GOVERNMENT OF WESTERN AUSTRALIA

Energy Transformation Taskforce

Foundation Market Parameters – Information Paper

August 2019

Table of Contents

1. Introduction

1.1 The Energy Transformation Strategy

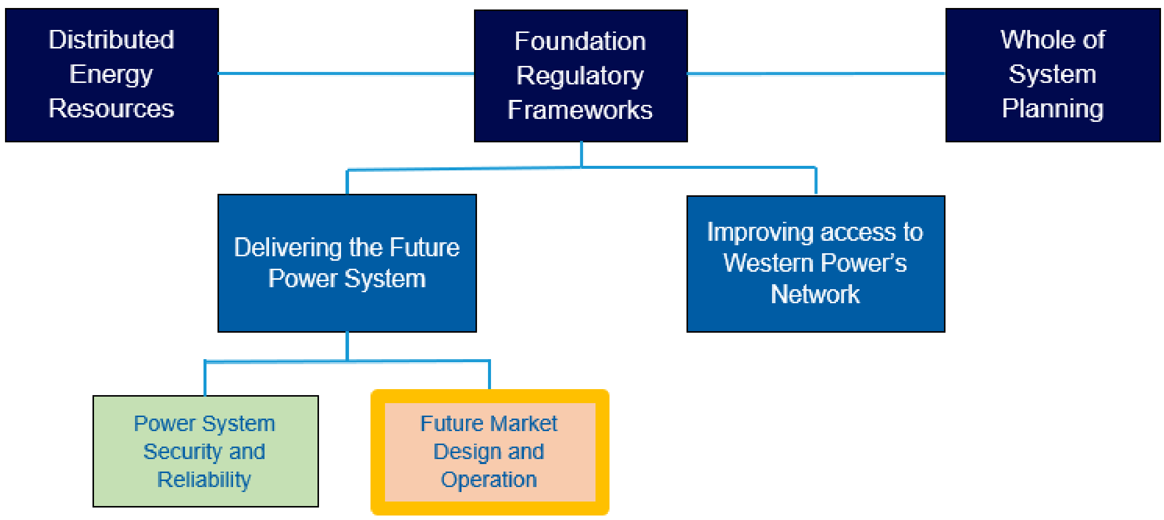
The energy sector is undergoing an unprecedented transformation in the way electricity is supplied and used. More households and small businesses than ever are installing solar photovoltaic (PV) and battery systems to control electricity bills. At the same time, large-scale renewable generators are supplying an increasing amount of power to the grid.

The intermittent, and in some cases, uncontrolled nature of these energy sources is presenting challenges to the security, reliability and affordability of the power system, particularly in the South West Interconnected System (SWIS).

To address these challenges, on 6 March 2019, the Hon Bill Johnston MLA, Minister for Energy announced the McGowan Government's Energy Transformation Strategy. This is the Western Australian Government's strategy to respond to the energy transformation underway and to plan for the future of our power system. The delivery of the Energy Transformation Strategy is being overseen by the Energy Transformation Taskforce (Taskforce), which was established on 20 May 2019. The Taskforce is being supported by the Energy Transformation Implementation Unit (ETIU).

The Energy Transformation Strategy is being delivered under three work streams: *Distributed Energy Resources*, *Foundational Regulatory Frameworks* and *Whole of System Planning*. This information paper, *Foundation Market Parameters*, has been prepared as part of the *Future Market Design and Operation* project of the Foundation Regulatory Frameworks work stream, as shown in Figure 1, below.

Figure 1: Energy Transformation Strategy work streams



The improvements to the WEM to be implemented under the Future Market Design and Operation project will address both urgent and evolving challenges and opportunities facing the SWIS as a result of the transition to a more intermittent and distributed supply mix.

More information on the Energy Transformation Strategy, the Taskforce and ETIU can be found on the Energy Transformation website at http://www.treasury.wa.gov.au/Energy-Transformation/.

1.2 Purpose and Scope

Significant modifications need to be made to the current design of the Wholesale Electricity Market (WEM) to meet the challenges posed by increasing levels of renewable generation, as well as capturing the opportunities created by change. The purpose of this information paper is to communicate the *foundation market parameters* selected by the Taskforce to define the new WEM, and associated changes to the market model, which will take effect on 1 October 2022.

A foundation market parameter is a fundamental design feature on which the more granular design of the market will be built. Market parameters have been developed, assessed and selected by the Taskforce based on the extent to which they:

1. support the WEM Objectives, as contained in the *Electricity Industry Act 2004*;
2. align control and responsibility for outcomes in such a way that the entities that are able to effect an outcome are required and empowered to do so;
3. avoid imposing unnecessary costs and complexity on electricity market participants;
4. take into consideration the current and future technical capability of individual generators and loads, and technologies that may function as both;
5. reflect the experiences of other comparable energy markets and current best-practice approaches to regulation in the energy sector;
6. include governance mechanisms to promote transparency and facilitate required market and power system evolution over time; and
7. consider practicality of implementation, including the usability of current systems and processes and extent to which changes will require amendment to primary legislation or other regulatory instruments.

Reforms proposed in the July 2016 paper prepared by the Public Utilities Office titled *Final Design Recommendations for Wholesale Energy and Ancillary Service Market Reform*[1] have been adopted by the Taskforce as a starting point for the development of the market parameters outlined in this paper. These July 2016 proposals have been reviewed by the Taskforce for their continued validity and relevance to the Energy Transformation Strategy, given the disruption to the electricity supply chain model that has developed over the last three years.

The foundation market parameters outlined in this paper reflect industry consultation undertaken following the release of the July 2016 paper and through the Market Design and Operation Working Group (MDOWG) in February 2019.[2] Stakeholder feedback has been included in this paper where relevant. Stakeholders will be able to comment on the detailed design of the new WEM arrangements during 2019 and Amending Rules resulting from the decisions of the Taskforce in early-2020.

Further questions or comment on this paper can be provided by emailing marketdesign.wg@treasury.wa.gov.au

1 Public Utilities Office, 2016, *Final Report: Design Recommendations for Wholesale Energy and Ancillary Service Market Reforms*, Available at: http://www.treasury.wa.gov.au/uploadedFiles/Site-content/Public_Utilities_Office/Industry_reform/Final-Report-Design-Recommendations-for-Wholesale-Energy-and-Ancillary-Market-Reforms.pdf

2 The MDOWG was a working group of the Market Advisory Committee and was chaired by ETIU. Minutes, agenda, and other meeting papers of the MDOWG are available on the Rule Change Panel website at: https://www.erawa.com.au/rule-change-panel-mdowg

2. The WEM – The case for change

2.1 Introduction

The power system is experiencing transformation because of changes to the mix of grid-connected large-scale generation technologies, consumer demand patterns, and growth in the penetration of Distributed Energy Resources (DER), such as solar PV and battery storage systems. Because of this transformation, the market systems, standards, obligations, and frameworks that underpin the operation of the WEM are unsustainable. Without changes to the market design and operation:

- electricity will not be dispatched at the least sustainable cost;
- the power system will be limited in its ability to accommodate greater penetration of intermittent renewable generators, including roof-top solar PV systems, while maintaining security and reliability;
- signals for timely investment in the power system will be muted;
- the ability of the SWIS to reduce carbon emissions and meet renewable energy obligations will also be limited; and
- costs for all power users will be higher than they might otherwise be.

The transformation of the power system, the impacts this has had on power system security, and the current limitations of market systems are discussed below.

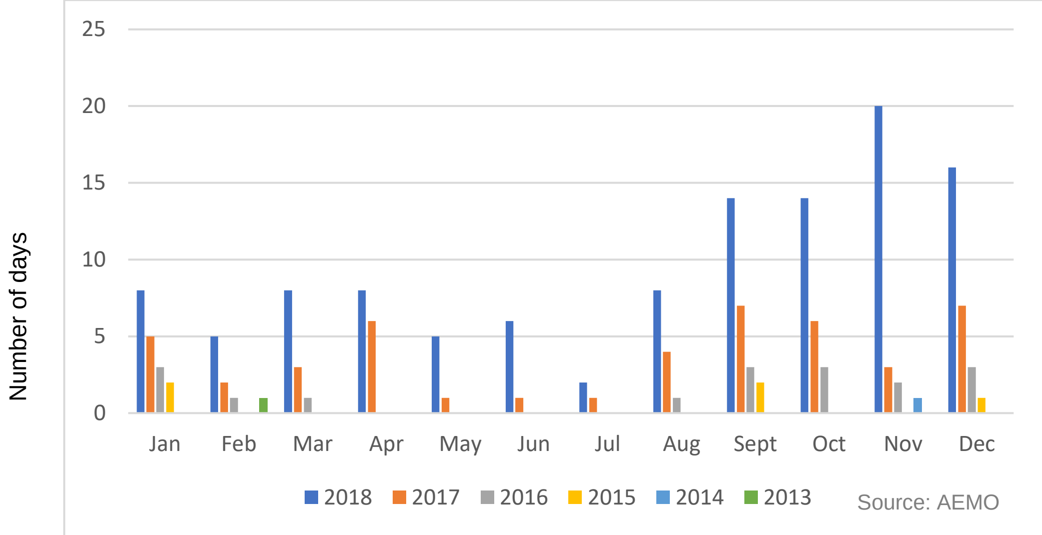
2.2 Transformation of the power system

Changes to customer behaviour

The demands customers place on the power system have changed significantly over the last decade. System peak demand has historically occurred in the late afternoon, driven by commercial and industrial users' demand coinciding with the ramp up of household use, and then tapering-off into the evening. Now, in the middle of a typical mild spring day demand is no longer at peak levels due to the increasing output of solar PV systems on both homes and businesses. At the same time, generation ramping requirements in the late afternoon and early evening are growing steeper as output from solar PV systems diminishes with falling solar radiance and homes switch on their air-conditioners. This transition will require changes to the design of the WEM in order to maintain system security and incentivise the right kinds of investment in the power system.

The speed of this transition is demonstrated by the increasing number of days where daytime (8:00 am to 7:30 pm) demand is lower than overnight (8:00 pm-7:30 am) demand; 46 days in 2017 compared to 114 days in 2018. As shown in Figure 2, these trends have continued, largely because of ongoing customer investment in DER and improvements in energy efficiency.

Figure 2: Days where peak daytime demand is lower than overnight demand



Challenges posed by large-scale intermittent generation

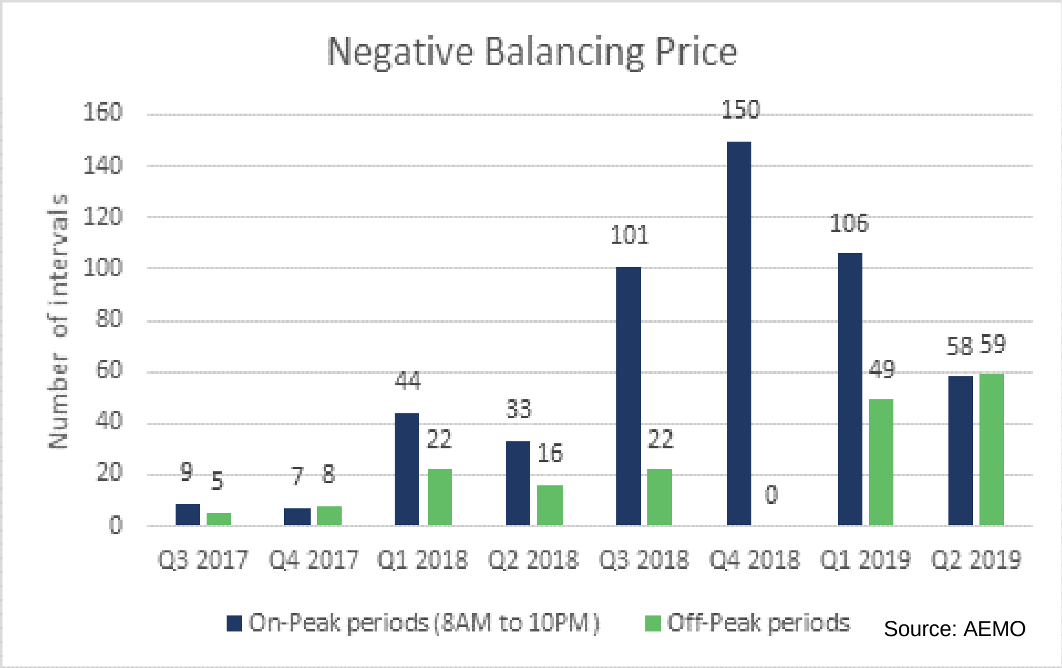
Changes to our large-scale generation mix are also resulting in challenges for the management of the power system. While overnight demand has remained low relative to peak demand over the last decade, wind power has increasingly displaced output from generators with higher fuel costs (the marginal cost of generation for wind power is effectively zero). In the absence of changes to the WEM, this situation will continue to require controllable generation to be dispatched 'out-of-merit' to maintain power system security, displacing lower-priced wind output at significant cost to customers.

Customer behaviour and large-scale generation - Effect on the market

The increasing effect on the electricity market of renewables and DER-driven low daytime demand can be observed in the number of trading intervals where prices are negative. The October to December quarter of 2018 set a record for the highest number of intervals with a negative Balancing Price during on-peak periods on record, with 150 negative price intervals. This compares with the same quarter of 2017, where negative Balancing Prices were observed in only seven trading intervals, as shown in **Figure 3**.[3] The trend of increasing occurrences of daytime negative Balancing Prices has continued in Q1 and Q2 2019, with 106 and 58 intervals clearing at a negative price during on-peak periods, respectively, compared with 44 and 33 intervals during the same quarters in 2018.

[3] Data on the frequency of negative pricing intervals is available on the Australian Energy Market Operator website at: www.aemo.com.au.

Figure 3: Number of trading intervals with negative Balancing Prices



In the absence of changes to the WEM and its underpinning frameworks, this continuing trend has the potential to challenge the technical operation and continued viability of conventional generators. While still required in order to maintain system security, these generators may increasingly be required to generate below efficient levels, temporarily power down, or cycle up and down in a way that is inconsistent with their design specifications.

2.3 Market system limitations

Complex Information and Communication Technology (ICT) systems are required to schedule and dispatch generators in alignment with customer demand and the security and reliability needs of the power system. These systems – with ongoing updates – have generally performed well since the start of the market in the SWIS. However, the ICT systems that underpin the operation of the power system are now reaching the limits of their ability to efficiently respond to a transforming power system at the same time as reliably maintaining power system security and reliability under a constrained network access regime.

The management of fluctuating output from intermittent generators, roof-top solar PV systems, and emerging physical constraints in the network, have resulted in the Australian Energy Market Operator (AEMO) increasingly relying on manual intervention to maintain power system security. Manual intervention is costly, as more energy is dispatched from more expensive generators than cheaper ones. This intervention also increases the risks of errors that could, inadvertently, result in supply disruption.

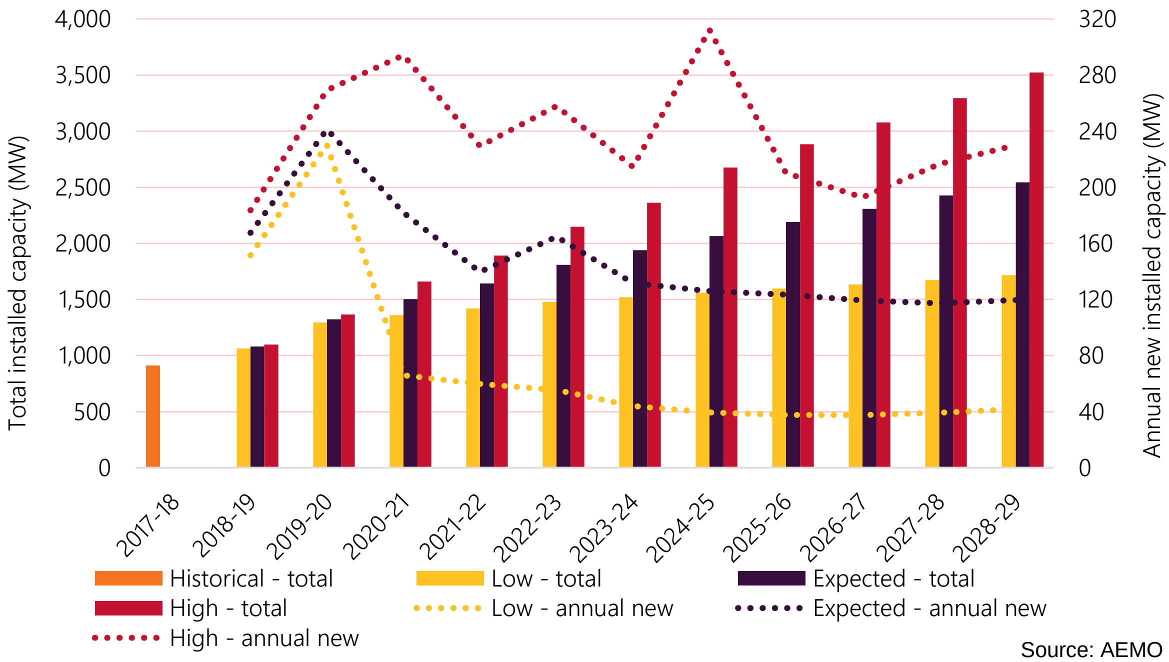
In addition to not reflecting the physical constraints of the network, the current ICT systems that determine the merit order for generation dispatch are not currently able to co-optimise across multiple markets (such as those for energy and essential system services). These limitations already result in generation being dispatched out of merit order, with increased costs being borne by customers.

Without full pricing information and tools to produce co-optimised solutions in the WEM, dispatch outcomes will not be efficient. Additionally, without greater automation, it is also difficult to ensure repeatable, consistent dispatch outcomes that can be communicated to the market within reasonable timeframes, or manage increasing challenges to system security.

2.4 Power system security and reliability challenges

The emergence of large-scale intermittent generation, changing consumption patterns, and uncontrolled customer-operated DER has challenged the framework of regulation and WEM Rules underpinning the maintenance of power system security and reliability. The changing generation mix means it can no longer be assumed that the inherent technical characteristics of conventional generators will continue to ensure the maintenance of system security.

Figure 4: Forecast installed behind the meter PV system capacity – 2018-19 to 2028-29[4]



Source: AEMO

Conventional thermal generators have traditionally provided important additional power system services, such as inertia, which assists with frequency control. However, conventional generators may not remain the most-available or most-economic source of providing such essential system services in future (often referred to as Ancillary Services). Changes to power system security and reliability standards and planning processes, as well as changes to the procurement and type of essential system services provided to the market, will be required to manage the system as changes to the generation mix, technology and customer behaviour continue.

[4] AEMO, 2019, *2019 Wholesale Electricity Market Statement of Opportunities*, June 2019, p. 26

3. Foundation Market Parameters

This paper outlines a set of foundation market parameters to improve the efficiency and transparency of the provision of energy and essential system services in the SWIS. A set of core market parameters have been identified that are essential to support the operation of constrained network access and improve the transparency and predictability of market outcomes in the WEM. These are supported by a set of secondary parameters that provide additional efficiencies to the operation of the WEM.

3.1 Core design parameters

There are three core and co-dependent design parameters that are essential to maximise the benefits of a constrained network access regime and address material inefficiencies in the current market design.

1. A security-constrained market design.

2. Facility bidding for all market participants.

3. Co-optimisation of energy and essential system services.

3.1.1 Security-constrained market design

The current WEM arrangements are premised on an unconstrained market design, reflecting the current network access model, where connecting generators have a right to full (unconstrained) access to the network, subject to making a contribution to the costs of any network upgrades needed to maintain full access for all connecting parties under normal operating conditions. The costs of these network upgrades can be prohibitively expensive, and Western Power has sought to avoid these by instituting ‘run-back’ and other interim schemes (such as the Generator Interim Access arrangement) that curtail the output of a generator in response to a network trigger, such as the power flow on a line exceeding a set thermal limit value. These arrangements are implemented outside of the operation of the market, although must be catered for in dispatch when they operate.

The market design assumes that electricity flows from generators to loads are unrestricted the majority of the time, with each generator able to output to its maximum capacity without threatening system security under normal operating conditions. Simple cost-based merit orders for generator dispatch are developed without any consideration of network constraints. When congestion does occur, AEMO is required to intervene and dispatch generators out-of-merit, dispatching more energy from a higher priced generator and less energy from a cheaper generator to alleviate the constraint. This is currently a manual process. A generator that is not dispatched due to a constraint but should have been (based on the merit order) receives ‘constrained-off’ compensation payments from the market.

An unconstrained market design is only workable if the level of network congestion is low. However, network constraints already bind regularly in the SWIS and are expected to increase in frequency with new generators seeking to connect. Some degree of congestion on the network is economically efficient, as it provides signals to investing parties as to where the utilisation of the existing infrastructure can be maximised. A security-constrained market design will support increased utilisation of existing network infrastructure by facilitating the efficient entry of new generators in a manner that efficiently manages the increasing complexity of network constraints.

The current market design fails to reflect the practical realities of the network and reduces market efficiency as a result of the following.

- A lack of transparent and timely information – forecast dispatch plans can be unreliable as they ignore the effects of congestion, discouraging active competition in the real-time markets. The existing, long gate closure periods further reduce the accuracy of forecasts and affect bidding behaviour.
- The current constraint payments mechanism for out of merit dispatch has been designed on the basis that constraints bind infrequently and only for short durations, and when network constraints require a generator to be constrained-on for an extended period, the current constrained-on payment mechanism may not adequately cover the generator's costs.
- Potential higher long-term costs to consumers, as the constraint payment mechanism is not sufficiently transparent to provide a long-term price signal to new entrants to locate their projects where they would deliver the greatest value.
- The necessity for extensive manual intervention to manage congestion, which increases the operational burden on AEMO and the likelihood of errors or inefficient dispatch.

Consequently, the adoption of a security-constrained market design that includes consideration of network constraints in the calculation of dispatch schedules is essential for the SWIS in order to maintain system security as congestion increases in the future. This will require replacing the existing market and dispatch systems used by AEMO to operate the WEM, as the current systems and processes will be incapable of managing the security of the network as the frequency of constraints increases over time.

In other security-constrained markets, the dispatch process is implemented using a constrained optimisation linear programming model that operates very close to real-time to satisfy demand for energy and ancillary services subject to the technical constraints of the network and generators. This dispatch algorithm solves a least-cost objective function that relies on all generators having equal rights in terms of their physical access to the network.[5]

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5 The Energy Transformation Taskforce is separately considering transitional issues faced by incumbent generators with firm access rights who may be affected by the changes to the framework for network access.

Adopting a security-constrained market design is fundamental to realising the benefits of the sustainable and efficient management of network constraints. It is expected to deliver the following benefits.

1. Transparent determination of the least-cost dispatch outcome for the market, accounting for generation offers and network conditions, and allowing market participants to respond, resulting in increased competition in the real-time market and a downward pressure on the energy price over time.
2. Greater automation in the calculation of network constraints, which improves network efficiency by allowing constraints to be set less conservatively without compromising system reliability.
3. Greater automation in the dispatch process, so that system security can be managed efficiently as the level of constraints increases, and the generation mix continues to change.

Stakeholders have previously indicated broad support for the adoption of a security-constrained market design.

A security-constrained economic dispatch market model will be implemented in the WEM

3.1.2 Market Participants will be required to bid and dispatch on a facility basis

In the current market, all independent power producers are required to offer into the Balancing Market on a facility basis, whereas Synergy offers on a portfolio basis. While Synergy has the option to offer into the Balancing and Load Following Ancillary Service (LFAS) Markets on a facility basis, it has not exercised this option to date.

This portfolio bidding approach is a historical legacy from the time when Synergy's portfolio (at the time held by the fully integrated Western Power Corporation) represented the vast majority of power stations in the market, and the dispatch controller was a branch of the same organisation.[6] However, progressive changes to the WEM, particularly the development of the Balancing Market to implement merit order dispatch of generating capacity, have largely obviated the case for portfolio bidding.

Market transparency and equity between market participants is reduced by the portfolio bidding approach, and effective market monitoring is impeded. The portfolio approach makes it impossible to discern the boundary between balancing and LFAS provision by generators, which in turn hinders the ability to precisely measure the quantity of LFAS capacity used. This arguably contributes to an overly conservative procurement of LFAS. Portfolio dispatch for

[6] System Management, now a part of AEMO, continues to act on behalf of Synergy to make decisions in real time regarding which generation facilities to operate, accounting for advice from Synergy that is provided periodically.

Synergy is currently performed by AEMO, when a similar service is not performed for other generators.

Facility bidding is required to enable the least-cost resolution of network constraints and the least-cost dispatch of generation in the market. A security-constrained market dispatch engine must forecast when network limits will be reached, requiring knowledge of the quantity of energy that will be injected and withdrawn at each location of the network and the prices of each generator in those locations in order to make optimised decisions. In contrast, portfolio bidding does not allow the clearing engine to inform the system manager where on the network energy from the Synergy portfolio should be generated or what its relative costs are, relying on AEMO to plan and implement dispatch using information in the form of dispatch guidelines from Synergy to decide where energy should be sourced from its portfolio.

In order to operate effectively, a co-optimised security-constrained economic dispatch will require Synergy to bid facilities consistent with the requirements placed on other parties. The progress of planned market improvements will be severely impeded without this, as individual facility prices are fundamental to making co-optimised dispatch decisions that trade-off energy and essential system services to manage security constraints on the power system in a least-cost manner. Further, facility bidding by Synergy will improve the transparency of dispatch decisions that allows the market to better respond to opportunities for new investment, particularly in the provision of essential system services, thereby helping encourage competition in their provision.

Synergy and independent power producers will be required to bid on an individual facility basis in the new market

3.1.3 Co-optimisation of energy and essential system services

It makes economic sense to co-optimise energy with available frequency control services – spinning reserve and load rejection reserve (known collectively in many markets as contingency reserve), and LFAS (known in many markets as (frequency) regulation). In the context of competitive electricity markets, co-optimisation refers to the process of simultaneously determining the overall least-cost dispatch outcome for both energy and essential system services. This process may involve complex trade-offs, particularly as the ability for a generator to provide essential system services will be influenced by its current production level.

Co-optimisation simplifies and reduces risks in the bidding process for market participants, allowing generators to offer simultaneously into energy and multiple essential system service markets, while being commercially indifferent as to which service they are dispatched to provide. Co-optimisation also enables the alignment of the ‘gate closure’[7] for essential system service markets with the energy market, providing market participants with the benefit of more accurate forecasts at the time they finalise their essential system service offers closer to the start of the trading interval. In turn, increased certainty of dispatch may mean generators

[7] ‘Gate closure’ is the nominated time by which market participants must have submitted the bids on which dispatch and other decisions by the Market Operator will be based.

respond with a reduced risk premium factored into essential system service offers, which over a period of time will place downward pressure on wholesale energy costs.

The SWIS, like many other electricity systems around the world, is experiencing challenges to ensure that there is sufficient provision of essential system services in periods of low demand, when rooftop solar PV output is greatest. During these periods it is important that energy and essential system services are co-optimised to preserve the flexibility and capability of the system to manage variations in demand and supply, at the lowest sustainable cost.

Where technically possible, energy and essential system services will be co-optimised in the new market

3.2 Secondary Market Parameters

3.2.1 Competition in the provision of at least some essential system services

The increasing competitiveness of new technologies, such as energy storage solutions, in providing a range of services necessitates changes to enable consumers and the broader market to benefit from these technologies. Aside from load following, the current WEM design provides limited opportunities for alternative providers to compete with Synergy to provide essential system services. Currently, spinning reserve and load rejection reserve[8] are procured from either Synergy as the default provider or through a contract between AEMO and another participant. Payment to Synergy for these services is determined through an administered price calculation, while prices for contracts with other parties are required to be lower than the price paid to Synergy.[9] The contracting opportunities for other parties are limited, as they are usually required to provide the relevant service at all times, at a price lower than the administered price paid to Synergy.

Retaining Synergy as the sole (or dominant) provider of essential system services was a pragmatic option when it directly controlled around 90 per cent of generation capacity in the SWIS in the early stages of the WEM.[10] However, as more competitors have entered the market and new technologies have emerged, some of which have the capacity to provide essential system services, there are likely to be long-term economic benefits in introducing competition in the provision of these services.

Market participants have previously expressed interest in greater competition in essential system services, voting for the introduction of a competitive spinning reserve market as the fourth highest priority reform in the former Independent Market Operator's 2013-2016 Market Rules Evolution Plan.

8 Spinning reserve and load rejection reserve services are used to respond to any sudden contingencies to arrest deviations in system frequency. Spinning reserve is used to respond to the loss of a generator, whereas load rejection reserve is used to respond to the loss of a major load (or group of loads).

9 This requirement is contained with clauses 3.11.8, 3.11.8C and 3.11.9 of the WEM Rules.

10 Currently, Synergy directly controls around 40 per cent of generation in the SWIS.

The adequacy of the existing essential system service definitions to allow the system operator to maintain the security of supply with minimal manual intervention in the market has been a concern for some time, with the potential need for new services raised in both the 2009 and 2014 Review of Ancillary Services Standards and Requirement Studies.[11] In the absence of these new service definitions, AEMO has advised that, with the increased penetration of intermittent generation (including DER), manual intervention will be more frequently required in the operation of the market to maintain system security. This intervention involves a judgement by AEMO on the appropriate dispatch that may not be based on the full suite of cost data.

With the increasing penetration of renewables, the existing generation fleet may be dispatched in an inefficient manner. This mismatch between changing requirements and existing dispatch will likely result in higher costs and may have contributed to the cost increases for load following services over the past five years.[12] These cost increases are passed directly to the consumers of electricity. New technologies have the potential to provide these services at a lower cost. The acquisition of essential system services within a competitive framework (whether that is a new spot market or an enhanced tendering process) must support this transition in a manner that minimises costs to consumers.

Work is currently underway by the Taskforce to develop a revised suite of essential system service definitions and acquisition methods to meet the security requirements of the WEM into the future. It is expected that some of these services, such as the current LFAS, will be procured through a real-time market that is co-optimised with the energy market. Market participants will simply need to provide their energy and essential system service offers in accordance with applicable rules and the market clearing engine will undertake the complex decision-making around energy and essential system services trade-offs, to minimise the overall cost of energy and essential system services. Market participants would be indifferent to whether their plant was dispatched for energy or an essential system service.

Increased competition should be facilitated in the provision of at least some essential system services

3.2.2 Reduce gate closure to between 0-15 minutes

The efficiency of markets is maximised when decision-making is informed by the most accurate and timely information that can be made widely available. In the context of electricity markets, reduced gate closure allows market participants to make decisions closer to real time with the benefit of more accurate forecasts (including forecasts of demand and wind) and up-to-date knowledge of network conditions and the status of generation facilities (including outages).

Reduced gate closure is expected to result in the following benefits.

[11] Available on the ERA website: www.erawa.com.au/electricity/wholesale-electricity-market/methodology-reviews

[12] In 2018-19, LFAS costs were $87 million, approximately 93 per cent higher than LFAS costs in 2014-15, $45 million.

- Improved efficiency due to the improved accuracy and certainty of forecasts at the time of gate closure, which have the practical effect of:
  - reducing risks for generators, which has the potential to reduce any risk premium within offer prices and increase market participation;[13] and
  - providing flexibility to market participants to respond to system changes closer to real time, maximising efficiency of the fleet.
- Allowing generators on outage to return to service sooner due to their ability to notify completion of the outage immediately, allowing the most efficient energy production to occur sooner.

Under current market arrangements, Synergy has an earlier gate closure than independent power producers,[14] to give AEMO certainty over what is available, and other participants an opportunity to submit their offers in relation to the Synergy portfolio offers. Previous consultation on this item indicates a desire by the sector to progress towards no gate closure over a period of time. If adopted, a progressive reduction from 15 minutes towards zero gate closure would take place after the planned commencement of the new market arrangements on 1 October 2022.

Given that energy and essential system services are to be co-optimised, a common gate closure would apply to the energy and essential system service markets. Also, noting the requirement for Synergy to bid and dispatch on an individual facility basis in the new market, and with appropriate controls for market power in place, a differential gate closure for Synergy is no longer needed. Gate closure will therefore be harmonised for all market participants.[15]

Gate closure in the new market will be reduced to 15 minutes at the start of the new market, and can be progressively reduced to zero over time.

3.2.3 Ex-ante pricing for both energy and essential system services

Prices are currently determined ex-post in the WEM, a minimum of two days after the relevant trading interval. In contrast, the majority of liberalised electricity markets (for example, the National Electricity Market (NEM), PJM, ERCOT, and Singapore Electricity Market) determine prices on an ex-ante basis.[16]

[13] For example, improved certainty of forecasts enables a generator to more reliably predict when, and for how long, it may be able to generate. This helps it to more reliably identify opportunities to operate profitably, while at the same time potentially lowering the energy price.

[14] For facilities other than the Synergy portfolio, energy gate closure is 2 hours, and LFAS gate closure is between 5 and 10.5 hours. For the Synergy balancing portfolio, energy gate closure is between 4 and 9.5 hours, and LFAS gate closure is between 8 and 15.5 hours.

[15] This is also consistent with the current WEM Rules, whereby Synergy would have the same gate closure and offer submission timings as independent generators for any Stand Alone Facilities that are removed from the Synergy portfolio.

[16] The New Zealand electricity market and the Philippines WESM are both in the process of moving from ex-post to ex-ante pricing.

The decision between ex-ante and ex-post pricing represents a trade-off between greater certainty (ex-ante) and greater accuracy (ex-post). Improved price certainty directly influences the confidence with which generators can make commercial and operational decisions. A shift to ex-ante price determination would also remove the need for constraint payments to provide 'make-whole' payments to generators where ex-post prices are different from what was forecast at the time of dispatch.[17] This benefit is expected to outweigh the benefit from the marginal improvements in accuracy that are delivered by ex-post pricing.

Stakeholders have been broadly supportive of this proposal. Ex-ante pricing should be adopted for both energy and essential system service markets.

Ex-ante pricing will be adopted for both energy and essential system service markets

3.2.4 Five-minute dispatch interval

A shorter dispatch interval (i.e., increasing the frequency with which dispatch instructions are issued to generators) will allow better decision making by participants through provision of timely and accurate information closer to real time. This will allow participants to adjust dispatch positions more swiftly to reflect physical facility limitations (e.g. minimum loading).

If dispatch instructions are issued more frequently, the ability of the energy market to match supply to fluctuating demand is improved, shifting the boundary between the Balancing Market and LFAS. This has the potential to reduce reliance on potentially more expensive LFAS.

In the Balancing Market, generators are dispatched to targets at the end of the dispatch interval based on forecasts available at the time that the instructions are formulated (typically 10-15 minutes ahead of when dispatch is required to commence). A shorter dispatch cycle reduces the forecast horizon and would be expected to yield improvements in forecast accuracy, all other factors aside. This reduces the reliance on LFAS to compensate for forecasting error.

A shorter dispatch cycle would also dramatically lessen the requirement for LFAS to balance the fast ramping of generators, which in many cases exceeds the rate that is necessary for balancing supply and demand and sees a generator reach its dispatch target before the end of the interval.

A five-minute dispatch interval is common practice in electricity markets, and many new market clearing dispatch engines incorporate this as a standard feature. Five-minute dispatch interval will therefore be adopted in the WEM.

With the adoption of a five-minute dispatch interval, a closer look at the current 30-minute settlement process is warranted. A five-minute dispatch interval will enable the calculation of spot prices for each five-minute interval. If the current process of settling the market on a 30-minute basis is retained, a single price for the trading interval would need to be calculated.

[17] It is noted that constrained-on or 'make whole' payments will be retained to compensate generators when they are required to run even though their offer prices are higher than the reference node price. This is discussed in section 3.2.9.

The single spot price for the interval could be the time-weighted average of the six, five-minute dispatch prices over the 30-minute trading interval.

However, the averaging process creates spot prices that can be much lower than one or more of the corresponding dispatch prices. This can create a problem for peaking generators that are dispatched for part of a trading interval, who risk being settled on the basis of a spot price that is lower than the generator's offer price and does not allow the generator to recover its short-run costs.

Noting the potential problems of a mis-match between dispatch and settlement periods and the rules recently approved by the Australian Energy Market Commission to implement five-minute settlement in the NEM commencing 1 July 2021, the Taskforce considers that the potential for shorter settlement timeframes be further explored. A position on settlement periods, the basis for settlement (i.e. global settlement, settlement by difference, or the status quo), and settlement timelines will be outlined in a later paper on the topic of Settlement, following further consultation with the sector and AEMO.

A five-minute dispatch interval will be adopted in the WEM and further consideration will be given to five-minute settlement.

3.2.5 Basis for dispatch

The energy output of a generator can be measured in two ways.

1. Supply 'as-generated' is measured at the generator terminals and represents the entire output from the generator.
2. Supply 'sent-out' is measured at the generator's connection point, and represents only the electricity supplied to the market, excluding the generator's auxiliary loads (and any other loads behind the connection point).

The current Balancing Market is designed around the concept of sent-out dispatch. For example:

- generators specify sent-out quantities in their balancing submissions;
- the Balancing Merit Order uses sent-out quantities; and
- the dispatch instructions sent to independent power producer facilities specify sent-out dispatch targets.

Independent power producers are responsible for managing their generators and auxiliary loads to ensure that they achieve the sent-out target levels in their dispatch instructions. However, AEMO dispatches most facilities in the Synergy portfolio on an as-generated basis.[18]

[18] For example, the set points sent to Synergy facilities operating under Automatic Generation Control are as-generated values. This use of as-generated dispatch does not contravene the WEM Rules, which are silent on how AEMO should control the individual facilities within the Synergy portfolio.

The Reserve Capacity Mechanism is based on sent-out quantities, with generators being certified on the basis of their sent-out capacity. The obligations on generators holding Capacity Credits in relation to STEM and balancing submissions, outages and performance testing are all expressed in terms of sent-out quantities.

Changing the Reserve Capacity Mechanism to be based on as-generated quantities is not a viable option because as-generated capacity does not provide an accurate estimate of the value provided to customers by a generator. For example, a generator with a 100 megawatt (MW) nameplate capacity and a 20 MW auxiliary load (at maximum output) provides less capacity value to the market than a generator with the same nameplate capacity but a 5 MW auxiliary load at maximum output, as the additional 15 MW of auxiliary load does not contribute to meeting peak customer demand. For this reason, it is intended that the Reserve Capacity Mechanism remains based on sent-out quantities.

Retention of sent-out dispatch is preferred by the Taskforce for the following reasons.

- Most stakeholders have previously expressed a strong preference to continue using sent-out dispatch to not complicate existing mechanisms based on it.
- Sent-out dispatch places responsibility for managing the volatility of auxiliary loads on the generator rather than the market.
- As-generated dispatch would require changes to several Reserve Capacity Mechanism processes, including certification, testing, outage management, performance assessment and the calculation of capacity refunds – this would create additional implementation overheads and further increase the complexity of the Reserve Capacity Mechanism.
- As-generated dispatch would, to support the Reserve Capacity Mechanism, require the development of methods to estimate the auxiliary load of a generator producing a particular as-generated quantity, which may not be feasible for some generating systems with relatively unpredictable auxiliary loads or other behind-the-fence loads.
- As-generated dispatch would require independent power producers, who may have already incurred material costs to comply with sent-out dispatch instructions, to make further changes to support compliance with as-generated dispatch instructions.

However, a rule-based requirement to dispatch all facilities on a sent-out basis will result in costs and implementation challenges for Synergy. AEMO suggests that a combination of as-generated and sent-out dispatch arrangements can be retained in the new market without posing risks to system operations. All other things unchanged, a universally applied basis for dispatch for all market participants should only be pursued if there is a demonstrable benefit in doing so. It is therefore considered that a pragmatic approach to the basis for dispatch be maintained which allows generators to continue existing mechanisms for dispatch.

A combination of dispatch on a ‘sent-out’ and ‘as-generated’ basis will remain a feature of the market.

3.2.6 Self-commitment for generators

Self-commitment of generating units is the current practice in the WEM whereby generators manage the risks of scheduling plant for start-up and shut down, with each generator’s preferences being provided to AEMO via its offer price, quantity and operating constraints. Many liberalised, competitive electricity markets operate on a self-commitment model. Central commitment can be necessary where most of the generation fleet has long start up times, high start-up costs, or inflexible operating constraints, and where power system constraints are significant or volatile, but this is not currently the case in the WEM. Other design proposals, when implemented, will increase transparency in the WEM so that generators are more able to forecast market conditions and make efficient decisions about scheduling their plant.

As load changes on the system become more volatile, AEMO may need to directly commit some types of generation. This requirement can potentially be achieved through specific essential system services contracts. However, improved forecasting, shorter dispatch intervals, reduced gate closure, and co-optimisation working together would reduce the need for such interventions. It is likely that AEMO will require a forward view of participant's intention to commit/de-commit facilities (and behind the fence generating units), to facilitate power system security assessments and highlight any potential need for intervention.

Self-commitment for generators will therefore be retained in the new market.

Self-commitment for generators will be retained in the new market.

3.2.7 Single market price with a single reference node at a load centre with potential for more granular dispatch

Single market price

Consideration has been given to increased locational granularity in pricing. Locational pricing is a way for wholesale energy prices to reflect the value of energy at different locations, accounting for the patterns of load, generation and the physical limits of the transmission system. Locational granularity of prices affects how accurately the price paid to market participants reflects the economic value of energy at a particular location in the network. Locational granularity is important due to the effect of network congestion (or constraints) and losses and can drive efficient decision making by participants in relation to plant operation or level of load and longer-term investment decisions about generation, network investment and demand side response.[19]

Stakeholder consultation on this design element indicates market participants are generally opposed to the increased complexity (and increased costs to operate and manage the market) that locational pricing would entail. In particular, prices at two locations can diverge when network congestion occurs, causing basis risk for parties that trade between these locations. This basis risk requires the development of risk management mechanisms (such as financial transmission rights) in order to support such trading. Currently the STEM, which is designed around a single reference node price, offers the ability to hedge the risk of variable market

[19] It is noted that in the NEM, the Australian Energy Market Commission has recently commenced a review that proposes changes to improve granularity of locational pricing so that signals for generation and transmission network investment can be improved. https://www.aemc.gov.au/news-centre/media-releases/major-reforms-put-generation-and-transmission-same-page

prices. However, if locational pricing was to be adopted at this time, sizeable changes to the STEM combined with costs of adjustment for market participants would be incurred. Market participants considered that other design proposals, such as the introduction of a security-constrained market design and co-optimisation of energy and essential system services were significant changes in their own right and further complexity should be avoided at this time if possible.

Based on this, it is considered that the market will continue to be settled on a single price. However, importantly, a single market price does not preclude a more granular dispatch or market clearing model. In the absence of locational pricing, increased granularity in dispatch is important because it can provide accurate and tractable network congestion costs for identified locations on the network by examining the locational price differences across the network. This 'congestion rental' information can potentially be published to provide information to the wider industry. Market participants and other entities, such as the network operator, would be able to use this information to make decisions about generation and transmission investment, if the regulatory investment framework is also modified to more clearly support this. Over time, this could facilitate future evolution of the market, such as potentially moving to fully nodal pricing.

A single market price will be retained for the WEM.

Reference node at load centre

The current reference node for the WEM is the Muja 330kV busbar. This appears to have been selected as it is located at the largest source of generation in the SWIS and the interconnection of three transmission voltages at Muja terminal (330kV, 220kV and 132 kV). Electricity demand in the Muja region is very small when compared to the greater Perth metropolitan area.

The use of a generation centre as the reference node is atypical and is inconsistent with standard practice in the NEM (the other market with a single reference node for each state-wide zone), in which the reference node for each region is typically located at or near a major load centre (generally within the metropolitan area of the capital city).

There are theoretical, practical and equity-based reasons to consider a change in reference node for the SWIS.

1. A marginally-priced energy market sets the marginal price as the cost of an incremental unit (typically an additional 1 MW) of demand at the reference node. From a theoretical perspective, it makes sense that the reference node is located where an incremental unit of demand is more likely to be observed.
2. Given that electricity typically flows towards the major load centre, generators closer to that load centre are more likely to be required to generate if the network is congested, while energy supplied by more distant generators is constrained. Setting the reference node at that load centre sees their costs reflected in the energy price and may reduce the magnitude of constrained-on compensation.

3. As constraint equations are oriented to the reference node, the location of the reference node at a generation centre could provide an unwarranted advantage to generators that are connected at the reference node. These generators are unconstrained in terms of their ability to deliver energy to the reference node, at which the market is cleared, so are not readily constrained in the market clearing engine – even if the network prevents their energy being transmitted to customers. This could result in inequitable treatment of generators and practical challenges for the system operator to constrain these generators, which may require tailored workarounds.

For these reasons, shifting the reference node for the SWIS to a network location in the Perth metropolitan area, such as Southern Terminal, is economically desirable. Peak demand at Southern Terminal is more than double the peak demand at Muja.[20] Additionally, moving the reference node to Southern Terminal will result in a more accurate representation of the physical characteristics of the network and losses incurred.

Loss factors vary depending on the reference node. A change in the reference node does not change the relativity of marginal loss factors between two locations on the network – loss factors scale up or down according to the change in marginal loss factor between the old and new reference nodes.

Analysis conducted by ETIU, AEMO and Western Power shows that loss factors decrease by about 2.8 per cent in 2018-19 and 2.3 per cent in 2019-20 when they are recalculated using the existing methodology and Southern Terminal as the reference node.

A change in loss factors is not expected to have a material effect on market settlement. If loss factors are an exact reflection of losses on the network (and Synergy bids by facility, each with its own loss factor),[21] there is not expected to be a material change in aggregate revenue, only a redistribution between market participants. This analysis assumes that market participants will not change their bids materially in response to a change in loss factor.

Detail on the selection of Southern Terminal as the new reference node and the resultant effect on transmission marginal loss factors (for the current year) is provided in Appendix 1.

Consideration also needs to be given to whether the responsibility for calculating loss factors should be changed from Western Power to AEMO, and whether the calculation of loss factors should be more frequent (it is currently annual) and based on forecast information, including constraints and new planting schedule as opposed to the current historical usage information. This work is planned for early 2020, for potential implementation from a date after new market commencement in October 2022.

The reference node for the WEM will be moved to Southern Terminal, commencing 1 October 2022.

[20] As advised by Western Power, 8 July 2019.

[21] Synergy's facility level loss factors are anticipated to be calculated the same way as they would for independent power producers. This may require a calculation of Synergy's auxiliary load at generation sites.

3.2.8 The STEM will be retained

The STEM is a day-ahead market operated by AEMO, in which market participants can buy and sell energy for the following trading day to adjust their net bilateral positions. Market participants must offer all their available generation capacity into the STEM or pay refunds on their reserve capacity payments.

To date, the STEM has provided energy at reasonable prices,[22] good levels of certainty with low transaction costs, and incorporates market power mitigation measures relevant to the SWIS. Indeed, some smaller retailers purchase much of their energy from the STEM, allowing them to hedge their positions in the real-time market.

Previous analysis could not determine that the benefits of designing an alternative forward market that includes all of the features of the current market would outweigh the costs.

It is possible that the WEM may become increasingly competitive as the result of structural changes to the market following implementation of the Energy Transformation Strategy initiatives. Alternatively, increasing levels of intermittent generation in the future may mean that different forward market mechanisms are required to incentivise intermittent generators to meet their day-ahead positions thereby contributing to system security. If this is the case, different forward market designs may develop, as required, and supersede the STEM. In addition, market evolution to increasing locational granularity and pricing would increase the complexity associated with retaining the STEM, which may reduce its usefulness in the future.

Notwithstanding the future evolution of the market, which may necessitate changes, the Taskforce considers that the STEM currently provides a useful service, particularly to smaller retailers. Moreover, the materiality of other changes to the spot market make it less attractive to make substantial changes to the STEM in the short term. The STEM could be reviewed post-2022, if there is decreased evidence of its utility. It is therefore considered that the STEM be retained with its current primary purpose of providing hedging opportunities to market participants, while further work is done on exploring improvements needed for it to function properly within the new WEM and network access framework.

The STEM continues to provide a useful service, particularly to smaller retailers, and will be retained in the new WEM design.

3.2.9 Constrained payments

Constrained-on payments

Network limitations can result in situations where a generator is scheduled to operate despite its offer price being higher than the reference node price. In a market with a single reference node price (such as the WEM), this higher price does not set the market clearing price. For example, flow on a transmission line to a remote part of the network may reach its thermal limit, requiring energy to be generated locally to serve any additional demand above that limit.

[22] Since the commencement of the new Balancing and Load Following Markets in 2012, the STEM clearing price has remained in the range of $40-$60 per MWh.

In this situation, the generator is considered to be constrained on. A 'constrained-on' compensation mechanism is required to be retained in the WEM because of the obligations on generators holding capacity credits to make available all their available capacity in the STEM and Balancing Market, or risk paying reserve capacity refunds. Further, if such generators were not eligible for these make-whole payments, they may have an incentive to offer into the market in a way that does not reflect their underlying costs, which can lead to inefficient dispatch and overall higher costs to consumers.

A generator that is constrained on is paid constrained-on compensation, consistent with the principle that a generator that is required to operate, when it otherwise wouldn't have, should be compensated for these costs.[23] Constrained-on compensation is funded by loads on the basis of their share of total consumption.

The current mechanism was designed on the basis that it would be required infrequently. As a result, if a facility has been constrained on for multiple consecutive trading intervals, its upwards out of merit dispatch quantity may be under-estimated and its compensation inadequate.

Whilst further work is needed on the appropriate design for constrained-on payments and associated measures to prevent any abuse, the Taskforce considers that it needs to be retained to properly compensate generators that are required to operate despite their offer price being higher than the reference node price. Previous stakeholder feedback was broadly supportive of retention.

Constrained-on payments will be retained in the new market.

Constrained-off payments

Under the proposed security-constrained market design, network constraints can lead to situations where a generator is not scheduled to operate, despite its offer price being lower than the price at the reference node. For example, flow on a transmission line from a remote area of the network may reach its thermal limit, restricting the energy that can be generated by one or more generators in that area. In these situations, a generator would be considered to be 'constrained off' under the current market design.

The Taskforce considers that, as a matter of principle, a generator that is constrained off by the security-constrained dispatch process should not be entitled to compensation from the market. This is because the right of a generator to the transfer capability of the network is equally determined by both economic and system security factors and not economic factors alone.[24]

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[23] A generator may be constrained on in response to a network constraint or as the result of forecasting error (where the final Balancing Price is different to the price suggested by the dispatch forecast) or dispatch error.

[24] The Energy Transformation Taskforce is separately considering the potential for compensation for incumbent generators with firm access rights.

For this reason, constrained-off compensation will not be included in the new market design.

Constrained-off payments will be removed as part of the design of the new market.

3.2.10 Synergy offering in essential system service markets

The WEM Rules contain provisions to prevent the abuse of market power in the LFAS market[25]. Synergy, due to its dominant position in the market, is required to act as the default provider of the service.

Synergy will continue to control a large proportion of the market's generation through to 2022, and likely beyond. The generation controlled by Synergy also represents a significant proportion of the generation that currently supports, and will likely continue to be required to maintain, the secure operation of the power system post 2022. This position may change over time as new investment in capable technologies is introduced. Until this occurs, the secure operation of the SWIS will likely require the participation of the generation units controlled by Synergy in any real-time essential system service markets. Regular review of the requirements, as currently provided for in the WEM rules, will continue to be undertaken with a view to supporting competitive provision in the medium to long term.

Synergy will be required to offer into essential system service markets under the new WEM design.

3.2.11 Controls for efficient pricing outcomes

The market improvements outlined in this paper will greatly increase transparency around the operation of the market. This will help to prevent or expose any abuses of market power and is expected to increase stakeholder confidence in the market and encourage greater levels of participation and competition. However, specific market power controls in the new market will need to be updated to align with the planned improvements. These are related to the definition of short run marginal cost in the context of co-optimisation, re-offering rules in the context of reduced or removed gate closure, and the need for essential system service price limits in the context of potential introduction of new essential system service markets. In addition, reviewing how exercise of market power is defined in terms of its effect on market prices, will greatly assist both market participants and the regulator to understand and monitor it.

Market power controls will be reviewed in light of the changes planned for the new market.

[25] Clause 7B.2.15 requires that LFAS submission prices must reflect a market participant's reasonable expectation of the incremental change in the LFAS facility's short run marginal cost when such behaviour relates to market power.

Appendix 1

Selection of a new reference node

The following criteria were developed to assist selection of a new reference node. These criteria are (in order of priority):

The reference node should be:

- located electrically near the region's major load centre, and should be downstream of any areas of congestion that are expected to occur between the major generation centre(s) and that load centre;
- in an electrically strong connection location (e.g. a busbar). Loss of supply to that location would be expected to occur only in conditions of very widespread disruption, such as system black; and
- not be located in close vicinity of a large scheduled generator which it may be necessary to constrain to achieve a secure network.

The busbar (a point at which electrical current passes in a major network node) should:

- be an individual discrete busbar that cannot be physically split (though it may be tied to others);
- not be in a terminal station where it is common for buses of that voltage to be split into complex topologies; and
- be a transmission (i.e. high-voltage) asset.

Western Power identified several potential reference nodes[26], being:

- Northern Terminal 330kV busbar or 132kV busbar;
- Southern Terminal 330kV or 132kV busbar;
- Cannington 132kV busbar;
- Western Terminal 132kV busbar; and
- East Perth 132kV busbar.

The Kwinana 330kV and 132kV busbars and the Neerabup 330kV and 132kV busbars were not considered potential reference nodes as they are major generation sources with minimum load, as is the current reference node at Muja.

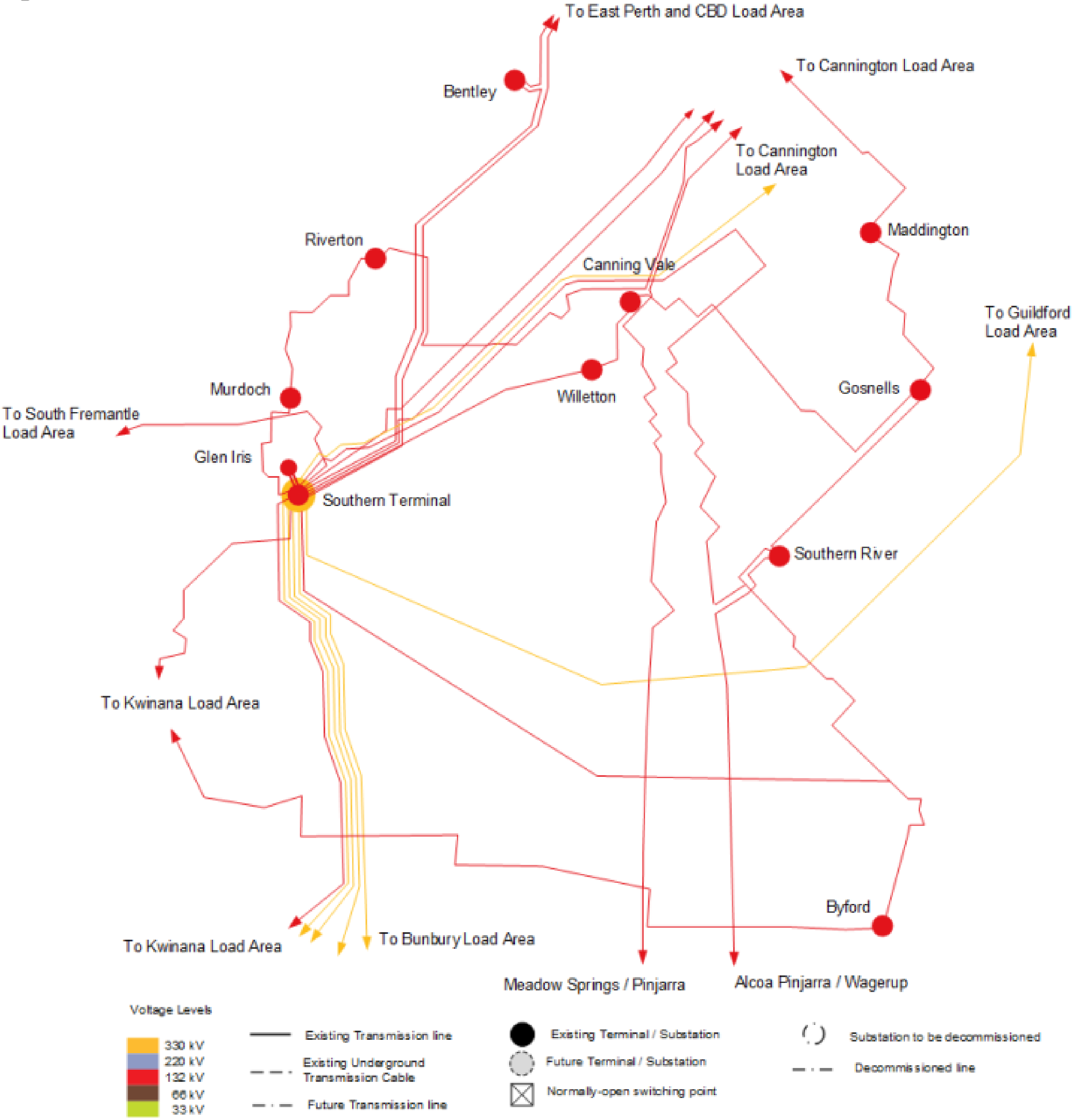
[26] Western Power, *Selection of Regional Reference Node for the South West Interconnected System*, provided to the Public Utilities Office on 27 September 2016.

The Southern Terminal 330kV busbar was considered most suitable because it:

- supplies the Southern Terminal load area, which is currently the largest load centre in the SWIS in terms of both maximum demand and total energy supplied;
- is downstream of projected network congestion with no generation connected to the 330kV busbar;
- terminates multiple 330kV circuits and is unlikely to be without supply unless in very widespread system outages; and
- is unlikely to be split into complex arrangements that require loss factors to be recalculated.

The Southern Terminal load area is shown in **Figure 1** (see next page).

Figure 1: Southern Terminal load area



Source: Western Power Annual Planning Report 2017

Effect of moving the reference node

Using 2018-19 loss factors, ETIU and AEMO estimate that changing the reference node to Southern Terminal would result in 0.02 per cent change in revenue on average for all market generators.[27]

Potential changes to market participant bids have not been modelled. Given the relatively minor changes in loss factors, it is expected that material changes in bids are not likely. It is also challenging to model these potential changes as they depend on commercial decisions of individual market participants.

The analysis shows some redistribution of revenue between market participants, which is due to their location in relation to the reference node and areas of high generation and load. Using 2018-19 loss factors, the largest variation for a single market participant was 5 per cent (which amounted to less than $1,400 for the year). This variation is an outlier, with the remaining market participants having revenue variations between -0.15 per cent and +0.17 per cent.

This analysis indicates moving the reference node from Muja to Southern Terminal does not lead to a material change in market outcomes on aggregate or for individual market participants.

Large-scale generation certificates

Market participants are eligible to receive large-scale generation certificates (LGCs) for electricity that generate from renewable energy sources. LGCs can be used to meet liabilities under the Australian Government's Renewable Energy Target, or traded with other entities that have such obligations.[28]

The volume of LGCs allocated to each market participant is calculated based on their loss factor- adjusted generation. A decrease in the loss factor for a market participant (for example, due to a change in reference node) may lead to a lower LGC allocation for a given quantity of generation.

It is acknowledged that moving the reference node will decrease the volume of LGCs some market participants are eligible for. However, moving the reference node is still justified given the following.

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[27] This analysis uses Western Power's recalculation of the loss factors for 2018-19 to be based on Southern Terminal. It uses the new loss factor to adjust the metered scheduled quantities and final Balancing Price to recalculate the settlement outcome. This is an estimate only, and does not consider any changes to market participant's bids (which are presumed to be immaterial given the relatively small change in loss factors). It also does not consider a change to Synergy's bidding behaviour.

[28] Clean Energy Regulator, *Large-scale generation certificates*, available at: http://www.cleanenergyregulator.gov.au/RET/Scheme-participants-and-industry/Power-stations/Large-scale-generation-certificates

- Any decrease in loss factors will be an adjustment to more accurately reflect the physical constraints on the network. Any subsequent loss in revenue reflects a more accurate loss factor adjustment.
- The change in loss factors is expected to be relatively small. As outlined above, the analysis indicates that for 2018-19 and 2019-20 the change in loss factors due to moving the reference node to Southern Terminal would be on average less than three per cent.
- The LGC revenue a market participant receives is more sensitive to changes in the value of LGCs. LGCs traded for between $80 and $90 from January 2018 to June 2018. The price has since declined to less than $40 in early 2019. The spot price of future contracts has also fell to around $15 in early 2019, indicating the market expects the spot price of LGCs to continue to decline.[29]

[29] Clean Energy Regulator, *Large-scale generation certificate market update – February 2019*

Provisional loss factors for Southern Terminal

The following table provides the provisional loss factors for 2018-19 and 2019-20 calculated using Southern Terminal as the reference node. This table is provided for illustration purposes. It is noted that the loss factors with Southern Terminal as a reference node would commence in the new market in October 2022, following relevant rules being made.

TLF code	Description	Muja		Southern Terminal	
		18/19	19/20	18/19	19/20
TAPA	Alcoa Pinjarra (Alcoa)	0.9736	0.9771	0.9474	0.9558
TAPL	Alcoa Pinjarra (Alinta)	0.9747	0.9767	0.9482	0.9554
TBLB	Bluewaters	1.0004	0.9992	0.971	0.9782
TBLS	Boulder (SCE)	1.1679	1.1689	1.1343	1.1442
TKRA	Karara Three Springs	1.0479	1.0431	1.0196	1.0202
TLWA	Lanwehr (Alinta)	1.0135	1.0113	0.9819	0.9862
TMBA	Mumbida Wind Farm	0.9573	0.9528	0.9318	0.9326
TMDP	Merredin Power Station (Nammarkin)	0.9997	0.9654	0.9222	0.938
TMGS	Greenough River Solar Farm (Mungarra)	1.0031	0.9946	0.9754	0.9743
TMSK	Mason Road (KPP)	1.0343	1.0307	1.0065	1.0077
TOLA	Oakley (Alinta)	1.0164	1.0144	0.9885	0.9926
TSAV	Transmission SWIN Average	1.0346	1.0339	1.0051	1.0122
TUAV	Transmission Urban Average	1.0429	1.0409	1.0137	1.0163
TWKG	West Kalgoorlie GTs	1.1172	1.097	1.0845	1.0728
TWOJ	Worsley (Joint Venture)	0.9721	0.998	0.9446	0.9772
TWOW	Worsley (Worsley)	0.9725	0.9984	0.945	0.9774
WAFM	Australian Fused Materials	1.0355	1.0319	1.0082	1.0095
WAKW	Kwinana Alcoa	1.035	1.0316	1.0075	1.0087
WALB	Albany	1.0535	1.0589	1.0227	1.0359
WAMT	Amherst	1.0461	1.0436	1.0169	1.0189
WAPM	Australian Paper Mills	1.0496	1.0467	1.0206	1.0223
WARK	Arkana	1.0441	1.042	1.0146	1.0177
WBCH	Beechboro	1.0447	1.0434	1.0149	1.0183
WBCT	Balcatta	1.0457	1.0444	1.0159	1.0198
WBDE	Baandee (WC)	1.0676	1.0691	1.0368	1.0472
WBDP	Binningup Desalination Plant	1.0173	1.0151	0.9888	0.9934
WBEC	Beckenham	1.0327	1.0276	1.0024	1.0036
WBEL	Belmont	1.0336	1.0308	1.0048	1.0064
WBGM	Boddington Gold Mine	1.0106	1.0092	0.9814	0.9888
WBWF	Badgingarra Wind Farm[30]		0.9917		0.9685
WBHK	Broken Hill Kwinana	1.0397	1.0356	1.0118	1.0127
WBIB	Bibra Lake	1.0431	1.0403	1.0138	1.0154

[30] This point did not exist in 2018/19

TLF code	Description	Muja		Southern Terminal	
		18/19	19/20	18/19	19/20
WBKF	Black Flag	1.1849	1.1867	1.1512	1.1627
WBLD	Boulder	1.1692	1.171	1.1359	1.1473
WBNP	Beenup	1.0277	1.0312	0.9976	1.0092
WBNY	Bounty	1.085	1.0921	1.0541	1.07
WBOD	Boddington	1.0097	1.0082	0.9797	0.9863
WBPM	British Petroleum	1.0423	1.0393	1.0147	1.0162
WBSI	Marriott Road Barrack Silicon Smelter	1.0152	1.0145	0.9866	0.9934
WBSN	Busselton	1.0509	1.0524	1.0206	1.0289
WBTN	Bridgetown	1.0116	1.0139	0.9824	0.9927
WBTY	Bentley	1.0373	1.0346	1.0089	1.0106
WBUH	Bunbury Harbour	1.008	1.0173	0.9787	0.9947
WBYF	Byford	1.036	1.0339	1.007	1.0087
WCAP	Capel	1.0289	1.0388	0.9993	1.016
WCAR	Carrabin	1.1144	1.1207	1.0824	1.098
WCBP	Mason Road CSBP	1.0351	1.0304	1.007	1.0081
WCCL	Cockburn Cement Ltd	1.0342	1.0307	1.0067	1.008
WCCT	Cockburn Cement	1.0351	1.0325	1.0068	1.0083
WCGW	Collgar Windfarm	1.006	1.0063	0.9765	0.9849
WCKN	Clarkson	1.0467	1.0493	1.0172	1.0248
WCKT	Cook Street	1.046	1.0433	1.0168	1.0188
WCLN	Clarence Street	1.0385	1.0361	1.0097	1.0113
WCLP	Coolup	1.0184	1.0591	0.9887	1.036
WCOE	Collie	1.0187	1.0204	0.9889	0.9984
WCOL	Collier	1.039	1.0367	1.01	1.0117
WCPN	Chapman	1.0151	1.0166	0.9863	0.9923
WCPS	Collie PWS	0.9974	0.9958	0.9681	0.9739
WCTE	Cottesloe	1.0474	1.045	1.018	1.0203
WCUN	Cunderdin	1.1041	1.0939	1.0725	1.0695
WCVE	Canning Vale	1.0311	1.0286	1.0029	1.0044
WDTN	Darlington	1.0452	1.0427	1.0155	1.0182
WDUR	Durlacher	1.0104	1.0106	0.9822	0.9878
WEDD	Edmund Street	1.0474	1.0443	1.0183	1.0198
WEDG	Edgewater	1.0495	1.0485	1.0188	1.0237
WEMD	Emu Downs	1.027	1.0205	0.999	0.9985
WENB	Eneabba	1.0384	1.0321	1.0093	1.0085
WFFD	Forrestfield	1.0442	1.0409	1.0148	1.0173
WFRT	Forrest Ave	1.0477	1.0448	1.0187	1.0206
WGGV	Golden Grove	1.0661	1.0616	1.0373	1.0387
WGNI	Glen Iris	1.0301	1.026	1	1.0012
WGNL	Gosnells	1.0317	1.0294	1.0029	1.0044
WGNN	Newgen Neerabup	1.0372	1.0336	1.0084	1.0066

TLF code	Description	Muja		Southern Terminal	
		18/19	19/20	18/19	19/20
WGTN	Geraldton	1.0104	1.0106	0.9822	0.9878
WHAY	Hay Street	1.0456	1.0425	1.0165	1.0185
WHBK	Henley Brook	1.0474	1.0456	1.0172	1.0197
WHFS	Hadfields	1.0459	1.0436	1.0161	1.0192
WHIS	Hismelt	1.034	1.0313	1.021	1.0089
WHZM	Hazelmere	1.0395	1.0368	1.0104	1.013
WJDP	Joondalup	1.0467	1.049	1.017	1.0245
WJTE	Joel Terrace	1.0457	1.0431	1.0162	1.0183
WKAT	Katanning	1.052	1.069	1.0213	1.0461
WKDA	Kalamunda	1.046	1.0435	1.0162	1.0188
WKDL	Kewdale	1.0327	1.0298	1.0043	1.0059
WKDN	Kondinin	1.0445	1.0457	1.0139	1.023
WKDP	Kwinana Desalination Plant	1.035	1.0334	1.0072	1.0094
WKEL	Kellerberrin	1.0794	1.0706	1.0474	1.0475
WKEM	Kemerton PWS	1.0108	1.0105	0.9795	0.9814
WKMC	Cataby Kerr McGee	1.0413	1.0357	1.0131	1.0133
WKMK	Kerr McGee Kwinana	1.032	1.0284	1.0045	1.0054
WKMM	Muchea Kerr McGee	1.0454	1.0432	1.0168	1.0203
WKND	Kwinana Donaldson Road (Western Energy)	1.0323	1.028	1.001	1.0017
WKOJ	Kojonup	1.0281	1.034	0.9979	1.0117
WKPS	Kwinana PWS	1.0301	1.0292	1.0026	1.0062
WLDE	Landsdale	1.0467	1.0455	1.0168	1.0204
WMAG	Manning Street	1.0472	1.0454	1.0175	1.0209
WMBR	Mt Barker	1.0597	1.0636	1.0287	1.0406
WMCR	Medical Centre	1.0521	1.0488	1.0224	1.0246
WMDN	Maddington	1.0313	1.0287	1.0027	1.0042
WMDY	Munday	1.0434	1.0402	1.0144	1.017
WMED	Medina	1.0385	1.0361	1.0096	1.0114
WMER	Merredin	1.0612	1.062	1.0298	1.0391
WMGA	Mungarra GTs	0.9957	1.0107	0.9695	0.9858
WMHA	Mandurah	1.0243	1.0242	0.9953	0.9996
WMIL	Milligan Street	1.0459	1.0428	1.0163	1.0188
WMJP	Manjimup	1.0183	1.0209	0.9884	0.9988
WMJX	Midland Junction	1.0402	1.0371	1.0107	1.0132
WMLG	Malaga	1.0419	1.0393	1.0126	1.0157
WMOR	Moora	1.055	1.0519	1.0255	1.0278
WMOY	Morley	1.0463	1.044	1.0164	1.0193
WMPS	Muja PWS	1	1	0.9704	0.9773
WMRR	Marriot Road	1.0131	1.0126	0.9843	0.991
WMRV	Margaret River	1.0996	1.1086	1.0677	1.084

TLF code	Description	Muja		Southern Terminal	
		18/19	19/20	18/19	19/20
WMSR	Mason Road	1.034	1.0306	1.0066	1.0079
WMSS	Meadow Springs	1.0241	1.023	0.9951	0.9987
WMUC	Muchea	1.047	1.0452	1.0174	1.0208
WMUL	Mullaloo	1.0476	1.0485	1.0179	1.0239
WMUR	Murdoch	1.0291	1.0263	1.0014	1.0016
WMYR	Myaree	1.0543	1.0513	1.0245	1.0261
WNBH	North Beach	1.0475	1.0469	1.0176	1.0219
WNED	Nedlands	1.0501	1.046	1.0209	1.0228
WNGK	NewGen Kwinana	1.0247	1.0226	0.9968	0.9993
WNGN	Narrogin	1.0272	1.0289	0.9971	1.0064
WNOR	Northam	1.0643	1.0621	1.0339	1.0373
WNOW	Nowgerup	1.0449	1.0454	1.0164	1.023
WNPH	North Perth	1.0462	1.0437	1.0168	1.019
WOCN	O'Connor	1.0526	1.0499	1.0231	1.0248
WOPK	Osborne Park	1.0462	1.045	1.0166	1.02
WPBY	Padbury	1.0485	1.0493	1.0187	1.0242
WPCY	Piccadilly	1.1691	1.1692	1.1348	1.1441
WPIC	Picton 66kv	1.0065	1.0171	0.9775	0.995
WPJR	Pinjar	1.0322	1.0369	#N/A	1.0139
WPKS	Parkeston	1.1686	1.1633	1.1348	1.1332
WPLD	Parklands	1.0222	1.02	0.9936	0.9969
WPNJ	Pinjarra	1.01	1.01	0.9823	0.9871
WRAN	Rangeway	1.0137	1.014	0.9851	0.9906
WRGN	Regans	1.0431	1.0381	1.0144	1.0152
WROH	Rockingham	1.0385	1.0357	1.0096	1.0113
WRTN	Riverton	1.0307	1.0283	1.0025	1.003
WRVE	Rivervale	1.0335	1.0306	1.0049	1.0064
WSFT	South Fremantle 66kV	1.0246	1.0419	1.0164	1.017
WSNR	Southern River	1.0305	1.029	1.0018	1.0035
WSPK	Shenton Park	1.0512	1.0473	1.021	1.0229
WSRD	Sutherland	1.0475	1.0432	1.0177	1.019
WSUM	Summer St	1.0465	1.0425	1.0167	1.0183
WSVY	Sawyers Valley	1.0499	1.0472	1.0205	1.0232
WTSG	Three Springs	1.0418	1.0366	1.0127	1.013
WTST	Three Springs Terminal	1.0499	1.0499	1.0127	1.0499
WTTS	Tate Street	1.0326	1.0298	1.004	1.0055
WUNI	University[31]	1.0747		1.0387	
WWAG	Wagin	1.0575	1.0749	1.0266	1.0519
WWAI	Waikiki	1.0387	1.0373	1.0095	1.0119

[31] This point was decommissioned in 2019/20

TLF code	Description	Muja		Southern Terminal	
		18/19	19/20	18/19	19/20
WWCL	Western Collieries	0.99	0.9977	0.9616	0.9768
WWDN	Wembley Downs	1.0514	1.0496	1.0218	1.0245
WWEL	Welshpool	1.0328	1.0301	1.0041	1.0055
WWGA	Wangara	1.0469	1.046	1.0173	1.0219
WWGP	Wagerup	0.9701	0.9849	0.9434	0.9638
WWKT	West Kalgoorlie	1.1654	1.1674	1.1318	1.1431
WWLN	Willetton	1.0317	1.0284	1.0024	1.0038
WWMG	Western Mining	1.0354	1.0326	1.0079	1.0093
WWNO	Wanneroo	1.0447	1.0497	1.0151	1.0248
WWNT	Wellington Street	1.0467	1.0437	1.0177	1.0197
WWSD	Westralian Sands	1.0234	1.0336	0.9939	1.0122
WWUN	Wundowie	1.0846	1.067	1.0537	1.0426
WWWF	Walkaway Windfarm	0.9475	0.9447	0.9219	0.9244
WYCP	Yanchep	1.0467	1.0496	1.0172	1.0246
WYER	Yerbillon	1.1138	1.1201	1.0817	1.0975
WYKE	Yokine	1.0461	1.0439	1.0165	1.0192
WYLN	Yilgarn	1.0948	1.0967	1.0636	1.0745