduled Generators displaying excessive outage rates over a 36 month period;
- specifying a range of factors to be considered by the IMO in making its decision, adding certainty, structure and transparency;
- progressively tightening the combined planned and forced outage rate thresholds that trigger this clause from 30 per cent to 20 per cent over five years, commencing in 2016, with provision for review in 2018;
- imposing an upper limit on the number of Trading Intervals in any 36 month period for which a generator can claim a reduction of its Reserve Capacity Obligation Quantities (**RCOQ**) due to planned outages;
- granting discretionary power to the IMO to require both performance and performance improvement reports from Market Participants concerning Facilities with excessive Planned Outage rates, regardless of the availability of total system capacity;
- deleting a number of clauses that have become redundant due to the cap on Planned Outages for which a reduction in RCOQ quantities may be claimed.

Appendix 1 Public Submissions Received

Public submissions were received from:

- Alinta Energy
- Community Electricity
- Independent Market Operator
- System Management
- Western Power