



Energy Transformation Taskforce

Energy Scheduling and Dispatch Information Paper

6 August 2019

Table of Contents

1. Purpose	4
1.1 The Energy Transformation Strategy	4
1.2 The purpose of this paper	4
1.3 Context for this paper	5
2. Introduction to energy scheduling and dispatch	6
2.1 The need for changes to energy scheduling and dispatch	6
2.1.1 Overview of current market structures in the WEM	7
2.1.2 Security constrained dispatch and network congestion	8
2.1.3 Co-optimisation of energy and essential system services	9
2.2 Head of power for rules around scheduling and dispatch	10
2.3 Structure of this document	10
3. Real-time energy market	11
3.1 Facility offers	11
3.1.1 Facility aggregation	11
3.1.2 Gate closure	16
3.1.3 Intermittent generation offers	23
3.1.4 Treatment of smaller facilities	25
3.1.5 Mandatory offer obligations	26
3.1.6 Fast start inflexibility profiles	30
3.2 Dispatch and scheduling	35
3.2.1 Network model for clearing	35
3.2.2 Ramping	41
3.2.3 Intermittent generator forecasting	44
3.2.4 Optimisation of energy storage utilisation in the real-time energy market	46
3.2.5 Market schedules	49
4. Short-term energy market	55
4.1 Interaction between STEM and real-time markets	55
4.2 STEM timing	59
5. Treatment of demand side resources	60
5.1 DSR participation in the real-time market	60
5.2 Treatment of behind-the-fence generation in a security constrained market	65
5.3 Aggregation of distributed demand side resources	66
Appendix A Market Schedule Timelines	69

1. Purpose

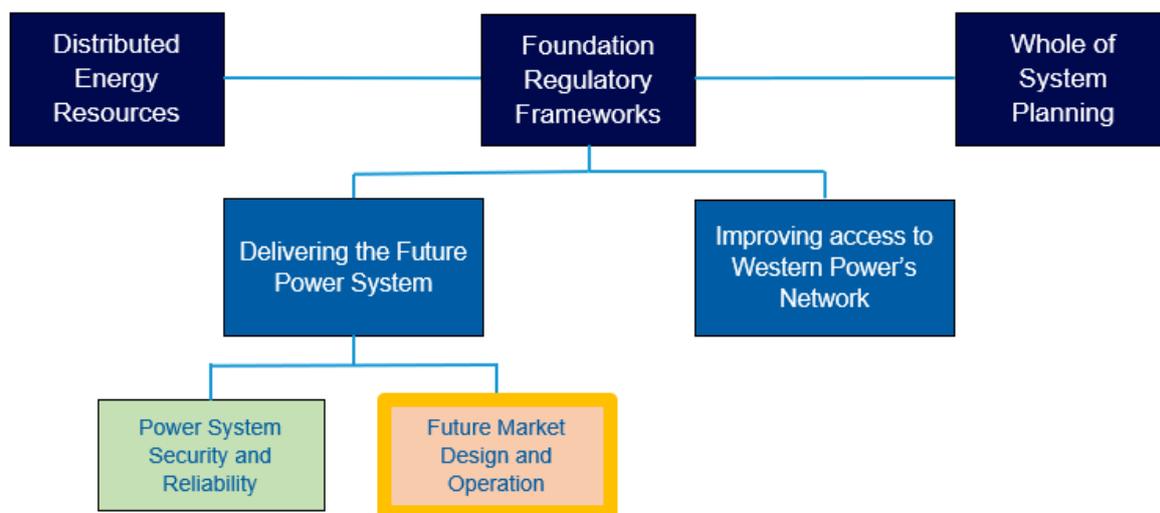
1.1 The Energy Transformation Strategy

This paper forms part of the work to deliver the 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), a dedicated unit within the Department of Treasury.

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/>.

This paper is prepared as part of the *Future Market Design and Operation* project (highlighted in **Figure 1**) within the Foundation Regulatory Frameworks work stream of the Energy Transformation Strategy.

Figure 1: Energy Transformation Strategy work streams



The Future Market Design and Operation project is undertaking improvements to the design and functioning of the WEM by:

- modernising WEM arrangements to implement a security-constrained economic dispatch (SCED) market design that optimises the benefits of the introduction of constrained network access for Western Power's network; and
- implementing a new framework for acquiring and providing essential system services.

1.2 The purpose of this paper

The purpose of this paper is to outline changes to market design relating to the scheduling and dispatch of energy under the new SCED model planned to be implemented in the

Wholesale Electricity Market (WEM) from 1 October 2022. This paper should be read in conjunction with the *Foundation Market Parameters*¹ information paper.

1.3 Context for this paper

This paper is one of a series covering design elements of the new SCED model. These changes are crucial to support the continuing security of the power system and the efficient operation of the WEM in an environment of rapidly changing technology and consumer demand.

These proposals build on the foundation market parameters, and address aspects of market design specifically relating to the scheduling and dispatch of energy.

Subsequent papers released by the Taskforce will cover the design of:

- essential system services acquisition;
- essential system services scheduling and dispatch;
- outage management;
- settlement;
- registration and participation;
- market information; and
- market evolution.

¹ Available on the Energy Transformation website <https://www.treasury.wa.gov.au/Energy-Transformation/Publications>.

2. Introduction to energy scheduling and dispatch

2.1 The need for changes to energy scheduling and dispatch

Current scheduling and dispatch mechanisms in the WEM were designed in the context of a predictable, unconstrained power system, with dispatch decisions rarely impacted by physical constraints under normal system operating conditions. When physical network constraints or power system security issues occur, their effects on dispatch are currently managed by manual intervention outside core market processes.

However, in recent times these assumptions have become less valid. Regardless of the model for network access selected, increases in network congestion, distributed generation (such as rooftop solar photovoltaic (PV) systems), intermittent generation (such as large-scale PV arrays and wind farms), and demand volatility will drive a reduction in the overall stability of the power system. The International Energy Agency recognised these changes in the 2018 World Energy Outlook, saying the following.²

'With higher variability in supplies, power systems will need to make flexibility the cornerstone of future electricity markets in order to keep the lights on. The issue is of growing urgency as countries around the world are quickly ramping up their share of solar PV and wind, and will require market reforms, grid investments, as well as improving demand-response technologies, such as smart meters and battery storage technologies.'

In the WEM, incidence of power system security issues requiring intervention in market dispatch is becoming more prevalent. In calendar year 2018, the Australian Energy Market Operator (AEMO) applied security constraints limiting the output of one or more non-Synergy facilities around 4.5 per cent of the time.³ Although the constraints impacted only around 17 GWh of energy (less than 0.1 per cent of total energy delivered through the system), incidence will increase over time. In 2018 and 2019, AEMO also called on backup load following service on five occasions (as compared to none in previous years) to manage power system security challenges arising from wind and solar PV variability, generator trips, or not enough load following service available.

In addition, network congestion is on the rise with new generators, largely renewable, connecting in fuel-abundant parts of the network. To manage network congestion issues in the 'unconstrained network' model, Western Power has sought to offer runback schemes or Generator Interim Access arrangements, the underlying principle of which is that they do not impinge upon the access rights of existing generators.

At present, most network congestion and system security issues are handled manually by control room staff via re-dispatch of the Synergy portfolio of generators. These actions are not visible in market data, and can result in inefficient dispatch of the portfolio, and perhaps overall inefficient dispatch, if there is a more optimal dispatch solution involving non-portfolio facilities.

² <https://www.iea.org/newsroom/news/2018/november/world-energy-outlook-2018-examines-future-patterns-of-global-energy-system-at-a-t.html>

³ Noting per above that this figure does not include the unmeasurable instances where the portfolio is re-dispatched to manage constraints or volatility

Re-dispatch of the portfolio is also not specifically observable to the market as an incidence of congestion or volatility management, resulting in a lack of transparency. As well as introducing inefficiencies, manual intervention creates the potential for inconsistency of process, and increases the risk of scenarios that could ultimately result in supply disruption. With increasing volatility, this situation is not sustainable.

This requires a more sophisticated approach to the operation of the WEM, including having network and security constraints included in core market processes and accounted for in real-time dispatch, rather than managed manually and after the fact.

In addition, rapidly advancing technology requires multiple other changes to the market design to allow new types of technology (including energy storage, distributed energy resources and demand side participation) to compete on a level playing field with traditional forms of energy supply.

2.1.1 Overview of current market structures in the WEM

The WEM comprises four revenue recovery mechanisms:

1. **The Reserve Capacity Mechanism (RCM):** The RCM accredits facilities to provide capacity into the energy and essential system services markets, to ensure sufficient capacity to meet demand at all times. The RCM requires market customers to fund the cost of meeting their share of a specified capacity target for the whole WEM by either bilaterally contracting to purchase capacity credits from certified facilities, or paying an administered price.
2. **Forward energy markets**, of which there are two.
 - a) The contract market: Market participants make bilateral agreements for sale and purchase of energy over a negotiated forward timeframe, at a negotiated price. This market is not centrally managed, but bilateral contract positions are registered with AEMO and netted-out as part of market settlement processes.
 - b) The Short-Term Energy Market (STEM): A day-ahead market, administered by AEMO, that allows participants to trade around their net bilateral contract position (as declared to the market).
3. **Real-time energy and ancillary service markets**, of which there are two.
 - a) The Balancing Market: A mandatory, gross pool into which all generators must offer their full 'available' capability⁴ with a two-hour gate closure (six-hour for Synergy). Every half-hour, the Balancing Market 'clears' energy to meet expected demand, without accounting for information about constraints on the network (as demonstrated in AEMO's network model), or current generation levels.
 - b) The Load Following Ancillary Service (LFAS) market: A market selecting facilities to provide LFAS on a half-hour basis. It runs four times each day, generating LFAS selections for a specified six-hour period with a three-hour gate closure. Participants must reflect their LFAS position in their Balancing Market offers.
4. **Administered ancillary service procurement mechanisms:** The remaining ancillary services are provided by Synergy by default, and costs are recovered through

⁴ Capacity that is not on an outage.

administrative arrangements, or procured by AEMO through direct contracts with market participants other than Synergy when the contract price offered is lower than the administered price for the ancillary service.

This paper outlines planned changes to the STEM and real-time energy markets. It also briefly covers general principles of essential system services⁵ co-optimisation. Changes to essential system service markets and procurement mechanisms will be covered in greater depth in later information papers to be published by the Taskforce following consultation with industry working groups.

2.1.2 Security constrained dispatch and network congestion

The South West Interconnected System (SWIS) has historically operated under an unconstrained network access regime. In constrained grid regimes, generators are not assured of congestion-free access to the network. New generators may connect even if there is insufficient transmission capacity.

While the owners of a facility under a constrained access arrangement face the risk of network congestion for periods of time, they do not face large-scale, deep network connection costs. Currently it is typical for transmission build lead times in the SWIS to be two to three times longer than generation build lead times, and there is a growing queue of parties interested in connecting to the SWIS. To allow these connections, Western Power offered bespoke solutions, such as runback schemes and the Generator Interim Access scheme, which attempt to optimise available network capacity using automated curtailment mechanisms.

The bespoke mechanisms developed to manage constrained connections are operated independently from wholesale market processes, creating issues around transparency, accuracy of market forecasts, and equity among market participants. Critically, they are becoming increasingly complex and difficult to manage, resulting in more distortion to market outcomes and impeding the delivery of the lowest sustainable cost of supply of electricity services to consumers. When access to the SWIS is supported by a SCED, the optimal economic dispatch can take network constraints into account without distortionary pre-market access schemes. This will allow more generators to enter the market earlier than if they had to wait for a transmission constraint to be lifted through augmentation of the transmission network.

A constrained network access regime recognises that it can be efficient to allow some network congestion⁶ to occur. That is, the savings from reduced or deferred network investment can far exceed the increased cost of generation during occasional periods of network congestion.

Nevertheless, network congestion does impose short-term costs on market participants and customers. Accordingly, an essential common feature of constrained grid regimes is a set of rules and algorithms to optimise the use of available network capacity in close to real time, and associated wholesale market systems to implement these rules. These rules and systems

⁵ Essential system services, referred to as Ancillary Services in the current WEM Rules, encompass all services required to maintain power system security and reliability. The new term better reflects their essential nature and applicability to the power system.

⁶ Network congestion occurs when one or more pieces of network equipment are operating at their limit, such that generation 'behind the constraint' cannot produce to its full capability.

enable available transmission capacity to be flexibly used by the optimal combination of generators (and other energy providers including energy storage and demand side response) at all times, no matter the state of the network.

A key outcome of the proposed introduction of SCED is to ensure that generation is dispatched to minimise the total cost of wholesale energy and essential system services, while explicitly accounting for the physical characteristics and security requirements of the SWIS. Finding the cheapest combination of generators involves optimising the injection (and where relevant, withdrawal) of energy at all locations across the network, considering network losses and constraints.

A successful constrained dispatch mechanism will also provide information to market participants, network operators, regulators and other stakeholders about the cost of congestion, enabling them to assess whether investment in transmission, generation or other technologies would be prudent to reduce congestion.

2.1.3 Co-optimisation of energy and essential system services

While this paper focuses on energy scheduling and dispatch, it must consider the need for co-optimisation of essential system services.

Co-optimisation refers to the process of determining the overall least-cost dispatch outcome for both energy and essential system services. As is the case in the current market, participants will continue to make offers for their facilities to supply energy and one or more essential system services. Each market represents the provision of a clearly defined set of services, each separate and distinct from the others, and participants can choose to offer into all, some, or none of the markets.⁷ The market clearing process then solves all the markets at the same time, to arrive at the lowest cost secure solution, accounting for complex trade-offs, including the following.

- Each megawatt (MW) of capacity can only be allocated to one service at a time.
- A facility's current production level will influence what essential system services it can provide.
- The energy dispatch (how much and from which facilities) can affect the total quantity of each essential system service required.

Co-optimisation can be used regardless of the essential system service settlement mechanism adopted. It can also be used whether essential system services are procured purely through real-time markets (with real-time prices used for settlement), where services are procured and remunerated on a longer-term basis, or where a hybrid model is used.

Co-optimisation simplifies and de-risks the bidding process for market participants, allowing generators to offer simultaneously into energy and multiple essential system services markets, while being commercially indifferent as to which services they are dispatched to provide.

⁷ Noting that dominant participants may be required to offer into some essential system service markets as a market power mitigation measure.

Later design papers will address essential system service procurement, scheduling and dispatch in greater detail.

2.2 Head of power for rules around scheduling and dispatch

All design changes outlined in this paper will be made via the WEM Rules, made under section 123 of the *Electricity Industry Act 2004* and Part 2 of the Electricity Industry (Wholesale Electricity Market) Regulations 2004.

2.3 Structure of this document

The remainder of this document is set out as follows.

- *Section 3* sets out the design of the real time SCED market that are fundamental to the reform.
- *Section 0* sets out changes to the STEM resulting from the introduction of SCED in real-time markets.
- *Section 5* sets out measures for scheduling and dispatch of new technologies, including energy storage and demand side participation.

For each area of energy scheduling and dispatch addressed, the paper describes the:

- current market arrangements and the principles behind the current design;
- factors and considerations informing market design, including changes to market conditions (both past and projected); and
- the market design modifications to be implemented by the Taskforce.

3. Real-time energy market

Many of the market settings addressed in the *Foundation Market Parameters* information paper relate to the operation of the real-time energy market. Under SCED (as discussed in section 2.1.2 above):

- all participants submit individual offers for each facility;
- energy and essential system services are co-optimised (cleared at the same time);
- the ex-ante market prices used for dispatch are also used in settlement;
- dispatch instructions are given for each five-minute interval;
- dispatch instructions reflect the amount of energy to be sent-out from the facility, after facility usage has been accounted for; and
- participants make their own commitment decisions for their facilities, structuring their offers to reflect whether they want their facility to be dispatched or not.

This section of the paper expands upon these topics and addresses three aspects of energy scheduling and dispatch, where the initial review of foundation market parameters noted the need for further analysis, specifically:

1. the timing of gate closure, albeit no more than 15 minutes in advance of real time;
2. the potential for clearing the market on a more granular basis than the single region to be used for settlement; and
3. an option for central commitment for flexible facilities with short start-up times.

This section also describes challenges and potential solutions for:

- the grouping of individual generation facilities into a single aggregated facility;
- intermittent generator offer structures;
- interaction between RCM outcomes and real-time market offers;
- ramping profiles; and
- market pre-dispatch schedules and the requirement to provide offers, or standing offers.

3.1 Facility offers

3.1.1 Facility aggregation

Offer granularity is the level of detail at which information about each facility is made visible to the market clearing engine. Dispatch granularity is the level of detail at which dispatch instructions are provided to participants for implementation in their facilities.

The temporal granularity of offers will change with the introduction of a five-minute dispatch interval. Generators will be able to submit a different set of offers for each five-minute interval, rather than the 30-minute interval used today. Consequently, the number of intervals in the day will increase from 48 to 288.

The granularity of offers for each generation facility is also important. The choice of granularity has the potential to affect the accuracy and efficiency of the automated dispatch calculations for both energy and essential system services. It also has implications for the operational flexibility retained by the facility owner.

Current approach

In the current WEM, each individual 'generation system' is classed as a facility in its own right. A stand-alone gas turbine can be a facility, as is a single wind turbine, and a collection of solar PV panels attached to a single inverter. This is the most granular level of information that could feasibly be used as an input for the market clearing process.

While AEMO needs information at this granular level, market participation on this basis would not necessarily affect the efficiency or security of the market or the power system, but it would impose additional operational and administrative burden on participants. For this reason, intermittent generation facilities injecting at the same network location must be represented in the market as a single aggregated facility.⁸ Other facilities can be collected together into an aggregated facility, at the discretion of AEMO. Examples of this in the current WEM include:

- combined cycle facilities, where one or more gas turbines are linked to a steam turbine are represented as a single aggregated facility;⁹ and
- multiple gas turbines injecting at the same network connection point, where it is operationally simpler for a facility owner to offer and be dispatched as a single facility.¹⁰

These aggregated facilities are represented in the market clearing process as a single entity, with capacity and facility characteristics representing all facilities within the aggregation.

Synergy facilities are further aggregated into a portfolio for market offer purposes, and then dispatched at facility level (including some aggregated facilities).

Regardless of facility aggregation, spinning reserve requirements are set based on the largest contingency – typically the individual facility with the highest generation, which could theoretically be part of an aggregated facility.¹¹ Spinning reserve activation is managed manually by AEMO's control room operators.

Future state

With the introduction of co-optimisation, essential system services will no longer be cleared ahead of energy, and dispatch of contingency reserve will no longer be manual.

⁸ For example, facilities ALBANY_WF1, ALINTA_WWF, BADGINGARRA_WF1, EDWFMAN_WF1, GRASMERE_WF1, INVESTEC_COLLGAR_WF1, and MWF_MUMBIDA_WF1.

⁹ For example, facilities COCKBURN_CCG1, NEWGEN_KWINANA_CCG1, and PPP_KCP_EG1,

¹⁰ For example, facilities NAMKKN_MERR_SG1 (2 turbines), NEWGEN_NEERABUP_GT1 (2), PERTHENERGY_KWINANA_GT1 (2), PRK_AG (3), and STHRNCRS_EG (4)

¹¹ It can also be set based on the single largest network contingency, where multiple generators are impacted and the aggregate MW loss sets the reserve requirement.

The SCED market clearing engine (MCE) must receive offers at sufficient granularity to match the real trade-offs as closely as possible, and determine physically feasible dispatch schedules for each facility.

Generally, it is the characteristics of the individual generation system that dictate the combinations of energy and essential system services that a facility can provide simultaneously, rather than the combined characteristics of all generating systems at that location. Two 100 MW facilities have significantly different ability to provide contingency reserve than one 200 MW facility. Similarly, the requirement for contingency reserve is driven by the definition of credible contingencies.

In most cases, the credible contingency is the loss of the generation from an individual generating unit, not the loss of the injection from an aggregated facility. However, it is possible for an aggregated facility to affect essential system service requirements where the individual facilities would not have. In such a case, the MCE may schedule more contingency reserve or, in order to avoid scheduling additional contingency reserve, dispatch the aggregated facility to a lower energy quantity than it would have, had the facilities been offered separately. This would increase the overall cost of dispatch.

For these reasons, the SCED market will be less able to accommodate facility aggregation than the current WEM. However, no facilities currently offering on an aggregated basis are expected to have to move to individual facility offers.

Design approach – Offer aggregation

The Taskforce has adopted the following approach.

- Require facility owners to provide data to AEMO for each individual facility.
- Allow facility aggregation at AEMO's discretion where the individual facilities inject at the same network location and:
 1. none of the individual facilities will provide essential system services, and the small size of the aggregation means it is unlikely to affect the quantity of essential system services dispatched; or
 2. capability to simultaneously provide energy and essential system services from the individual facilities can be adequately described as an aggregated facility, and the small size of the aggregated facility means it is unlikely to affect the quantity of essential system services dispatched; or
 3. the relevant credible contingency is the loss of the network connection to all individual facilities simultaneously, rather than the loss of a single individual facility; or
 4. the aggregated facility would comprise generation systems that are dependent on each other, such that there is a credible contingency of losing more than one individual facility at once (for example combined cycle generators).

Design approach - Dispatch aggregation

Notwithstanding the requirement in most cases to submit offers for individual facilities, it is possible to allow participants flexibility to choose how to distribute required generation across multiple facilities at the same location.

The MCE will calculate dispatch for facilities at whatever level of granularity is present in offer data. Where facilities are offered individually, the MCE will calculate dispatch individually. Where offers are for an aggregated facility, the MCE will calculate dispatch for the aggregated facility.

Where individually offered facilities have the same owner and the same location, they can be aggregated into a 'station dispatch group', and AEMO can issue a dispatch instruction for the sum of the dispatches of the individual facilities.

Under the Taskforce's approach, participants would be required to do the following.

- Manage the total aggregate generation for the group to meet the total sum of the dispatched quantities for each constituent facility. Any departure from that quantity would be a dispatch non-compliance, and would be met from load following services, increasing overall market costs.
- Manage the generating plant within the group so as to ensure the injection from any individual facility does not exceed the injection of the facility that sets the relevant contingency risk for the dispatch interval. If a facility breached this limit and then tripped, there would not be sufficient contingency reserve to replace it.

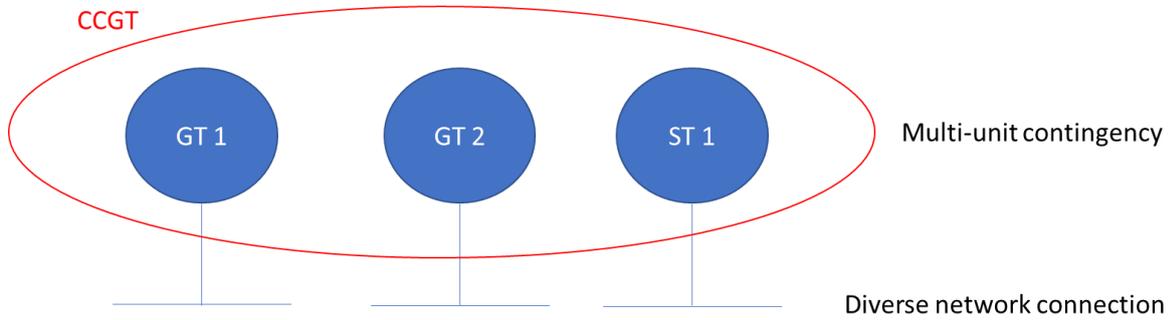
Implementing this capability will slightly increase the complexity of the settlement system, particularly around essential system service cost recovery and constrained payments.

Contribution to WEM Objectives

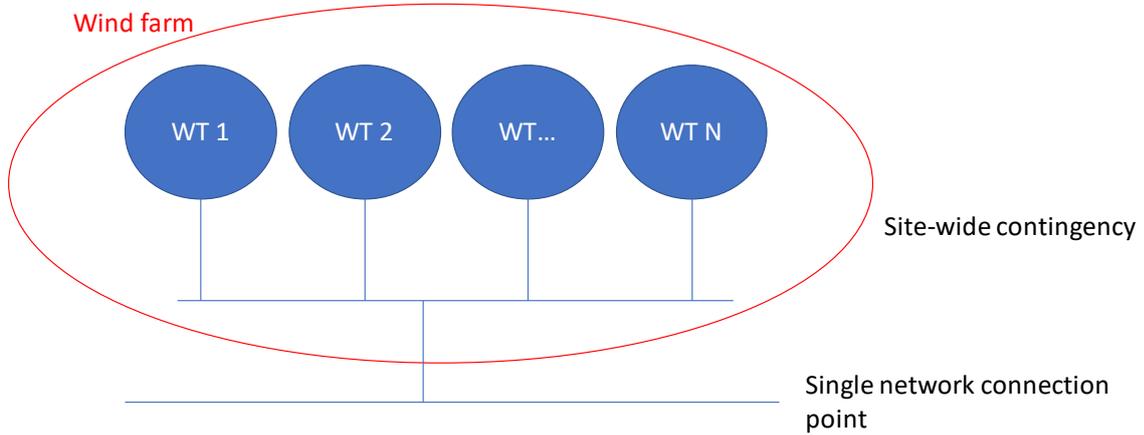
	Objective	Contribution
1.2.1(a)	Promote economically efficient, safe and reliable production and supply of electricity in the SWIS	Contributes to efficiency and reliability by avoiding under-procurement of essential system services
1.2.1(d)	Minimise the long-term cost of electricity supplied to SWIS customers	Contributes to lower costs by avoiding over-procurement of essential system services

Examples

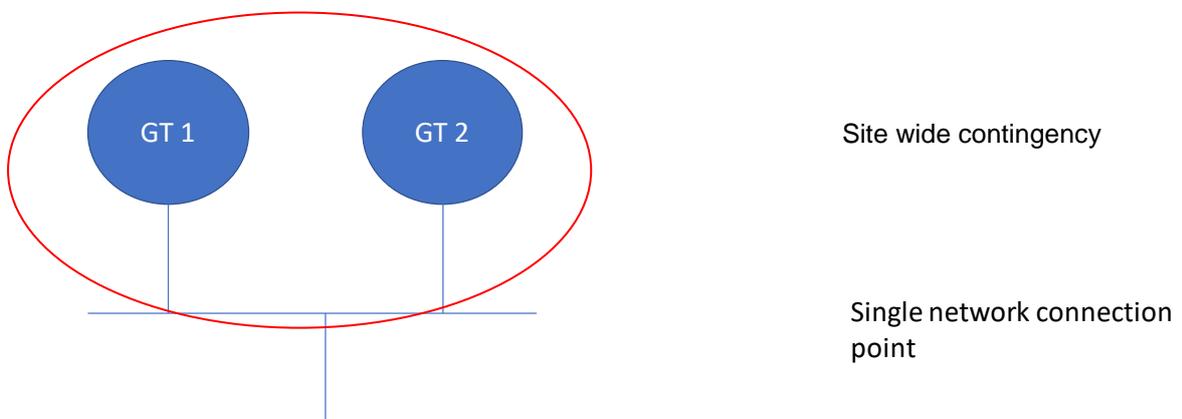
Aggregation example 1: CCGT - Aggregation mandatory

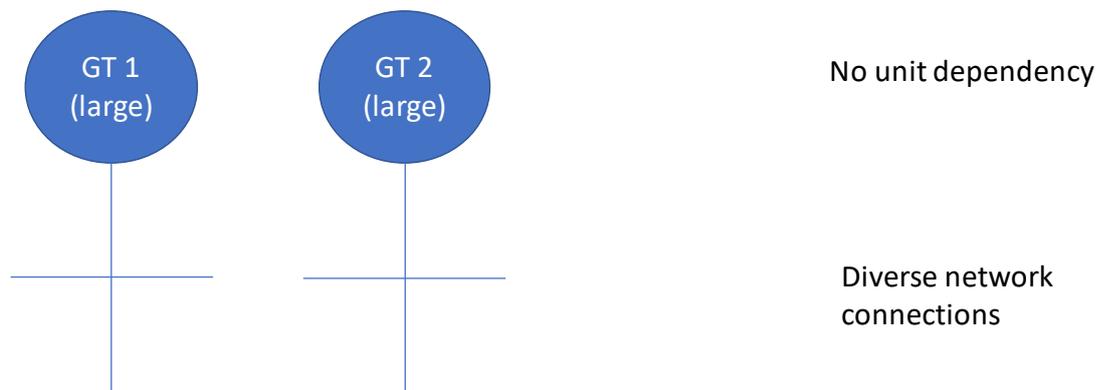
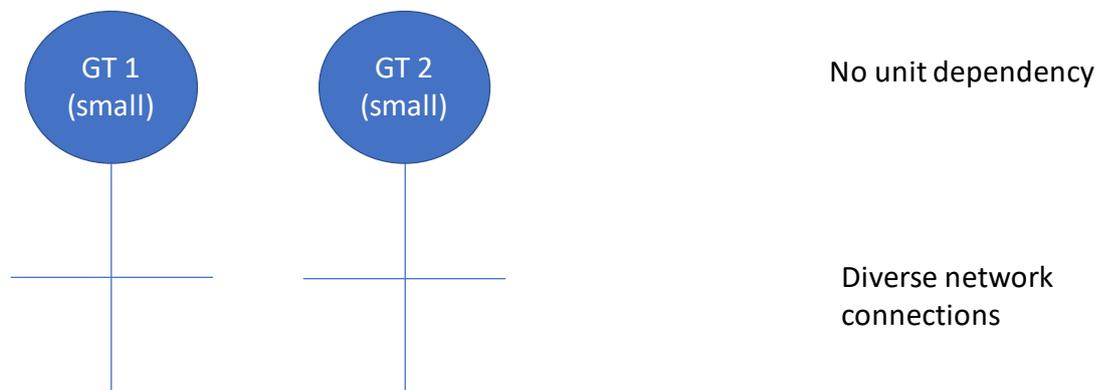


Aggregation example 2: Wind farm - Aggregation mandatory



Aggregation example 3: Two large units with a single connection - Aggregation mandatory



Aggregation example 4: Multiple large units with diverse connection - Aggregation not allowed**Aggregation example 5: Multiple small units with diverse connection (but same electrical location) - Aggregation optional, at AEMO's discretion****3.1.2 Gate closure**

Gate closure is the point in time at which participants are no longer allowed to make changes to their market offers. It is described in terms of time before the start of the dispatch interval for which the offers are made.

Current approach

In the current market, AEMO needs time to align the unconstrained Balancing Merit Order (BMO) with network and security constraints, to translate the BMO cleared volumes for the Synergy portfolio to facility-level dispatch, adjust Synergy unit commitment and potentially ramp Synergy facilities into position for the next trading interval. To allow time for AEMO to carry out this activity, participants may not change their offer prices or quantities within two hours of the start of the trading interval.

Similarly, because participants must reflect the results of the LFAS market in their energy offers, the LFAS market must be cleared ahead of energy market gate closure, and LFAS gate closure is significantly ahead of real time.

The current market design is a 'hybrid' design, where the dispatch of Synergy facilities is within the discretion of AEMO (as System Manager). Synergy submits a portfolio supply curve with an earlier gate closure, giving AEMO certainty over what is available, and giving other participants an opportunity to submit their positions in relation to the portfolio offers. Advanced gate closure arrangements for the Synergy portfolio also act to mitigate market power, by allowing market participants to react to the forecast schedule without having to consider potential changes that Synergy might make.

Currently:

- For facilities other than the Synergy Portfolio:
 - energy gate closure is 2 hours;
 - LFAS gate closure is between 5 hours and 10.5 hours;¹² and
 - participants may only amend energy offer quantities (not prices) after gate closure in cases where a facility suffers an outage, or its available capacity is otherwise constrained.
- For the Synergy portfolio:
 - energy gate closure is between 4 hours and 9.5 hours;¹³
 - LFAS gate closure is between 8 hours and 15.5 hours; and
 - Synergy may only amend energy offer quantities (not prices) after portfolio gate closure if a portfolio facility suffers an outage or its available capacity is otherwise constrained, and may not amend energy offer quantities after general market gate closure.¹⁴
- Participants must provide an explanation for amendments after gate closure.
- There is no allowance for updates to LFAS offers after gate closure. If a facility is scheduled for LFAS and cannot provide it, it will be provided by the portfolio as backup LFAS.

Under these arrangements, participants make most of their submissions at the last possible opportunity. Of the approximately 34,000 submissions made from 1 December 2017 to 1 December 2018, more than half were in the five-minute period immediately before gate closure, as reflected in **Table 1**.

¹² There are four LFAS gate closures each day, each for a group of 12 trading intervals of 30 minutes each.

¹³ Synergy can only update offers for the portfolio four times a day, so offers for trading intervals from 8.00am to 1.30pm must be submitted by 4.00am

¹⁴ Noting that WEM Rule change proposal RC_2013_15 proposes to allow Synergy the capability to adjust energy offer quantities for forced outages within gate closure when this is likely to unexpectedly impact the dispatch of another facility (i.e. when capacity is getting tight).

Table 1: Offer submissions by time period¹⁵

Period	Percentage of submissions
<5 mins to gate closure	53 per cent
>5 and <25 mins to gate closure	13 per cent
>25 mins to gate closure	34 per cent

While this behaviour is undesirable (participants are submitting large volumes of offers without knowing what other participants are changing at the same time), it is understandable, as participants seek to make use of the most recent forecast information in a timeframe where the load forecast can still be changing significantly.

Future state

General approach to gate closure

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, later gate closure allows market participants to make decisions closer to real time, with the benefit of more accurate forecasts (including forecasts of electricity demand and intermittent generation) and up-to-date knowledge of network conditions and the status of generation facilities (including outages).

Theoretically, gate closure should be as close as possible to real time in order to maximise participants' ability to respond to new technical and market information and, therefore, increase the overall efficiency of dispatch. If participants can offer closer to real time, they can:

- adjust offers to avoid being dispatched to an unachievable target, based on more accurate forecasts;
- be more flexible during commissioning and testing processes;
- more easily facilitate the start-up or shut-down profile of a large facility; and
- use the full flexibility of new storage technologies to respond to real-time grid conditions. In particular, any non-zero gate closure will impede the ability of battery storage to respond to short-term system volatility.

There is significant opportunity for participant offers to be made with better understanding of actual outcomes. AEMO data in **Table 2** and **Figure 2** shows the scale of the reduction in forecast error closer to real time. The expected error roughly halves between 150 minutes

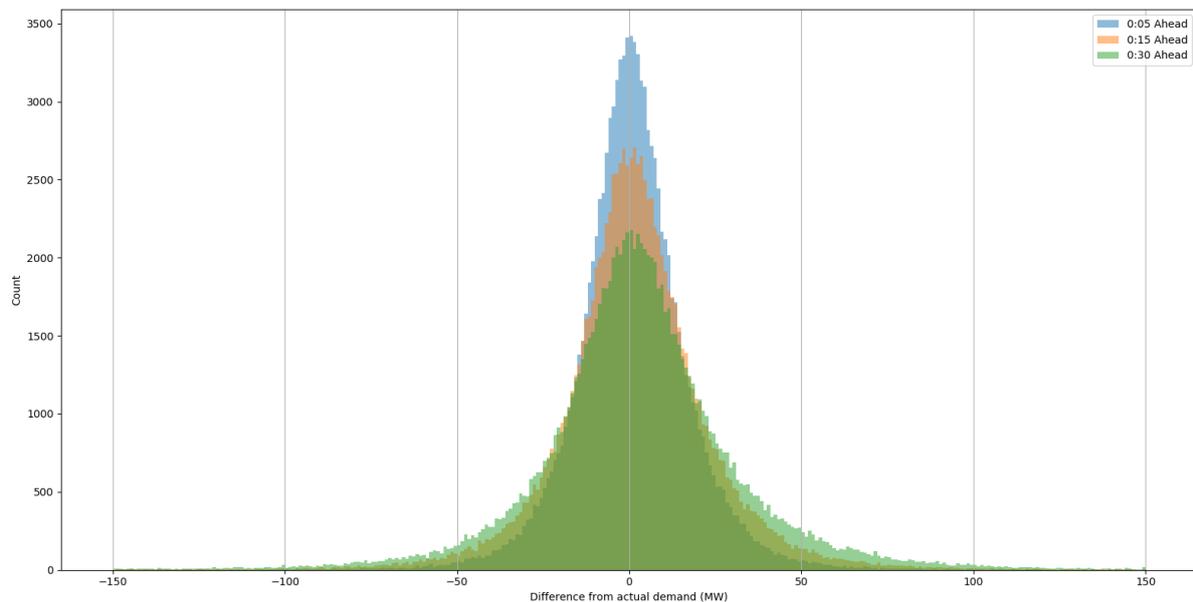
¹⁵ Source: AEMO analysis.

and 30 minutes ahead of real time, and nearly halves again between 30 minutes and five minutes ahead.

Table 2: Short term load forecast accuracy (95% confidence interval)

Minutes ahead	Lower bound (MW)	Upper bound (MW)
150	-136	136
30	-60	65
15	-45	48
5	-33	34

Figure 2: Forecast error at various points ahead of real time – January-December 2018



The current need for a non-zero gate closure is largely driven by the need for time to account for network constraints and power system security issues arising from the WEM's current hybrid market design and unconstrained dispatch model. With the introduction of a security constrained, co-optimised MCE that includes consideration of the network, generator ramping capabilities and facility dispatch for Synergy, the need to reserve time before dispatch should be greatly diminished.¹⁶

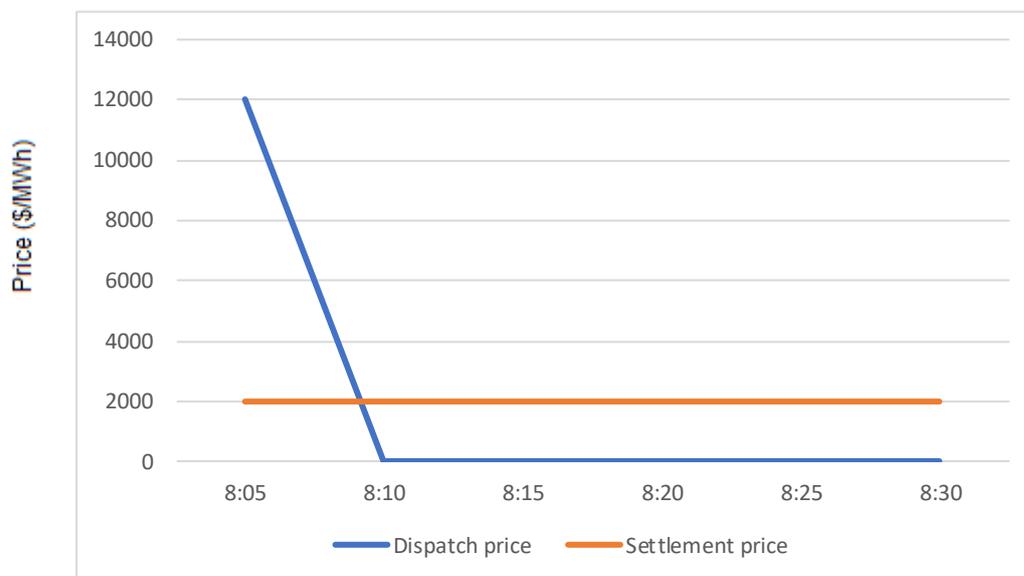
¹⁶ There may still be times in which a late offer change can create a security issue that can only be resolved by committing a facility that is currently off-line, but it is difficult to gauge the likelihood of such an occurrence. In some cases, late bid changes could also result in other facilities being dispatched to positions that they may otherwise normally not be able to achieve (i.e. at a point lower than their minimum generation).

If the dispatch interval has a different length than the trading interval, late gate closure can result in undesirable interactions. Experience in the National Electricity market (NEM), where the dispatch interval is five minutes, the trading interval used for settlement is currently 30 minutes, and there is no gate closure,¹⁷ participants can re-offer after the start of a trading interval. This can give rise to the 5/30 minute anomaly shown in **Figure 3**, where settlement prices can be much lower than one or more of the corresponding dispatch prices.¹⁸ 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 price that is lower than the generator's offer price and does not allow the generator to recover its short-run costs. The risks for a peaking generator are increased by the ability of other generators to alter their dispatch offers after the start of a trading interval, which can greatly reduce dispatch prices for subsequent dispatch intervals and so the final spot price.

The magnitude of this effect would be mitigated to some extent with the current WEM price cap settings, as shown in

Figure 4.

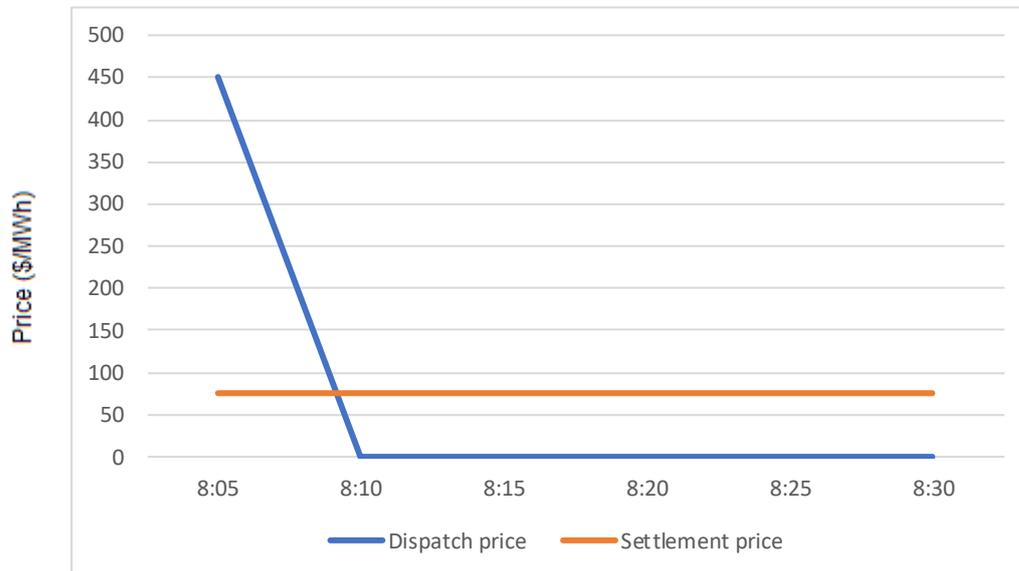
Figure 3: 5/30 minute anomaly with a high dispatch price in DI1, and zero price in DI2-6, NEM



¹⁷ The gate closure for changes to offer tranche prices is 24 hours in advance, but quantities can be moved between offer tranches at any time. Effectively, gate closure occurs a minute or so before the start of the dispatch interval, when the MCE generates the dispatch based on the latest offers available.

¹⁸ In November 2017, the Australian Energy Market Commission made a rule to change the settlement period for the electricity spot price to five minutes from the current 30 minutes starting in July 2021. This will remove the 5/30 minute anomaly in the National Electricity Market.

Figure 4: 5/30 minute anomaly with a dispatch price near the current WEM price cap in D11, and zero price in D12-6



The other manifestation of undesirable behaviour resulting from a short or zero gate closure would be a participant continuing the current practice of significant re-offer volumes in the last minutes before gate closure. Shorter gate closure should significantly reduce the need for legitimate instances of such behaviour, as participants have more certainty of outcome through more accurate forecasts.

This behaviour can be effectively mitigated by adopting good faith offering obligations, making offer data public after the fact, and carrying out ex-post market monitoring activities to detect and sanction manipulatory behaviour. Any significant last-minute offer changes (by any participant) would be clearly discernible through market monitoring, so this method of exercising market power would be relatively simple to detect and sanction.

The questions of settlement interval length, compliance monitoring and enforcement, and price cap settings will be examined in later design papers.

Advanced gate closure for Synergy

As part of the current hybrid market design, the Synergy portfolio is subject to an earlier gate closure than other facilities. The current rules provide a mechanism for Synergy to have an individual facility removed from portfolio offering and System Management discretionary dispatch by having it declared a 'stand-alone facility'. Such a facility would be treated the same as any non-Synergy facility, including being subject to the two-hour gate closure and facility level dispatch via the BMO.

With a move to facility bidding the existing hybrid market design will be superseded and the Synergy portfolio removed from the Market Rules, thereby removing the technical reasons for treating Synergy facilities differently from others.

Nevertheless, Synergy will continue to make up a significant portion of market capacity for some years to come, which raises the question of retaining an advanced gate closure for market power mitigation purposes. Synergy makes up a large enough proportion of the market that last-minute changes to offers for several of its facilities could significantly change dispatch outcomes from what was forecast, without other participants having an opportunity to adjust their offers. On the other hand, restricting the ability of a significant number of facilities to respond to changing market conditions is likely to reduce the efficiency of dispatch, and increase overall costs to consumers. In particular, an earlier gate closure for Synergy would impose a delay on Synergy facilities returning from maintenance, which does not exist today. In many cases this would require the dispatch of other, more expensive facilities, increasing the overall cost of supply.

With more flexible market systems and more transparency of network and security impacts on dispatch, participants will have better visibility of market dynamics and forecast outcomes, meaning that the impact to other participants of changes in Synergy's offers will be clearer more quickly.

Facility bidding means that Synergy's offering behaviour will be more transparent, better supporting ex-post monitoring, analysis and potential sanction. As for other participants, last-minute offer changes by Synergy would be clearly recognisable, and could be subject to sanction if not well justified.

Design approach

It is clear that unlocking the flexibility of new technology requires gate closure (for both prices and quantities) to be reduced as far as possible. Nevertheless, the uncertainties about participant behaviour and system operation implications mean that it would not be prudent to implement a zero-gate closure on day one. The Taskforce therefore will implement a staged approach as follows.

- Adopt a 15-minute gate closure at the commencement of the SCED market.¹⁹
- Allow a minimum six-month 'bedding in' period, during which AEMO can assess the actual volatility of market results and the need for a gap between gate closure and real time.
- Retain the ability for intermittent generators to submit within gate closure, to support accuracy of market dispatch.
- Automatically reduce gate closure to zero after six months, unless:
 - AEMO identifies a significant and quantifiable risk to system security, or
 - there is a significant volume of offers just before gate closure, such that market dispatch is changing significantly at the last minute.
- Subject all participants to the same gate closure rules, regardless of market share.

¹⁹ As in the current market, the restriction would be a paper one. Market systems will still accept offers submitted at any time. If a participant made a submission inside the 15-minute gate closure period (breaching the market rules), it would be accepted and used in the MCE.

- Implement good faith offering obligations, supported by ex-post market monitoring activities.
- Allow the Economic Regulation Authority (the body responsible for monitoring compliance) to assume bad faith where a participant shows a pattern of significant last-minute changes that distort market outcomes.
- Make offer submissions (including prices and all revisions) public after real time, by the end of the following trading day.

Contribution to market objectives

	Objective	Contribution
1.2.1(a)	Promote economically efficient, safe and reliable production and supply of electricity in the SWIS	Zero gate closure maximises market participant flexibility, increasing overall efficiency
1.2.1(b)	Encourage competition, including facilitating efficient entry of new competitors	Zero gate closure encourages entry of new flexible technologies, particularly energy storage
1.2.1(c)	Avoid discrimination against particular energy options and technologies, including sustainable energy options	Same gate closure for all participants means all parties play by the same rules
1.2.1(d)	Minimise the long-term cost of electricity supplied to SWIS customers	Ability for facilities to return from outage in a shorter timeframe allows lower-cost generation to displace higher-cost generation, reducing overall cost of supply Reduce risk premiums in market offers as a result of more accurate forecasts

3.1.3 Intermittent generation offers

Current approach

The WEM rules define an Intermittent Generator as a generator *‘that cannot be scheduled because its output level is dependent on factors beyond the control of its operator’*. The current market clearing regime treats intermittent generators as active participants as far as possible, and makes allowances for the special characteristics of their operation.

Intermittent generators (primarily wind and solar) offer into the BMO with a single price-quantity pair, on the assumption that all output is associated with a single, static price per MWh below which they would be prepared to curtail output.

Intermittent generators can set the marginal price, and their generation may be restricted in dispatch in accordance with their position in the merit order. If their offered price is lower than the cleared market price, they will be allowed to inject whatever they can (subject to network and security considerations, and to demand requirements if they are the ‘marginal’ unit setting

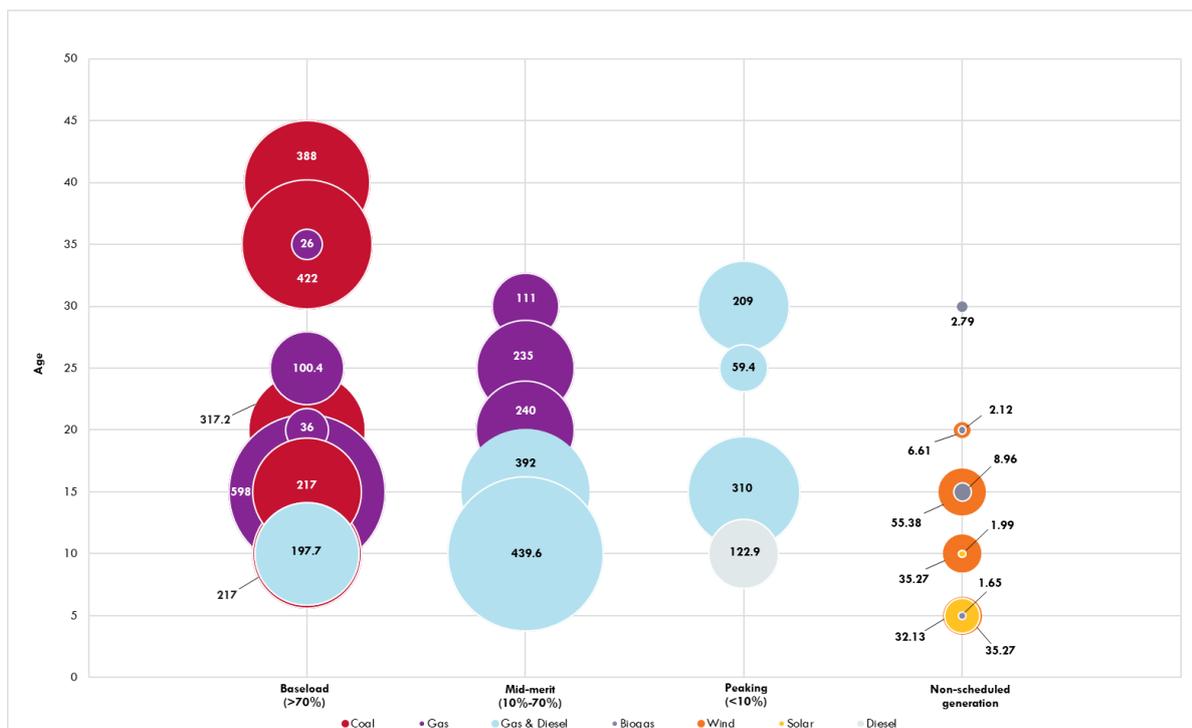
price). If their offered price is higher than the cleared market price, they will be dispatched in accordance with demand requirements (including down to zero).

Future state

Some markets around the world require intermittent generators to be purely price takers, by not allowing them to offer into the market, or requiring them to offer at zero price. This ignores the fact that the variable cost of generation from an intermittent generator, while low, is not zero. It can vary as weather conditions change, and it can vary depending on the level of output even where weather conditions do not change. Further, if an intermittent generator receives other revenue linked to its output (such as revenue from the sale of Large-Scale Generation Certificates²⁰), its preference to be cleared in the energy market can also change.

Figures from AEMO's *2018 Electricity Statement of Opportunities* show the ongoing increase in the renewable (wind and solar) component of the WEM generation fleet. All new generation in recent years has been renewable.

Figure 5: Facilities operating in the SWIS by age, fuel capability, and classification²¹



While the proportion of wind and solar generation in the generation fleet has increased substantially over recent years and is likely to continue to do so, the intermittency of such generation is likely to decrease in future. Developments in control systems and storage

²⁰ <http://www.cleanenergyregulator.gov.au/RET/Scheme-participants-and-industry/Power-stations/Large-scale-generation-certificates>

²¹ AEMO, 2018, Electricity Statement of Opportunities, accessed at: https://www.aemo.com.au/-/media/Files/Electricity/WEM/Planning_and_Forecasting/ESOO/2018/2018-WEM-ESOO-Report.pdf

technology mean that future wind and solar developments will have more ability to control their output to the grid through the firming capability of co-located storage and advanced control systems. This, combined with a five-minute dispatch interval and ability to re-offer right up to real time, means that such facilities may be able to meet the definition of a Scheduled Generator.

Nevertheless, in the short to medium term, the proportion of intermittent generation will continue to rise, intermittent generators will be marginal more often, and, where they can be treated the same as other forms of generation, doing so will smooth the path to scheduled wind and solar.

Design approach

Therefore, intermittent generators will continue to have the ability to offer non-zero prices, can set the market price where marginal, and have the option to offer using the same number of tranches as scheduled generators, where the sum of the offered quantities is their forecast output.

Contribution to market objectives

	Objective	Contribution
1.2.1(c)	Avoid discrimination against particular energy options and technologies, including sustainable energy options	Increases flexibility for intermittent generation to participate in market processes

3.1.4 Treatment of smaller facilities

In the current market, registered facilities with rated capacity of less than 10 MW have the option of participating in the real-time market, even where they do not have the capability to receive or respond to electronically issued dispatch instructions. They are allowed to function as self-scheduled facilities, and required to structure their offers such that their expected dispatch is offered at the offer price floor, and the remainder of their capacity at the offer price cap. Having these facilities participate in the real-time market provides visibility of their output to AEMO, better forecast accuracy for market participants, and greater transparency about what is happening on the power system. Without this inclusion, the output of small facilities would be combined into the non-scheduled generation forecast, with a corresponding reduction in the accuracy of market pre-dispatch schedules.

Some small facilities can receive and respond to electronically issued dispatch instructions in current market timeframes via manual processes. The move to a five-minute dispatch interval (with dispatch instructions issued only a minute or two before the start of the interval) will reduce the time available for manual action to the point where it will no longer be feasible. This will increase the number of small facilities that cannot participate fully in the real-time market, increasing the importance of having a mechanism to allow their expected output to be signalled.

The approach of allowing participation in the real-time market, but applying offer restrictions to ensure market scheduling and dispatch reflects self-scheduling decisions is still viable in a

SCED market. Alternatively, such facilities could provide a forward schedule to AEMO, for inclusion in the non-scheduled generation forecast.

Design approach

The approach is to allow small facilities that cannot respond to electronically issued dispatch instructions to request participation in the real-time SCED as follows.

- Expected dispatch (or forecast output) to be offered at the offer price floor.
- Remainder of capacity for scheduled generators to be offered at the offer price cap.
- Subject to ex-post dispatch compliance monitoring, rather than real-time monitoring by AEMO control room.
- Or as otherwise specified in a market procedure.

Contribution to market objectives

	Objective	Contribution
1.2.1(a)	Promote economically efficient, safe and reliable production and supply of electricity in the SWIS	Participation of small generators in market processes increases accuracy of forecasts, supporting reliability of power system operations and efficient decision making by other participants

3.1.5 Mandatory offer obligations

Current approach

In most markets, participants are free to choose to participate or not, both in the long-term (through investment in plant and facilities) and in the short-term (through offering to buy or sell products or services).

The real-time energy market is the mechanism that matches the least-cost combination of electricity supply to the projected demand. In a gross pool market such as the WEM, the central market operator calculates this least-cost dispatch, and the system operator implements it (having regard to any security considerations that are not included in the market clearing algorithms).

The gross pool model allows full optimisation of the whole (participating) fleet, and supports secure system operations by making dispatch subject to instruction from the power system operator.

In an energy-only electricity market, participants are still generally free to choose, in any given interval, whether to participate by making offers to supply. They are free to withhold capacity from the real-time market should they wish to do so, and where doing so does not fall foul of general competition law (i.e. where done in an attempt to manipulate market prices).

In an electricity market with a long-term capacity mechanism, the market design recognises a risk of insufficient supply in real-time if capacity is not procured on a longer-term basis. By definition, facilities receiving capacity revenue are necessary to ensure reliability of supply. For this reason, facilities that receive capacity payments are generally required to offer the associated capacity into short-term markets.

The WEM sits alongside PJM and New England as a gross pool market where capacity mechanism outcomes are linked to short-term market offer requirements.²² Participants must make the capacity associated with capacity credits available in the STEM, and are free to offer or not any capacity over and above their capacity credits.

Unusually, the Balancing Market has had a must-offer rule for all capacity since market start in 2012. Balancing submissions must accurately reflect participants' reasonable expectation of the capability of their facilities to be dispatched, and any capacity not offered must be subject to a formally notified outage. Participants are free to offer at the price cap if they wish to be dispatched only in extremis.

Participants who do not comply with the requirement to offer into STEM pay reserve capacity refunds. Participants who do not comply with the requirement to offer into the Balancing Market can be ordered to pay civil penalties. Rule change proposal RC_2013_15 will link the Balancing Market must-offer requirement directly to capacity credits (and therefore refunds).²³

In line with the self-commitment principle (section **Error! Reference source not found.**), the current implementation of the BMO does not consider the synchronisation status of a facility. This means that it is possible for a facility to become in-merit or marginal, and receive a dispatch instruction for a timeframe that is too short to respond to. The current WEM Rules only require AEMO to consider standing data limitations, such as start times, when dispatching a facility out-of-merit. The current WEM dispatch engine does not consider start time limits when dispatching facilities, as this information is not available to it under the current market design.

Future state

The primary purpose of the RCM is to ensure availability of supply in times of system stress. The Planning Criterion is set to ensure there is enough installed capacity to supply the expected system peak demand, as well as sufficient energy across the year to satisfy the requirement to limit unserved energy to below 0.02 per cent. The requirement to offer is the key mechanism by which RCM outcomes are translated into real-time availability.

The requirement to offer all capacity into the real-time Balancing Market goes beyond this, placing the same obligation on all participants regardless of their RCM participation. A facility without capacity credits is, by definition, not required to satisfy the reliability standard within the Planning Criterion and receives no capacity compensation.

²² Facilities cleared in the PJM capacity mechanism must offer into the day ahead market, and New England places a requirement to offer into both day-ahead and real-time markets.

²³ Available at: https://www.erawa.com.au/rule-change-panel/market-rule-changes/rule-change-rc_2013_15

In future, projected network constraints will be incorporated into capacity certification processes. Over time, this will see the capacity credits assigned to each facility disconnect from the nameplate capacity, and potentially a larger proportion of systemwide capacity not covered by capacity credits.

Issues around dispatch of facilities that are not currently synchronised may be exacerbated in a SCED market, as the MCE is more likely than current manual processes to seek to relieve constraints by dispatching facilities offering at the offer price cap.

One approach to prevent this would be to remove the requirement to offer into the real-time market for facilities that are not currently synchronised and not intending to synchronise. This would allow the MCE to have an accurate view of which facilities are available and remove the possibility of it generating a dispatch instruction to a facility that could not respond. Doing so would support more accurate real-time dispatch calculations, but would reduce the accuracy of pre-dispatch prices, and would require an alternate mechanism to monitor availability of unsynchronised facilities.

Availability submissions

The approach adopted is that facility offers indicate the availability status of its capacity in each of three operating states.

- In-service
- Available
- Unavailable

In-service capacity is available to respond to Dispatch Instructions. This includes capacity from synchronised facilities, and from unsynchronised facilities that have submitted offers with inflexibility profiles (see section **Error! Reference source not found.**). An in-service facility must ensure that all its capacity that is not unavailable is offered into the real-time market, subject to its capacity credit holdings.

Available capacity is not currently synchronised, but would be available for dispatch if it was given notice in accordance with start times in its standing data. A facility in this state is required to offer into the real-time market, but its offers will not be included in the market dispatch schedule – it will appear in pre-dispatch results, but will not receive dispatch instructions. Available capacity would be required to pay capacity refunds if it failed to respond to a direction from AEMO, or if it was otherwise determined to be unavailable.

Unavailable capacity is on an outage or otherwise out-of-service. It would not be available for dispatch, even if given notice in accordance with start times in its standing data. Unavailable capacity would be required to pay capacity refunds unless on an approved refund-exempt outage.

A facility could designate part of its capacity available and part unavailable, or could designate part of its capacity in-service and part unavailable. Capacity refunds would be calculated based on the total available and in-service capacity in each interval.

A facility cannot have both in-service and available capacity for a given dispatch interval, unless:

- it is an aggregated facility with units in different states of synchronisation; or
- it is a dual-fuelled facility and is running on a fuel that does not allow it to reach its maximum certified output. The additional volume achievable with a change of fuel would be offered as available, and the time required for fuel changeover reflected in standing data.

If a facility constantly offered as available in pre-dispatch, forecast to run as it was in-merit, but then chose not to synchronise, it may be cause for investigation through market monitoring.

Design approach

The approach will be to:

- retain the obligation for facilities holding capacity credits to offer at least that much capacity into the STEM and real-time energy market²⁴;
- align with the changes introduced in RC_2013_15 to not require capacity not covered by capacity credits to offer into the real-time energy market;
- introduce availability categories in offers to allow participants to signal availability without risking being dispatched with less notice than their minimum start-up time;
- investigate options for AEMO intervention on pre-dispatch and PASA²⁵ timeframes and the role of capacity obligations to ensure security/reliability outcomes are met;
- retain AEMO's powers of emergency direction to facilities, regardless of capacity credit holdings

This means that Reserve Capacity Mechanism obligations will continue to flow through to offer obligations for both STEM and real-time. The process for calculating a specific Facility Reserve Capacity Obligation Quantity will be addressed in the separate RCM workstream.

Contribution to market objectives

	Objective	Contribution
1.2.1(a)	Promote economically efficient, safe and reliable production and supply of electricity in the SWIS	Must-offer rules ensure capacity is available when needed, contributing to system reliability Availability states ensure the clearing engine has accurate data on actual system capability, while

²⁴ There is no need for participants to structure their offers to account for network constraints, as those will be automatically dealt with by the new SCED market clearing engine. Each participant can offer its full capability at its local injection point.

²⁵ Projected Assessment of System Adequacy, which is performed by AEMO over short-term, medium-term and long-term time horizons.

		not dispatching facilities that cannot respond
--	--	--

Example

The table below provides some scenarios to explain the above state. Assume that Facility A is a 100 MW generator with 100 Capacity Credits, and a two-hour cold start time. The following events occur, as summarised in **Table 3**.

Facility A is currently not synchronised, but is available if given two-hours notice.

In response to forecast high prices at 12:00, Facility A begins the synchronisation process and bids itself into the real-time market for its full quantity (100 MW) from 12:00 at several price-quantity pairs.

At 13:00, the facility suffers an unplanned partial outage, reducing its dispatchable capacity to 50 MW. It continues to bid the remaining 50 MW of capacity. The 50 MW of capacity that suffered the outage will attract reserve capacity refunds.

At 15:00, the facility adjusts its offers to be out-of-merit, is dispatched to 0 MW, ramps down and desynchronises. 50 MW is still unavailable from the earlier unplanned partial outage, but 50 MW is available to dispatch if given appropriate notice by AEMO. 50 MW will be still attracting reserve capacity refunds, but 50 MW will still be considered available, and will not attract refunds.

Table 3: Example Market State of a Facility's capacity (MW) in certain Dispatch Intervals

Facility State	Dispatch Interval			
	08:00 to 11:55	12:00 to 12:55	13:00 to 14:55	15:00 onwards
In-service	0	100	50	0
Available	100	0	0	50
Unavailable	0	0	50	50

3.1.6 Fast start inflexibility profiles

Current state

In the current WEM, commitment decisions for Synergy facilities are made by AEMO System Management. Other participants must structure their offers so as to make their own commitment decisions.

Facilities that wish to be committed will typically offer their must-run quantities low in the BMO (often at the minimum STEM Price). This means that, barring exceptional circumstances, the facility will be dispatched for the quantity required to ensure its stable operation. Any additional available capacity can then be bid at an appropriate price and dispatched accordingly.

As discussed in section 3.1.5, changes to load forecast, intermittent generation and facility outages between the final BMO and real-time can result in facilities being called upon when they did not expect to be. They would then be required to turn on and ramp to their dispatch target in the 15 to 40 minute window between being issued the dispatch instruction and the end of the trading interval.

Similarly, depending on offer structure, they may be issued a dispatch instruction for an amount lower than their minimum running. If a facility is dispatched and cannot respond, it faces penalties for dispatch non-compliance, as well as being required to lodge a forced outage and pay capacity refunds.

This tends to occur infrequently in the WEM at present. When it occurs, AEMO needs to manually intervene to ensure that the next cheapest generator that can respond is dispatched in preference to a facility that cannot synchronise in time, or operate at the level indicated in its dispatch instruction.

At present, AEMO manually projects ahead in time to make sure that any Synergy facilities required are committed and available to meet their expected dispatch. AEMO makes relatively few dispatch instructions to non-Synergy facilities that they cannot comply with. In the period from 1 January 2016 to 28 February 2019, AEMO issued around 140,000 dispatch instructions, but only around 0.1 per cent of instructions were to a level that a facility was unable to meet²⁶.

Future state

With the move to facility offers for all participants, AEMO will no longer have discretion to commit Synergy facilities in normal system operations. The shortened dispatch interval will reduce the window for a facility to respond in, and the incidence of dispatch instructions that facilities are unable to meet is likely to increase. Synergy is often the owner of the marginal facility, and several of its facilities are the kind of fast start unit that is likely to be legitimately dispatched at short notice.

The changes outlined in section 3.1.5 deal with the issue of dispatch instructions issued for a shorter response time than the facility is capable of, but would also restrict the use of flexible units in shorter time periods.

The fundamental market design principle of requiring participants to make their own commitment decisions means that participants will not submit multi-part offers, and the MCE will not optimise start-up costs or across dispatch intervals. Nevertheless, participants have expressed a desire to have an optional mechanism by which the MCE can reflect the limitations of fast start facilities, along the lines of the NEM's Fast Start Inflexibility Profile (FSIP) regime, to ensure that facilities are able to respond to dispatch instructions.

²⁶ While 0.7 per cent were for less than the facility's declared minimum generation capability in standing data, in most cases, the instructions were to slow-start facilities during their start-up profile, or to facilities that have registered an overly conservative standing data capability that does not match how they offer.

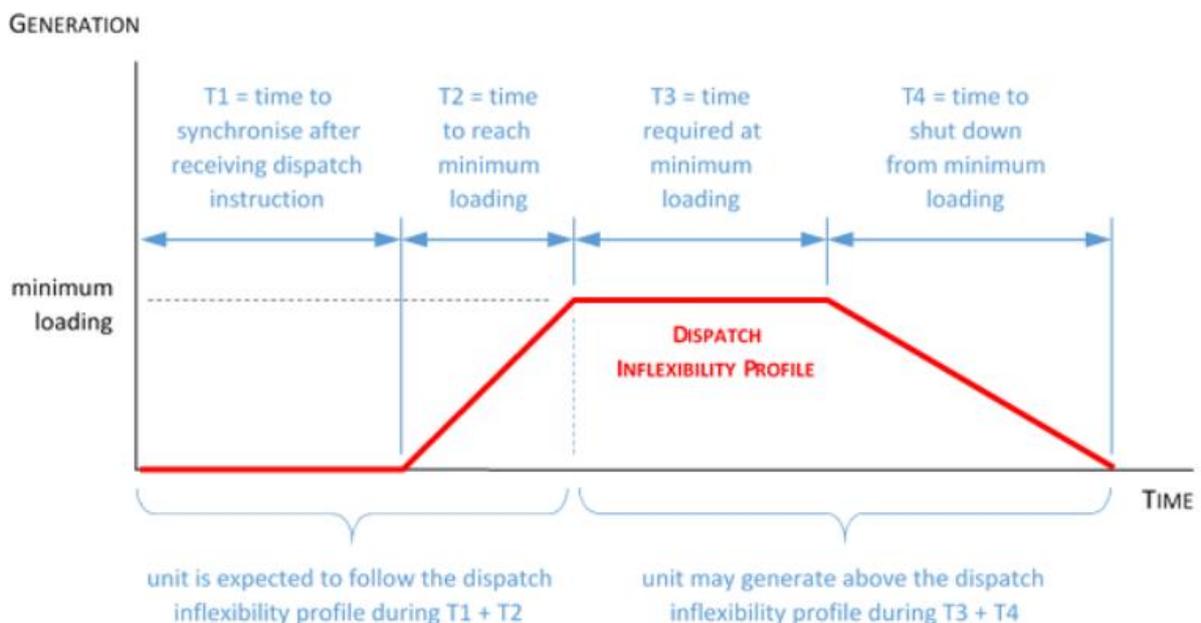
Including such a feature in the reformed WEM would allow owners of flexible facilities to make that flexibility available to the market, while also ensuring the facility is not issued a dispatch instruction that it otherwise could not meet.

Fast start inflexibility profiles in the NEM

In the NEM, any generation facility that cannot synchronise and reach minimum loading within 30 minutes is classed as a 'slow start' generator. These facilities construct their offers to effect their own commitment decisions.

Recognising that the flexibility offered by fast start facilities means that they face more uncertainty of dispatch than slower facilities, the NEM incorporates a limited form of central commitment for units meeting certain criteria. A facility that can synchronise and reach minimum loading within 30 minutes (a 'fast start' generator) may opt to submit an 'inflexibility profile' for inclusion in the dispatch process. The inflexibility profile includes the facility's minimum running level, along with the times required to synchronise, ramp to minimum running, run at (or above) minimum running, and to shut down. To qualify, facilities must be able to go from dispatch instruction to shut down in a maximum time of 60 minutes. This timeframe matches the horizon of the NEM five-minute pre-dispatch schedule.

Figure 2: Characteristics of a dispatch inflexibility profile²⁷



The regime does not replicate the sophisticated central commitment regimes used in other markets, as it does not consider start costs, only physical capability. Whether a facility is scheduled to run still depends on its offer price, but once committed, its start-up profile is

²⁷ AEMO, 2014, *Fast-start Inflexibility Profile: Process Description*, accessed at: http://www.aemo.com.au/-/media/Files/PDF/Fast_Start_Unit_Inflexibility_Profile_Model_October_2014.pdf

respected. The MCE does not consider maximum run time nor maximum or minimum off-time, as these can be managed by the participant in their five-minute offers.

Facilities do not have to opt in to the regime. They always retain the option of remaining in the normal market processes. If they do opt in, they cannot set the market price during the inflexibility period, and become a price taker.

Commitment is only calculated for the immediate next five-minute dispatch interval. That is, if the clearing engine outputs show that one of the fast start units is required to switch on in that very next interval, it is flagged as committed, and the clearing engine is re-run with the pre-set inflexibility profile. If the original MCE solution dispatched the facility to a higher output level than its inflexibility profile, the difference is made up in the second MCE run by another, already running unit.

Because the MCE cannot optimise across trading intervals, FSIP facilities are exposed to price risk. Once a facility is committed, it must complete its start-up process, and if prices drop while it is doing so, the FSIP facility may end up receiving an energy price less than its offer price.

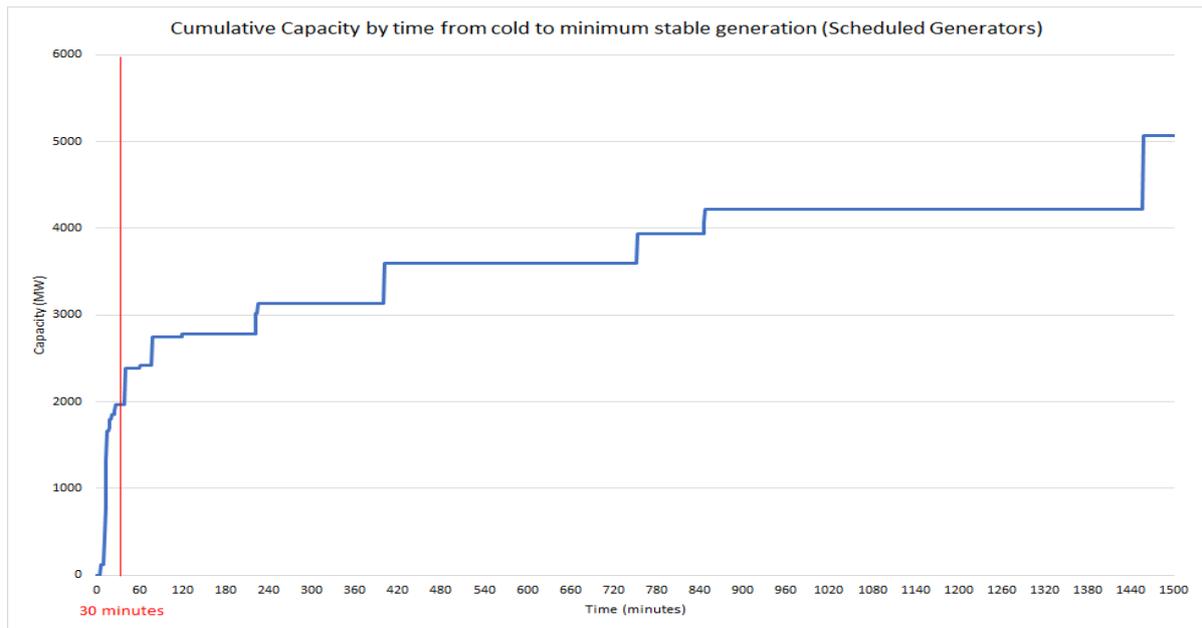
Fast start facilities in the WEM

A large proportion of WEM facilities are likely to meet the ‘fast start’ criteria. Although there are no facilities capable of synchronising and reaching minimum running level within one five-minute dispatch interval, 19 facilities (1600 MW) could reach minimum running level within 15 minutes of an instruction, and another ten (400 MW) could reach it within 30 minutes.

These figures do not include the minimum running and minimum shutdown times, which are not held by AEMO.

Figure 7: WEM generation – time to minimum running level²⁸

²⁸ Source: AEMO analysis



Only two existing facilities fall in the interval between 30 and 60 minutes.

Introducing a fast start commitment approach in the WEM would allow a large number of facilities the option to have their start-up profiles respected at dispatch time, reducing the likelihood of dispatch instructions that cannot be followed, and ensuring this flexible plant can be efficiently used in the real-time market.

Design approach

Allow fast start facilities to opt in to central commitment as follows.

- Facilities must submit a start-up inflexibility profile.
- Inflexibility profiles must reflect the genuine technical capability of the unit – they are a technical aspect of facility capability, not a commercial construct.
- Commitment based on the next-but-one five-minute dispatch interval (as all facilities require at least five minutes to synchronise).
- Fast start facilities operating within their inflexibility profile are not eligible to set the market price until they have reached minimum running.
- Fast start facilities will not be compensated for losses in cases where the market price dips while they are operating within their inflexibility profile.

Contribution to market objectives

	Objective	Contribution
1.2.1(a)	Promote economically efficient, safe and reliable production and supply of electricity in the SWIS	Increases confidence that dispatch instructions will be followed, increasing reliability of the system

3.2 Dispatch and scheduling

3.2.1 Network model for clearing

The 2022 market improvements will increase the temporal granularity of market prices (to every five minutes), but not the locational granularity. The WEM will retain the use of a single system-wide price for the real-time energy market in each dispatch interval. Any complexity arising from the different cost and value of energy at different locations will be reflected in settlement processes, particularly through constrained on 'make whole' payments.

While market pricing does not need to reflect the underlying complexity of the network, SCED requires the network model to be reflected in the dispatch process. The closer the model is to reality, the more efficient dispatch will be, and the fewer manual interventions will be required. The method by which the network model is reflected in the market clearing process is fundamental to success of the market, and is a critical input for the design and implementation of the market clearing engine.

Options for network representation vary in whether network elements are denoted directly in the clearing model or by proxy as constraints on individual facilities. There are three options.

1. Single region hub-and-spoke representation.
2. Multi region hub-and-spoke representation.
3. Full high-voltage network representation.

AEMO has advised that there is likely not sufficient time available before October 2022 to support the introduction of a clearing engine significantly more complex than AEMO's existing NEMDE. The time and effort required to design, procure and build capability in technology new to the market and system operator means that it would not be ready by October 2022 and could potentially be at a higher cost (considering AEMO would also need to implement different downstream market processes and IT support arrangements specifically for the WEM).

For similar reasons, it is not feasible to implement a full model of the high-voltage network in the clearing engine for the 2022 market changes. The NEMDE clearing engine is theoretically capable of using a highly granular network model, but it has never been used to do so. The uncertainty around the time and effort required to implement this new capability, both in the software and in the teams that support it, is such that it would likely not be ready by October 2022. The reverse is true for the other options: AEMO has substantial experience working with the hub-and-spoke model with a small number of regions, and believes either of the hub-and-spoke options are the most likely for delivery in the time available.

As the SWIS continues to evolve post-2022, with increasing connection of distributed generation and energy storage, more granular locational pricing signals are likely to become more useful and more important. If possible, the choice of market clearing model should not preclude future change to the granularity of pricing, while also providing information for market and network evolution.

Single region hub-and-spoke representation

In this model, network elements are not included directly in the clearing formulation. The network is represented by way of constraints on generator output, with each generator conceptually at the end of a spoke from the regional reference node (hence the term hub-and-spoke). Marginal loss factors are applied to the spokes to account for losses, while network constraints are modelled as a weighted linear combination of the output of generators and interconnector flows (where applicable). The weights assigned to generators reflect their contribution towards the constraint²⁹.

The constraint library may be manual or partially dynamic. Since network elements are not directly present in the clearing model, each network configuration³⁰ requires a separate set of constraint equations. In practice, it is not feasible to maintain constraints for every conceivable network state, meaning that a single constraint set will be used across a range of system conditions. Commissioning or retirement of network equipment requires redevelopment of the constraint library.

Multi-region hub-and-spoke representation

With multiple zones, some network elements are explicitly modelled. The power system is divided into regions or zones, with inter-regional transmission modelled explicitly, and intra-regional transmission modelled using the hub-and-spoke approach.

Thermal and security limits that create constraints between regions are modelled explicitly, so that the flow on a particular line or a group of lines cannot exceed limits determined by the system operator³¹. Inter-regional losses are modelled dynamically based on power flow and the specific characteristics of the network components, by using power flow equations that model real network behaviour.

Each region has its own regional reference node and constraint library that models the intra-regional network. Changing the region definitions requires redevelopment of the constraint library.

This model is used in the NEM, as shown in **Figure 8**.

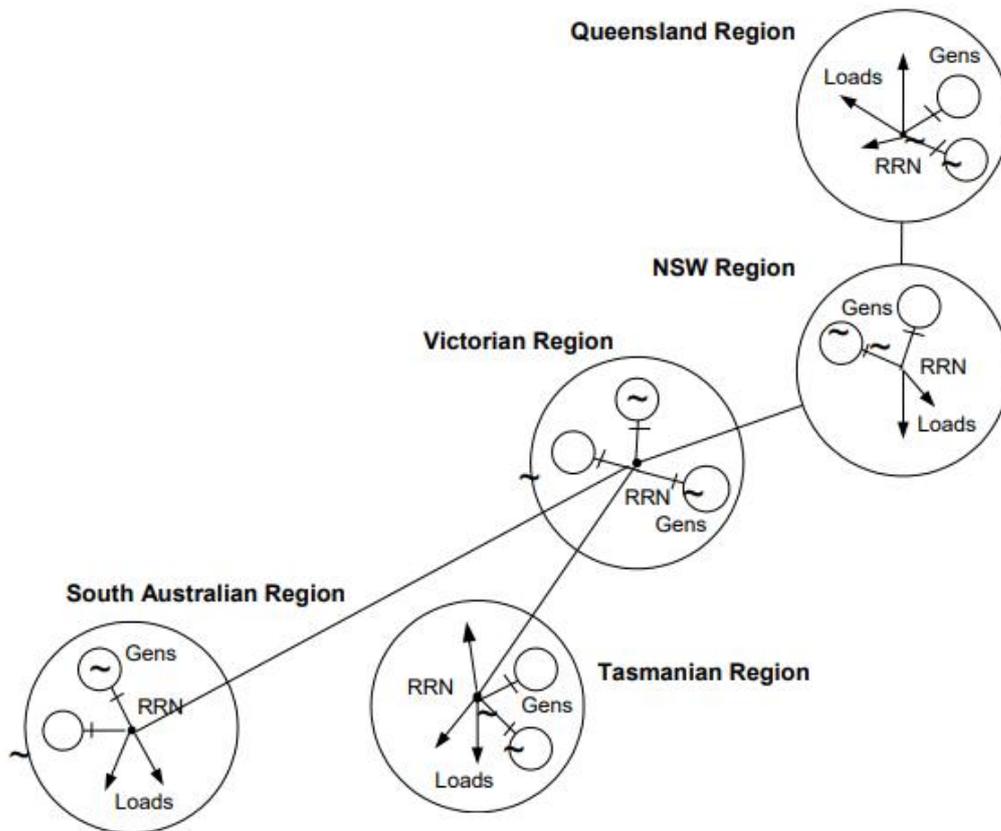
²⁹ For example, a constraint may take the following form: $w_1 Gen_1 + w_2 Gen_2 + w_3 Gen_3 \leq Constraint\ RHS$

Here, the transmission constraint is represented as function of the MW generation from generators Gen1 and Gen2 and the flow on a line interconnecting zones A and B. The weights w1 and w2 reflect the MW alleviation in the constraint above if Gen1 and Gen2 reduced their generation respectively by 1 MW. Hence, if the constraint were binding and Gen1 reduced its output by $w1\ MW$, then the constraint would be alleviated by 1 MW. Generators can be positively or negatively geared toward a constraint; hence an increase in a generator's output can also alleviate a constraint.

³⁰ Different network equipment status, load levels and power system conditions.

³¹ A transmission constraint may take the form: $Flow_{Line1} \leq Thermal\ Limit$ or $Flow_{Line1} + Flow_{Line2} + Flow_{Line3} \leq Security\ Limit$

Figure 8: Hub-and-spoke model of the NEM



Exploring a multi-region model of the SWIS

Principles for setting region boundaries

Definitions for a multi-region network representation should be informed by the physical characteristics of the network, and the location of current and projected network congestion. It is not crucial for regions to have the same electrical complexity or geographical size.

Where possible, region boundaries should be drawn so as to minimise the number of connections between regions. If there are too many connections between regions, the benefits of increased detail are diluted, as it becomes necessary to combine network components into a representative connection that aggregates their characteristics. In the NEM, most links modelled between regions consist of one or two of high voltage lines in relative proximity. The exception is between Victoria and New South Wales, where several widely geographically separated connections are modelled as a single interconnector³².

Region boundaries should also be placed to align with current and expected network constraints, so that congestion is visible between regions, giving granular information for the most relevant network components. The NEM regions align to state boundaries, and do not necessarily coincide with constraint locations. This reduces the usefulness of congestion

³² AEMO, 2017, *Interconnector Capabilities for the National Electricity Market*, accessible at: http://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Congestion-Information/2017/Interconnector-Capabilities.pdf

information from the inter-regional links, and if market pricing is regional, can distort market outcomes.

Over time, the location of load growth, generation commissioning and retirement, and network investment means that the reasons region boundaries were set can become invalid, leaving regions misaligned with physical characteristics of the power system. The market evolution framework for a multi-region clearing model would need to include a mechanism to identify potential need for change.

Placement of regional reference nodes

The single region clearing model would have a single regional reference node at Southern Terminal. In a multi-region model, each region would need a reference node (though pricing for the whole system would still be set based on the Southern Terminal price).

A regional reference node should be set such that:

- it is at a major load centre;
- energy flows towards it; and
- if intra-regional congestion is expected, it is between the regional reference node and generation (or other energy) sources.

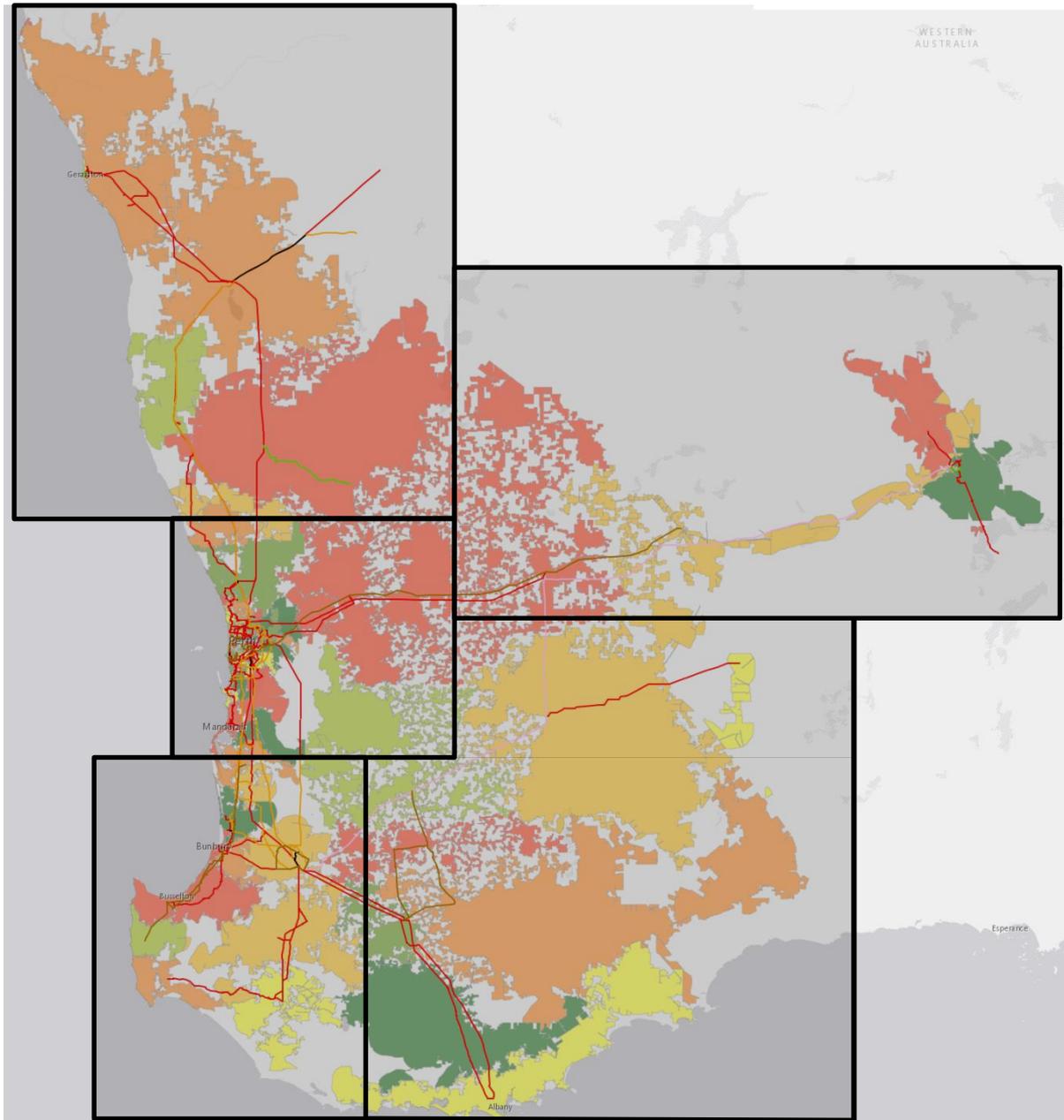
Possible regions for the SWIS

In order to allow assessment of the impact of constrained network access, Western Power and the Public Utilities Office prepared an initial set of constraint equations for a single SWIS-wide region, and identified potential for network congestion at Albany, North Country and East Country³³. Combining these congestion findings with the forecast network constraints identified in Western Power's most recent Annual Planning report³⁴ implies a minimal division into five regions: Perth, East, Southwest, Southeast and North, as indicated in **Figure 9**. These regions align with natural geographic and electrical boundaries in the grid, and with projected locations of network congestion. Given the large distances and location of congestion, East could be further separated into East Country and Goldfields.

³³ EY, 2018, *Modelling the impacts of constrained network access*, commissioned by Public Utilities Office, accessible at: https://www.treasury.wa.gov.au/uploadedFiles/Site-content/Public_Uilities_Office/Industry_reform/Modelling-the-impacts-of-constrained-network-access-EY-report.pdf

³⁴ Western Power, *2017 Annual Planning Report*, p. 87, accessible at: <https://westernpower.com.au/media/2360/annual-planning-report-2017.pdf>

Figure 9: Possible SWIS regions³⁵



However, this division is not without problems. It is not possible to draw a boundary between Perth and Southwest without crossing at least seven transmission lines. Boundaries between regions are crossed by at least three transmission lines, some terminating at very different points within the region. This increases the difficulty of modelling inter-regional network equipment, and reduces the quality of the information between what would be the two largest regions electrically.

³⁵ Based on Western Power's network capacity mapping tool. Accessible at: <https://westernpower.com.au/industry/calculators-tools/network-capacity-mapping-tool/>

The reference node would usually be set at a major load centre. However, in some of these regions energy generally flows away from the largest load centre. It may therefore be necessary to select a different location for the regional reference node. For example, the reference node for the North Country may be more appropriately placed at Three Springs, a location away from direct generator connections, and with potential to be affected by network constraints to the north and south.

Future state

From a dispatch standpoint, a multi-region representation would provide incremental benefits over the single-region clearing model.

1. More accurate modelling of network constraints allows more efficient dispatch, and less manual intervention.
2. Where the clearing engine calculates line flows based on the specific conditions on the power system at the time, real-time market dispatch is based on actual network losses between regions rather than static loss factors, increasing accuracy and reducing settlement residues arising from annual loss factors.
3. More specific information to support generation and network investment decisions. Outputs clearly quantify the impact of network congestion on market outcomes, tied directly to specific network elements.

However, it would come with higher implementation complexity.

1. Region and reference node definition is difficult and uncertain, as discussed above.
2. Western Power has already put significant effort into the development of constraint equations representing thermal limits in a single region model. A regional model would require redevelopment of specific constraints for each region.
3. Upcoming changes to the RCM were assessed on the basis of a single region constraint set, and work on a capacity allocation mechanism has continued this assumption. Using a multi-region model would not invalidate past analysis, but would require more complexity in the allocation methodology.
4. A multi-region model would require more complex data structures, interfaces and data manipulation for settlement.

Both models provide improved information to support network planning in the form of constraint results, the extent to which network and security constraints are binding, and the effect of network congestion on market outcomes can be inferred from MCE outputs.

A multi-region clearing model would support a transition to regional pricing without amendment of the underlying clearing engine model, but transition to locational pricing across the full high-voltage network (as is used in all other gross pool markets) would require a complete reimplementing of either clearing algorithms. Further, they can both provide data to support analysis on the future introduction of more granular pricing, through the 'pseudo-nodal' prices generated by the MCE. Because the NEMDE engine can support both single-region and

multi-region clearing, and can likely support nodal clearing as well, possible future market evolution is not blocked by choice of clearing engine or clearing model.

Design approach

The approach is to:

- use a single-region hub-and-spoke network model in the clearing engine; and
- schedule a review of the need for future market evolution to more granular clearing and pricing, using MCE outputs to assess the level of distortion created by a single, system-wide price.

Contribution to market objectives

	Objective	Contribution
1.2.1(a)	Promote economically efficient, safe and reliable production and supply of electricity in the SWIS	A single-region hub-and-spoke clearing model reduces the risk of delay in delivery of overall benefits from the market improvements, across all categories
1.2.1(b)	Encourage competition, including facilitating efficient entry of new competitors	
1.2.1(c)	Avoid discrimination against particular energy options and technologies, including sustainable energy options	
1.2.1(d)	Minimise the long-term cost of electricity supplied to SWIS customers	
1.2.1(e)	Encourage measures to manage the amount of electricity used and when it is used	

3.2.2 Ramping

'Ramping' of a facility is changing from one output level to another. The 'ramp rate' is the rate of change in instantaneous output, and the 'ramping profile' is the shape of the time series between two points in time.

Current approach

Currently, dispatch instructions (for facilities not in the Synergy portfolio) are issued ten minutes before the start of the 30-minute dispatch interval, and again five and 15 minutes after the start of the interval. Each dispatch instruction specifies a target to be reached and a ramp rate to use while ramping. When responding to a dispatch instruction that changes the quantity of output required, facilities are required to ramp at the specified rate. This requirement is built into dispatch compliance monitoring and out-of-merit calculations. The ramp rate used in dispatch instructions is always the ramp rate submitted in offers (unless overridden by the controller), which represents the maximum possible ramp rate achievable by the facility. This

approach ensures that, where a facility is dispatched, it will reach its target output in the shortest possible time. As a result, most generator ramping occurs in the first few minutes after a dispatch instruction.

The resulting ramp profile does not match the load profile, which generally changes more smoothly. Where the maximum ramp rate is faster than necessary for balancing supply and demand, there will be an excess or shortfall of energy within the interval (depending on whether the generator is ramping up or down). The resulting imbalance in supply caused by intra-interval deviation between generation ramp profile and load ramp profile is covered by the use of the load following ancillary service³⁶.

Future state

The introduction of a five-minute dispatch interval will allow generation dispatch movements to be more closely matched to load changes, with smaller changes in dispatch from interval to interval, but the underlying issue will still remain.

New facilities (particularly battery storage) are likely to have higher ramp rates than existing facilities, adding to the size of the issue.

Some markets (including the NEM) require facilities to ramp at a linear rate ('linear ramping') between the facility's current output and its new target. This provides a better match between the intra-interval movement of supply and demand, and reduces this component of the load following requirement as far as possible.

This approach could be implemented in the WEM either by AEMO specifying a ramp rate in the dispatch instruction that is lower than the facility's maximum ramp capability, or by removing the ramp rate from the dispatch instruction entirely, and specifying the requirement to ramp linearly in the rules.

A comparison of the linear and maximum ramp profiles for a period of real load at the beginning of the afternoon ramp on 18 October 2018 is shown in **Figure 10**, with an assumed system-wide ramp rate of 50 MW per minute.

³⁶ This forms only part of the load following service requirement, which must also cover differences between forecast and actual load and intermittent generation, and dispatch non-compliance.

Figure 10: Ramp Rate Comparisons, beginning of evening ramp on 18/10/2018

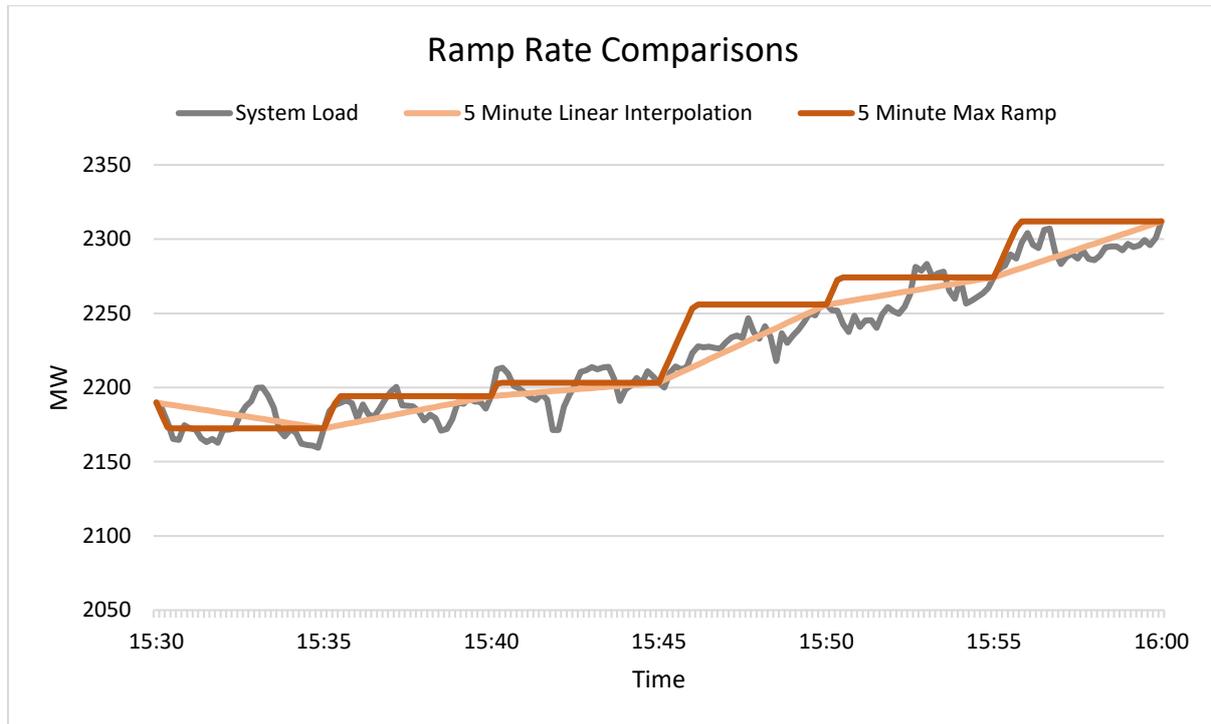
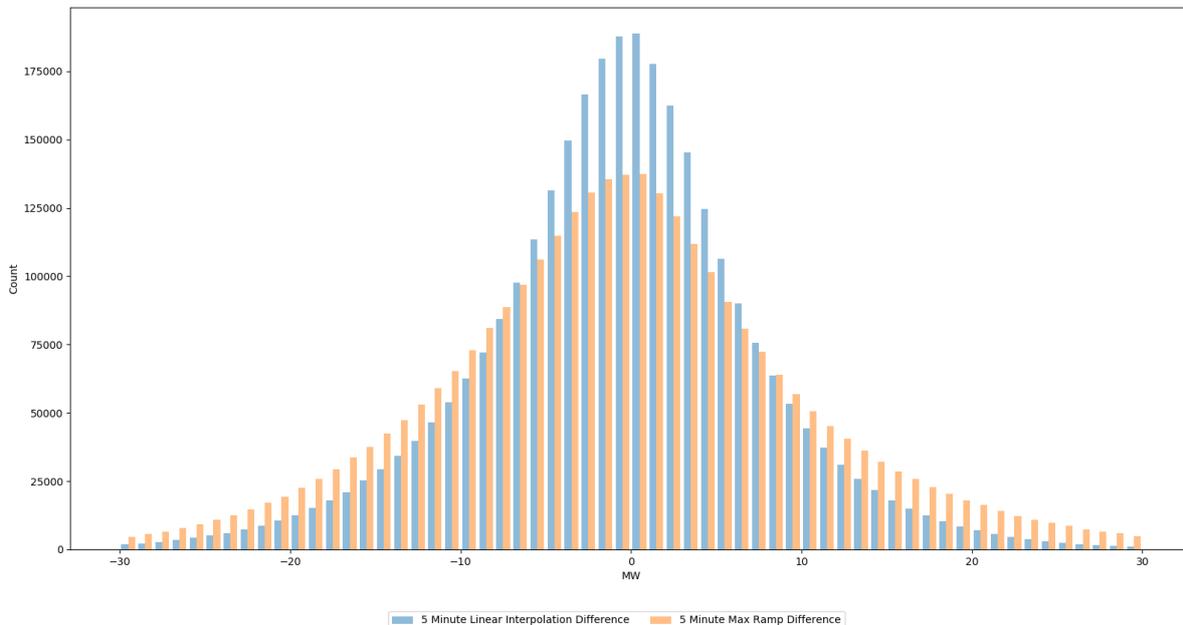


Figure 11 shows the distributions of the differences between the two possible ramp profiles and the actual load for each ten-second interval from January to December 2018.

Figure 11: Differences between actual load and ramping profiles – CY 2018



The match between supply and demand is significantly improved with linear ramping. With a maximum ramp requirement, 99.8 per cent of the time the deviation is between -39 MW and +40 MW. With a linear ramp requirement, 99.8 per cent of the time the deviation is between -35 MW and +31 MW.

All other things being equal, dispatch using the maximum ramp profile for ramp rates will require a greater quantity of load following to balance total generation than a linear ramp. A larger load following requirement will increase total costs to market, so adopting a linear ramping requirement could contribute to overall lower costs in the reformed WEM. However, ramp profiles are not the only contributor to load following requirements, nor the largest. The variability in load forecast and intermittent generation output is greater than the possible 5 to 10 MW contribution from changing the required ramp profile, and it is not clear how many intervals this saving would actually manifest in a reduction in the overall essential system service requirement.

The ability to implement a linear ramping profile, outside AEMO's automatic generation control (AGC), is dependent on the capability of facility control systems, which may require changes or upgrades to implement new ramping profiles. If this cost is significant, it may cancel out benefits from the reduction in load following requirement. Further information is being sought from participants on the capability of their control systems to implement a linear profile.

Design approach

Where facilities are dispatched via AGC, AEMO should use a linear ramping profile.

Contribution to market objectives

	Objective	Contribution
1.2.1(a)	Promote economically efficient, safe and reliable production and supply of electricity in the SWIS	Reduces volatility in generation output from controllable factors
1.2.1(d)	Minimise the long-term cost of electricity supplied to SWIS customers	Reduces the quantity of ancillary services required, reducing overall costs of supply

3.2.3 Intermittent generator forecasting

Current approach

Intermittent generators currently offer into the BMO with a single price-quantity pair. The offered quantity is meant to represent a participant's best estimate of forecast output (from which the facility can be dispatched down), but the level of accuracy varies.

When the market is cleared in the Balancing Forecast, intermittent generator offer quantities may, at AEMO's discretion, be replaced by AEMO's own forecast. For dispatch timeframes, AEMO uses a persistence forecast, where forecast quantities are replaced by current output measurements.

Future state

Current market rules require a market participant to ensure offers into the real-time market accurately reflect its 'reasonable expectation of the capability of its Balancing Facilities to be

dispatched³⁷. For intermittent facilities this means that participant offers should reflect their generation forecast. This treatment aligns with the principle that intermittent facility operators are the ones best placed to forecast the potential output of their own facilities.

Inaccurate forecasts have an impact on the quantity of load following service required – lower accuracy requires greater load following service to compensate. In the current market, the most recent participant forecast is made some time in advance of real time, so AEMO replaces the participant forecast with a persistence forecast³⁸ in dispatch calculations.

If participant forecasts can be made closer to real time (as they will be with the introduction of five-minute dispatch intervals and shortened gate closure), they can be more accurate, but there is still potential for poor forecasting by participants³⁹. To preserve system security and ensure accuracy of dispatch, it is important that AEMO be able to replace inaccurate forecasts in dispatch calculations, and it is proposed that this discretion be retained.

Replacement of forecasts in the pre-dispatch schedule is a related issue. If AEMO were to adjust pre-dispatch schedule inputs to replace forecasts it believed to be inaccurate, it could provide better information to participants, but would also detract from the principle that participants are best placed to provide accurate information into market processes.

Design approach

The approach is to:

- retain the obligation on intermittent generators to submit market offers representing their forecast output;
- retain the power for AEMO to replace intermittent generation offer quantities with AEMO forecast, with any increase added to the highest priced offer tranche, and any decrease subtracted from tranches in order of highest to lowest priced and
- provide financial incentive for intermittent generators to provide accurate forecasts, whether through essential system service cost recovery or another mechanism.

³⁷ WEM Rules 7A.2.8(b)

³⁸ A persistence forecast assumes that the current level of production will continue, which is usually accurate over very short timeframes.

³⁹ In the current market, there are limited consequences for participants who provide an inaccurate forecast, as intermittent facilities only face LFAS costs in proportion to their total injection, not their forecast accuracy. While ancillary service cost recovery will be dealt with in a later design paper, initial thinking is that this position will change to reflect a 'causer pays' approach to cost recovery, giving participants better incentive to forecast accurately.

Contribution to market objectives

	Objective	Contribution
1.2.1(a)	Promote economically efficient, safe and reliable production and supply of electricity in the SWIS	Forecasting responsibility sits with the entity with the greatest ability to influence accuracy, increasing system efficiency and reliability

3.2.4 Optimisation of energy storage utilisation in the real-time energy market

Energy storage facilities hold energy produced at one point in time for use at a later time. While storage technologies use a variety of mechanisms, all can charge, hold and discharge energy within certain parameters. Technologies include:

- battery systems (electrochemical storage);
- pumped hydro (mechanical storage)⁴⁰;
- molten salt (thermal storage)⁴¹; and
- hydrogen (chemical storage).

Battery storage is the only type of energy storage system currently connected to the SWIS. Clean Energy Regulator data records just under 700 small-scale solar-plus-battery systems installed in Western Australia⁴² as at the end of 2018. The Smart Energy Council estimates that this represents between a third and a half of all installations.⁴³ Synergy and Western Power have installed larger systems on a trial basis, including the largest to date, the 1.1 MW Alkimos Beach community battery. Further grid-scale systems are planned or under construction at Garden Island, Kalbarri and Perenjori.

Current approach

There are no energy storage facilities currently participating in the WEM. As a part of initial work under this project, prior to the establishment of the Taskforce, the Public Utilities Office and AEMO assessed the feasibility and value of interim participation under current market arrangements, where there is no storage specific generation class⁴⁴. There is no mechanism

⁴⁰ Traditional hydro-electric generation is excluded from the definition, as it does not draw electrical energy in order to charge its storage reservoir.

⁴¹ A household hot water cylinder is excluded from the definition, as it does not inject electrical energy back into the grid. It can provide flexibility from reducing load rather than increasing supply.

⁴² Australian Government, Clean Energy Regulator, *Postcode data for small-scale installations*, accessible at: <http://www.cleanenergyregulator.gov.au/RET/Forms-and-resources/Postcode-data-for-small-scale-installations>

⁴³ [Australian Energy Storage Market analysis, Sep 2018](#)

⁴⁴ A paper on interim pathway for storage facilities to register and participate in the WEM under the current rules framework was published in June 2019. Available at: <https://www.erawa.com.au/rule-change-panel-mdowg>

in the current WEM to schedule and dispatch consumption (or a negative injection quantity) in the real-time market.

The current 30-minute dispatch interval and two-hour gate closure pose barriers to unlocking the full flexibility of energy storage systems.

Future state

Grid-connected and distributed energy storage systems will be a crucial part of managing increasing volume of intermittent generation and the changing profile of demand from the system. Experience elsewhere has shown that essential system service provision is likely to be the first commercial use case for battery participation in wholesale markets, but as costs decrease, greater installed storage capacity will allow the time-shifting of energy on a larger scale. The reformed WEM must have mechanisms to allow storage technologies to participate in the wholesale markets for both energy and essential system services.

The move to a five-minute dispatch interval, coupled with significant reduction in gate closure, supports the flexible operation of storage facilities in the energy market, allowing them to offer their full discharge capability over a shorter interval, and to re-offer for future intervals based on how dispatch affects the amount of energy stored. There is a mirror opportunity for optimising the charging portion of the cycle, but whether this can be accessed depends on the design of the market clearing engine.

There are three main methods by which energy provision by storage facilities could be incorporated into the reformed WEM's real-time energy market.

1. Facilities offer for injection only. Withdrawal is self-scheduled, and at the discretion of the facility owner. Injection is dispatched by the market and is subject to dispatch compliance monitoring and penalties. This would align with what is possible in the existing WEM. It could cause inaccuracies in load forecasting, and would preclude storage provision of essential system services while the facility was charging.
2. Facilities offer for injection and bid for withdrawal. Both injection and withdrawal are dispatched by the market, and subject to dispatch compliance monitoring and penalties.
3. In addition to offers and bids, the market clearing engine has visibility of facility capability, charge state and any constraints around state changes from charging to discharging or vice versa. Decisions on when to charge and discharge are optimised by the market clearing engine.

Options 1 and 2 leave market positioning and decisions about optimal charge and discharge times to the facility owner, and dispatch decisions are made for one interval at a time. Under option 2, participants would be required to ensure that the withdrawal bid price is always lower than the injection offer price.

Option 3 would place charge-discharge scheduling decisions in the hands of the market operator, as well as introducing an intertemporal component, requiring market schedules to optimise across time. This approach to storage scheduling is used in some jurisdictions where there is a binding day-ahead market and centralised commitment.

The reformed WEM will not be adopting centralised commitment, so Option 2 aligns most closely with the treatment of scheduled generation facilities.

Regardless of whether charge state is used in scheduling energy, essential system service dispatch will require AEMO visibility of charge state. AEMO will also need visibility of charge state for non-essential system service storage facilities to support system emergency operation.

Design approach

The approach is as follows.

- Storage facilities submit offers covering injection and withdrawal, both operations are dispatched through market processes, and both operations are subject to dispatch compliance monitoring and enforcement. The MCE optimises over a single dispatch interval, and participants are responsible for considering timing of charge and discharge in constructing their offers.
- Storage facilities provide capacity information as part of standing data, and charge state information as a real-time data feed.

Registration and participation requirements for storage facilities will be considered in a later design paper. Preliminary work suggests that:

- storage facilities will be registered in a new facility class;
- other facility classes will be amended to explicitly reference the potential for co-located storage installations; and
- an intermittent generator co-located with a storage facility may, if aggregated, meet the criteria for registration as a scheduled generator.

Contribution to market objectives

	Objective	Contribution
1.2.1(a)	Promote economically efficient, safe and reliable production and supply of electricity in the SWIS	Dispatching storage charging along with other controllable facilities increases predictability of system load
1.2.1(c)	Avoid discrimination against particular energy options and technologies, including sustainable energy options	Making participants responsible for inter-temporal constraints aligns with treatment of scheduled generation commitment decisions
1.2.1(d)	Minimise the long-term cost of electricity supplied to SWIS customers	Facilitation of storage enables cheaper generation to be time-shifted to displace more expensive generation, lowering the overall cost of supply
1.2.1(e)	Encourage measures to manage the amount of electricity used and when it is used	

3.2.5 Market schedules

Pre-dispatch schedules signal forecast market outcomes at regular intervals ahead of real time, allowing participants to see what is projected to happen, adjust their offers, and react to changes made by other participants.

Current approach

The current unconstrained market design means information for participants is published via multiple channels, and market schedules are not generated by the same processes used to determine final dispatch.

Much of the information used by AEMO to determine final dispatch is published, but it is piecemeal and difficult for participants to integrate.

- Energy scheduling information is provided to the market by way of forecast BMOs published by AEMO. The forecast BMO includes expected system load, expected Balancing Price, and the expected dispatch of the receiving participant, on an unconstrained basis. AEMO also publishes LFAS forecasts, containing similar information for the LFAS market.
- Information on potential future network and security constraints is published weekly in the Short-Term (ST) PASA, but this information does not provide specific advice on how they will affect individual facilities. Where a specific impact can be foreseen, AEMO publishes dispatch advisory notices to market participants, but this is not always possible.
- Several times daily, AEMO prepares a dispatch plan to account for Synergy portfolio dispatch, ancillary service requirements, and network and security constraints, and provides expected energy, ancillary service and fuel quantities to Synergy. This plan is not published to the market. This means that participants (other than Synergy) do not have access to the market operator's best estimate of what will actually happen in future trading intervals. While Synergy has better information about expected future dispatch for its facilities than other market participants do for theirs, AEMO control of dispatch and advanced gate closure means Synergy has limited opportunity to use it, other than for preparing fuel nominations to ensure its plant can meet the schedule.

The relation between participant offer changes and market outcomes is opaque, increasing participant uncertainty over what will actually happen in real time. There are several sources of uncertainty for participants using current market forecasts.

1. Forecast BMOs do not include impacts of any network or security constraints.
2. Forecasts do not account for projected facility testing, which can introduce additional variability in a similar manner to intermittent generation.
3. Forecasts for load and intermittent generation can change significantly between offer and dispatch.
4. Forecasts are based on AEMO's automatic load forecast, which may be manually overridden in the control room (for the short-term dispatch horizon) without feeding into market processes.

5. If a participant suffers an outage but has not re-offered, the outage is not reflected in market schedules.
6. Forecasts are not price transparent to participants (i.e. participants can only see their own offer prices in relation to all others in aggregate).

Future state

The introduction of security-constrained dispatch will allow a more sophisticated approach to market schedule publication.

- Offers, network and security constraints will all be incorporated into the clearing engine, which will allow an integrated pre-dispatch schedule reflecting AEMO's best information, and more accurately predicting future dispatch.
- Shorter gate closure times will allow participants opportunity to respond to changes in market conditions closer to real time.
- AEMO manual overrides will flow into market scheduling processes, ensuring that market schedules reflect the best information available.

Pre-dispatch schedules generated by the same process as dispatch decisions will provide more actionable information to participants, but there are still a number of parameters that must be determined, including

- horizon, resolution and frequency;
- schedule content; and
- sensitivity information.

Horizon, resolution and frequency

Forecast schedules project forward a certain distance in time, at a certain time granularity, and are published on a defined schedule. Ideally, participants will have information to support decisions on commitment, fuel purchase, short-term contracting and short-term outage planning, all of which require a lead time of hours to days.

Schedules are only as accurate as their inputs. The uncertainty in load and intermittent generation forecasts is such that projections more than a few days out can be indicative only, and high time resolution for long forecasts provides only spurious accuracy.

The current WEM forecast BMO horizon and frequency is similar to that used in many markets, forecasting expected outcomes over the next 14-38 hours, with a resolution matching the current dispatch interval of 30 minutes. The introduction of a five-minute resolution for dispatch (and potentially settlement) does not mean that forecast schedules must use the same resolution.

Drawing on experience in other markets, alternative or additional potential forecast horizons to consider include the following.

- A very-short-term forecast of the next few dispatch intervals, potentially with greater time resolution (i.e. five minutes). The NEM produces a forecast of the next 12 five-minute dispatch intervals.
- A week-ahead forecast, published daily. This forecast schedule is used in both New Zealand and Singapore.

Table 4: Market forecast schedules in Australia, New Zealand and Singapore

Market	Schedule	Horizon	Resolution	Publication
WEM	Forecast BMO	14 to 38 hours To end (0800) of D0	30 minutes	Every 30 minutes
NEM ⁴⁵	Pre-dispatch	12 to 36 hours To end (0400) of D0	30 minutes	Every 30 minutes
	5-minute pre-dispatch	60 minutes	5 minutes	Every 5 minutes
NZ ⁴⁶	PRSS/NRSS ⁴⁷	4 hours	30 minutes	Every 30 minutes
	PRSL/NRSL ⁴⁸	36 hours	30 minutes	Every 2 hours
	Weekly Dispatch Schedule	6 days D0 to D+5	30 minutes	Daily
Singapore ⁴⁹	Short term schedule	6 hours	30 minutes	Every 30 minutes
	Pre-dispatch schedule	12 to 36 hours To end of D0	30 minutes	Every 2 hours
	Market Outlook Scenario	6 days D0 to D+5	30 minutes	Daily

⁴⁵ <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Data/Market-Management-System-MMS/Pre-dispatch>

⁴⁶ Transpower, 2018, *SPD Schedule Inputs*, Accessible at:
<https://www.transpower.co.nz/sites/default/files/bulk-upload/documents/GL-OC-209%20SPD%20Schedule%20Inputs.pdf>

⁴⁷ Price Responsive Schedule Short and Non-Responsive Schedule Short

⁴⁸ Price Responsive Schedule Long and Non-Responsive Schedule Long

⁴⁹ Singapore Electricity Market Rules, *Appendix A - Market Operations Timetable*, Accessible at:
https://www.emcsg.com/f283,7867/Appendix_6A_Market_Operations_Timetable_1Jan19.pdf

Schedule outputs

To be most useful for participants and maximise transparency, schedule outputs should provide as much information as possible, while still respecting participant commercial sensitivity.

Sensitivity information

Forecast schedules will necessarily present AEMO's best estimate of future dispatch outcomes. They can also provide information about the level of uncertainty, or outcomes under different input assumptions. Doing so can contribute to market efficiency by giving additional context to the likelihood of particular market prices, allowing participants to have more confidence in decision making.

While the incremental cost of calculating and publishing a small number of sensitivity schedules is very low, the practice is unusual and most electricity markets do not publish sensitivity information. The exceptions are the NEM, Singapore and New Zealand.

- The NEM publishes price and interconnector flow forecasts (but not dispatch forecasts) for around 40 alternate load forecast scenarios⁵⁰, along with the day-ahead pre-dispatch schedule.
- Singapore publishes full price and dispatch forecasts for three load forecasts: low, normal and high⁵¹. Currently these are published with both the week-ahead and day-ahead schedules.
- New Zealand publishes 'price responsive' and 'non-responsive' schedules, respectively with and without expected demand response.

The WEM is smaller and less complex than the NEM, and the use of a single system-wide price reduces the need for multiple scenarios covering load in each pricing region.

Design approach

Error! Reference source not found.5 shows the set of schedules that will provide pre-dispatch forecast information to market participants in the reformed WEM. All schedules would be run with constraints representing the expected network configuration in each time period.

Table 5: Proposed WEM forecast schedules

Schedule	Horizon	Resolution	Frequency	Rationale
Dispatch schedule	2 hours	5 minutes	Every 5 minutes	Very short-term schedule at dispatch interval resolution. First interval of horizon is the actual dispatch

⁵⁰ AEMO, 2014, *Pre-dispatch sensitivities*. Accessible at: http://aemo.com.au/-/media/Files/PDF/Pre_Dispatch_Sensitivities_6_1_March_2014.pdf

⁵¹ Energy Market Company, 2018, Notice of Market Rules Modification, EMC/RCP/103/2018/352. Accessible at: <https://www.emcsg.com/f1745,132695/EMC352-EMA-LL.pdf>

Schedule	Horizon	Resolution	Frequency	Rationale
Pre-dispatch schedule	48 hours	30 minutes	Every 30 minutes	Supports commitment, fuel and STEM timelines
Week ahead schedule	6 days (from end of Dispatch Schedule)	30 minutes	Daily, early hours of morning	Indicative information to end of feasible load forecast horizon Fills the role played by the ST PASA in the current WEM

Schedules with 30-minute resolution would use offers from the last five-minute dispatch interval in the half hour. It may be possible to use five-minute resolution for the pre-dispatch schedule, but that will only become clear during implementation.

To support forecast schedule production, participants would be required to have standing offers in place for at least the next seven days. The week-ahead schedule would use AEMO's central forecast of intermittent generation.

Schedules would include, for each interval, the forecast of:

- load;
- intermittent generation;
- energy prices;
- essential system service prices;
- constraints binding and close to binding; and
- dispatch for each facility.

Participant offer data would be published on day D+1.

Sensitivity schedules would be published alongside pre-dispatch and week-ahead schedules. Specific sensitivities will be investigated further by AEMO and should be covered in a market procedure. Initial thinking is for sensitivities covering:

- 10 per cent POE load forecast, 90 per cent POE intermittent generation forecast;
- 90 per cent POE load forecast, 10 per cent POE intermittent generation forecast;
- 50 per cent POE load forecast with a range of critical possible network outages; and
- 50 per cent POE load forecast excluding non-synchronised facilities (capacity designated 'available' by its owner rather than 'In-service' as in section 3.1.5).

0 shows possible market timelines with these schedules.

Contribution to market objectives

	Objective	Contribution
1.2.1(a)	Promote economically efficient, safe and reliable production and supply of electricity in the SWIS	Better information allows participants to better respond to market conditions, increasing efficiency, providing better basis for competition, and reducing overall cost to supply
1.2.1(b)	Encourage competition, including facilitating efficient entry of new competitors	
1.2.1(d)	Minimise the long-term cost of electricity supplied to SWIS customers	
1.2.1(e)	Encourage measures to manage the amount of electricity used and when it is used	Better information on the range of future market outcomes will allow better self-management by large consumers to reduce load in periods of high price

4. Short-term energy market

The STEM has operated alongside the RCM since 2006. As a binding day-ahead market, STEM provides a centrally coordinated opportunity for participants to trade around their bilateral contract positions, supplementing and complementing the off-market bilateral contracts regime. It also provides a firm financial basis for commitment of long-start-time facilities on the following trading day. In 2017-18 approximately 4 per cent of total WEM energy transaction value was traded through the STEM.⁵²

This chapter discusses issues arising from impacts on the STEM of the move to a SCED real-time market.

4.1 Interaction between STEM and real-time markets

Current approach

The current STEM is a day-ahead market, where participants bid and offer around their declared net contract positions for each 30 minute interval. It is a simple market, designed for financial trading, rather than centralised scheduling and commitment.

- It operates at participant level, not facility level. Each participant notifies their bilateral contract position to the market operator, and submits offers and bids to trade around that position. Because it is centred on participant contract volumes, there is no need for facility-level information.
- It does not directly consider future power system conditions. The STEM auction matches supply offers with demand bids, rather than matching supply offers to a load forecast.
- It does not consider network or security constraints. The STEM auction clears on an unconstrained basis. Known future network constraints affecting generation are reflected in STEM through participant outage lodgements.

STEM offers are limited to the Maximum Supply Capability (MSC) for each facility calculated by AEMO. This means that participants cannot trade in the STEM unless backed by firm generation or bilateral contracts. The MSC takes the standing data facility capacity and adjusts for:

- outages;
- losses between the facility location and the reference node; and
- expected essential system service enablement.

Participants must ensure that STEM submissions for their facilities comply with the following requirements.

- They total less than or equal to the MSC. Submissions in excess of the MSC are automatically removed.

⁵² Bilateral contracts: 87%, STEM: 4%, Balancing: 9%.

- They are sufficient to cover their Reserve Capacity Obligations, i.e. that all capacity with active capacity credits is made available to the market, either through bilateral contracts or in STEM offers.

While STEM outcomes do not directly affect real-time market inputs or outputs, they do have financial impacts, both through direct energy trading, and potential for reserve capacity refunds based on mandatory offer requirements. As a result, most participants offer more volume into the STEM than their capacity credits. This includes owners of intermittent generation facilities, who are not currently required to offer that capacity into STEM, as their Reserve Capacity Obligation Quantity (RCOQ) is zero.

Both STEM and the Balancing Market operate on a net settlement basis. Settlement quantities take bilateral contract quantities into account, so that the amounts paid by and to market participants are net of their contract positions.

Future state

Data provided by AEMO

The introduction of co-optimised SCED clearing into the real-time energy and essential system service markets means the pre-dispatch schedule will incorporate AEMO's best estimate of forecast dispatch, including essential system service enablement and network outages. The projected essential system service volumes could be incorporated into the calculation of the MSC and reserve capacity refund calculations, but are likely to be much more volatile than they are at present, and anticipated changes to outage processes (to remove the lodgement of consequential outages) mean the mechanism for identifying network outages affecting a facility will not be available. The remainder of the data provided by AEMO to support STEM submissions can still be obtained by the same processes as it is today.

Interaction between constrained real-time dispatch and minimum offer requirement

Participants are already subject to a risk of network constraints arising between day-ahead and real time, resulting in a difference between their STEM position and their real-time generation. As the incidence of constraints increases over time, real-time market dispatch may at times diverge significantly from what would have occurred in an unconstrained model.

In the real-time market, there is no risk to participants from being required to offer their full capacity, as the clearing engine accounts for network constraints in calculating dispatch. With an unconstrained STEM and a security-constrained dispatch, generation participants affected by increasing network and security constraints may find it harder to offer into STEM in such a way that their generation is matched to their contract position. Further, if a participant is cleared for less injection than they would have been under an unconstrained dispatch, and must purchase from the pool to satisfy contractual obligations, they will not be entitled to constrained off payments to offset their pool purchases. Existing bilateral contracts are subject to the same dynamic.

As discussed in section 3.1.5, the requirement to offer into short-term markets is the key mechanism by which RCM outcomes are translated into availability, and ensure that the day-ahead market is liquid with volumes available at a reasonable cost. There is no change in the underlying characteristics of the market that would merit a change to this requirement,

but there is a question of whether and how minimum STEM offer quantities should be adjusted for network constraints.

Participants can have some confidence that their capacity credit volumes will be dispatchable in real time. Capacity credits are allocated based on peak demand, and the allocation process will take account of network capability. This means that participant capacity credits will reflect a combination of injections that is physically feasible at the time of system peak demand, the time with greatest likelihood of network constraints. Nevertheless, some uncertainty will remain.

There are three options to account for the effects of constraints in STEM minimum offer requirements.

1. Centralised calculation of projected injection capability for each facility.

It would be theoretically possible to use the SCED clearing engine to calculate a 'maximum possible injection' for each facility. Such a calculation would be computationally intensive, and would require running a dedicated pre-dispatch schedule for each facility, with the facility's offer price reduced to the market floor to ensure it is dispatched for the maximum possible quantity.

2. Restricting minimum offer volumes to the energy volumes from the pre-dispatch schedule.

The pre-dispatch schedule will show forecast energy dispatch including the effects of network and security constraints. However, energy volumes are also dependent on the load forecast (which will almost always be significantly lower than the total volume of capacity credits issued) and prices offered by participants. Using these volumes alone to set minimum offer requirements would almost completely de-link the requirement to offer into STEM from RCM outcomes.

3. Retaining the obligation to offer all capacity credit volumes into the STEM, with flexibility in pricing.

The pre-dispatch schedule provides the best estimate of future dispatch outcomes, including incorporation of network outages. This volume can be reasonably expected to be cleared at real time, and should be offered into the STEM with the current short-run marginal cost (SRMC) obligations. The remainder of capacity credit volume would still be offered, but participants would have flexibility to set prices for the remainder based on their own assessment of risk. The pre-dispatch schedule and its sensitivities will provide information to participants on whether their facilities are likely to be dispatched, for what quantity, and at what price the real-time market is likely to clear. This is more information, of better quality, than available to participants in the current market, and provides a basis on which to structure STEM offers to reflect the remaining uncertainty.

The use of pre-dispatch schedule data for STEM offer construction does provide a gaming opportunity for participants, who could engineer their essential system service offers so as to reduce their energy offer requirement into the STEM, then change them to get a higher energy dispatch in the real-time market. This behaviour would be detectable through ex-post market monitoring.

Settlement interval

At present, the STEM interval matches both the dispatch interval and the settlement interval. This means that bilateral contract quantities and STEM results have the same time resolution as settlement calculations, including balancing amounts and reserve capacity refund calculations.

There is no requirement to match the STEM interval to reflect the shorter dispatch interval, as there is no direct link between STEM outputs and real-time dispatch. However, if the settlement interval changes to five minutes, the link to STEM time resolution must be handled in one of two ways.

- Change the STEM interval and the bilateral contract submission resolution to match the settlement interval, increasing the number of STEM intervals to 288 per day.
- Retain a 30-minute STEM interval, and divide STEM outputs across the six settlement intervals within each STEM interval.

Netting 30-minute STEM outputs out of five-minute energy settlement would be relatively simple. Marrying a 30-minute STEM interval with five-minute capacity refund calculations would be more complicated, but still possible.

Implementing a five-minute STEM would provide flexibility for participants to smooth their contract position, while not precluding the use of the same offers for each five minute interval.

Efficient market outcomes

STEM liquidity is affected by both the quantities available and the prices at which participants offer. The RCM-linked obligation to offer capacity has a secondary benefit of ensuring that there is as much energy available as possible. The obligation to ensure offer prices do not exceed SRMC is the major mechanism by which the exercise of market power is restricted. This aspect of market power mitigation will be revisited in a later design paper.

Design approach

The approach is to:

- replace AEMO calculation of MSC with the obligation to provide pre-dispatch schedule outputs;
- retain the obligation for participants to offer volumes based on capacity credit holdings, but remove adjustment for projected essential system service quantities and network outages;
- relax the requirement to offer at SRMC to only apply to pre-dispatch energy volumes; and
- align the STEM interval with the settlement interval (whichever is chosen).

Contribution to market objectives

	Objective	Contribution
1.2.1(b)	Encourage competition, including facilitating efficient entry of new competitors	Aligning STEM interval with settlement interval and requiring capacity to be made available allows participants to align contract position with market risk

4.2 STEM timing*Current approach*

The current STEM process is structured around AEMO publishing STEM auction results by 11.30am. This timing was originally driven by a multi-step process. Participants needed access to STEM results in time to prepare and submit resource plans. Then System Management needed time to prepare the Synergy dispatch plan based on participant resource plans, and finally Synergy needed time to make fuel nominations based on the Synergy dispatch plan.

Resource plans were removed with rule change RC_2014_06 on 1 July 2019. System Management now prepares the Synergy dispatch plan based on the forecast BMO, and the timing for STEM submissions and publication of STEM auction results was moved by one hour.

Future state

With the introduction of facility bidding for Synergy, the requirement to prepare a separate Synergy dispatch plan will be removed, and both AEMO and market participants will use the new pre-dispatch schedule as the basis for planning and decision making. This provides a further opportunity to change the timing of the STEM auction, to move it closer to the trading day.

STEM timing will no longer be constrained by real-time market processes, and should instead be driven by participant needs, such as deadlines for making fuel nominations for the following trading day and lead times needed to commit long-start facilities. The gas nomination window has not changed, and discussions with participants have not identified any compelling need to change the STEM timeline.

Design approach

No change to STEM timing.

5. Treatment of demand side resources

Demand side resource (DSR) contribution to the wholesale market can come from three sources.

- **Generation:** A behind-the-meter generation facility, i.e. turning on an emergency diesel genset even though a grid connection is still present. This may appear to the system as a reduction in demand from that location, as a separately measured injection, or as complete disconnection from the network (where a facility has sufficient capability to manage its own load).
- **Consumption:** An electricity consumer with no associated generation, who has capability to make controlled changes in load (either up or down), i.e. a factory stopping production, a water pump ceasing to operate, or a commercial refrigeration unit lowering or raising the temperature setpoint of its facility
- **Storage:** A behind-the-meter system that can produce or consume energy within set bounds, i.e. a battery system, a flywheel, or a pumped hydro facility.

While each individual DSR will be at a single location, it is also possible for smaller resources to be aggregated together into a larger portfolio, either behind the same meter as part of a microgrid, or behind different meters as part of a virtual power plant.

This chapter deals with considerations around incorporation of DSRs into a security constrained, co-optimised market. Registration and participation considerations will be addressed in a later design paper.

5.1 DSR participation in the real-time market

Current approach

In the current wholesale market, demand side participation is explicitly incorporated in three ways.

- **Interruptible Loads.** These are loads that can be immediately and automatically curtailed in response to a change in system frequency. These facilities can provide a spinning reserve service equivalent to that provided by scheduled generators, where contracted by AEMO. There is one interruptible load registered in the market at present.
- **Intermittent Loads.** These are sites that have their own associated generation, whose contribution to system capacity is managed via a monitoring and payment process parallel to the standard RCM. Where the behind-the-fence generator supplying the intermittent load has greater capacity than required to service its associated load, it can be registered, scheduled and dispatched in the real-time market for this portion of its capacity.
- **Demand Side Programmes (DSP).** These are collections of individual loads anywhere on the network that provide last-resort services to the market. They are eligible for capacity credits, though not subject to the same availability requirements as scheduled generation. They are not dispatched as part of the core BMO, but rather included on a separate merit order that is only called on in extremis, with a single price for increment and decrement peak and off-peak. The last time a DSP was called upon was in June 2014, as a result of the Muja bus-tie transformer outages.

Rule change RC_2014_06 removed a further construct for dispatchable load, which could be dispatched up or down, again via a separate merit order from the standard BMO. No dispatchable loads were ever registered under these rules.

Demand side participation also occurs through participants managing their own consumption in response to projected system peaks that determine the calculation of IRCRs, though this is not managed through market dispatch. AEMO estimated⁵³ an IRCR-related demand reduction of between 41 MW and 77 MW in peak intervals between 2012 and 2018.

Future state

The current market design treats almost all DSR as only to be used in extremis. The demand side is not scheduled and dispatched in core market processes, even if it is capable of being so. This is the case even though, in some situations, it should be lower cost for the market to back off demand rather than increase supply.

In 2018, DSP demand decrease prices offered in the Non-Balancing Dispatch Merit Order have, without exception, been greater than the Balancing Price, consistent with being available only in extreme situations. This kind of system-wide last-resort load reduction service is still likely to be useful in future, but with projected increase in deployment of microgrid and advanced energy management solutions, the flexibility of DSR will increase. Allowing this capability to be fully recognised in market scheduling and dispatch processes could allow further efficiencies in overall supply costs, for example by enabling AEMO to dispatch load increases in the middle of the day to offset increasing rooftop solar injection. There are four main options for treating DSRs in a security constrained market.

1. Continue to separately dispatch DSRs as a last resort only, and allow intermittent loads to continue to participate for net positive dispatch only.
2. Allow DSRs to be dispatched in real-time essential system service markets, but not energy markets. Interruptible load is an extremely cost-effective source of contingency reserve in other markets.
3. Allow DSRs to participate in real-time energy scheduling and dispatch in a similar way to storage technologies.
4. Introduce full clearing of demand bids against supply offers, whereby all market customers submit bids to purchase energy, and these are matched with supply offers to set the market price and dispatch.

Because most demand is not flexible, it is not possible to hold all load to binding dispatch decisions. Unless dispatch positions are binding, bids to purchase are of limited value. It therefore makes sense to deal solely with the flexible demand through options 1 through 3.

⁵³ AEMO, 2018, WEM Electricity Statement of Opportunities. Accessible at: https://www.aemo.com.au/-/media/Files/Electricity/WEM/Planning_and_Forecasting/ESOO/2018/2018-WEM-ESOO-Report.pdf

Any DSR participation requires the facility to be held to a binding dispatch instruction. If a resource cannot be scheduled, it cannot be part of a DSR.

There are two main ways in which demand side capability is incorporated into energy markets around the world, namely:

- DSR reduction offers; and
- DSR consumption bids.

Each is discussed further below. DSR participation in essential system services markets will be addressed in a later design paper.

DSR reduction offers

In this option, demand side offers are treated by the market as full substitutes for supply side offers. DSRs are paid to reduce consumption below the level at which they would have otherwise consumed, treating them as a contribution to energy dispatch. Because there is a direct payment for reduction in consumption, demand side participants are more likely to be interested in market participation. This is the most prevalent approach to DSR participation around the world, and is how the current WEM DSP dispatch regime works.

However, this treatment gives rise to a ‘missing money problem’. When dispatching generation, there is a corresponding consumer who withdraws the same amount of energy. When dispatching load, there is no market customer on the other side of the transaction paying for consumption, there is simply a reduction in demand. Any payments to the DSR must therefore be recovered from consumers as an uplift. The compensation mechanism is attractive to DSR providers, but it is not equitable for other consumers.

This approach is not unreasonable for a service that functions as a last resort before involuntary load curtailment occurs, and is used as such in many markets. It is inequitable for general DSR participation in the real time market, as it effectively compensates load twice – once through the market, and once for the avoided costs of the energy they would otherwise have had to purchase. The higher the proportion of DSR to generation, the higher the uplift multiplier for recovery from other consumers.

DSR consumption bids

With DSR reduction offers, DSRs are being paid for reduction from a forecast position, with no firm market supply to back up their offer. With consumption bids, a DSR bids into the market for offtake at a specific price, and is scheduled along with generation. It is not directly paid for reduction, compensation comes from avoided costs of withdrawal.

This concept is very similar to how the STEM is cleared and would use very similar market mechanisms to those required for storage. The existing NEMDE clearing engine already includes consumption bid functionality.

Consumers always retain the ability to respond to price without submitting consumption bids. The overhead of market participation, including the more stringent requirement to comply with dispatch instructions, has meant that the uptake of this kind of functionality has been low in some other places. For example, the NEM has a Scheduled Load construct, but the only

facilities registered in this class are those associated with storage facilities – pumped hydro and batteries. New Zealand introduced dispatchable demand functionality in 2014, but only has a single DSR participating.

On the other hand, in markets where DSR can participate in capacity mechanisms, there is generally higher participation in real-time markets as well. PJM's Price Responsive Demand programme will see over 500 MW of participation in 2020, as stricter requirements for participation in its capacity market made some ineligible for payment through last-resort mechanisms.

Where there is a day-ahead market, facilities may be able to trade around their day-ahead consumption schedule. Participants can choose to set their bid prices based on day-ahead (or off-market contract) positions: effectively choosing not to consume, so as to resell their contracted energy to the market when the price reaches a certain point. Conversely, a participant could bid to increase consumption from its contracted position, and in order to be cleared when the real-time price is low. In the WEM, the presence of the STEM gives an opportunity for this sort of arbitrage.

The introduction of a Scheduled Load class would allow DSR to participate in the real-time market in a similar way to generation. Dispatch positions would be binding, and subject to dispatch compliance and monitoring.

Treatment of DSPs

To participate in the market as a Scheduled Load, the energy represented by the consumption bid must be settled in central market settlement. Existing DSPs are structured such that the owner of the DSP may be a different participant than is responsible for supplying energy to the component NMs. As a result, it will not be possible for DSPs to participate in the market as scheduled loads, and their contribution must continue to be treated as supply offers.

Nevertheless, DSPs can still be included in the central optimised clearing process, rather than dispatched via a separate merit order. Doing so will ensure the pre-dispatch schedule provides a complete view of expected market outcomes, including amounts of any expected DSP dispatch.

Under this process, each DSP would be represented in market offers as a single tranche with a quantity reflecting their capacity credit holdings⁵⁴. DSPs would be included in any interval where their RCOQ was non-zero. That means DSPs in Availability Class 1 would be included in every interval. Because the actual load of a DSP is not available in real time, the offer quantity would not be adjusted for actual DSP load at the time, and any shortfall in load when called would be handled through the reserve capacity refund process.

The price at which the DSP tranche is included in the clearing process depends on whether payment for DSP dispatch is retained.

⁵⁴ The RCOQ for a DSP reflects the capacity credits it holds, which represent AEMO's reasonable expectation of its availability in the required hours.

1. If DSPs are not paid for their dispatch (consistent with the ‘missing money problem’ discussed above), their ‘offer’ price would be set at the market price cap, ensuring that they are dispatched off as a last resort, instead of via a separate merit order. They would not be paid the energy price for dispatch – their compensation would come from capacity payments and the avoidance of high energy prices for their demand.
2. If DSPs continue to be paid for their dispatch, each DSP would continue to offer a ‘consumption decrease price’, which could be less than the market price cap. They would be paid the market energy price for each MWh of demand reduction, and this would give rise to the same ‘missing money’ issue as discussed above, whereby the cost recovery for DSP dispatch would have to be smeared across market participants.

Incorporating DSPs into the main market clearing engine will slightly increase the chances of being dispatched. Given the small number of DSPs currently existing, it is possible that the removal of explicit payments for DSP dispatch would discourage demand side participation in the WEM. However, as noted above, no DSP has been dispatched since 2014, so dispatch payments are unlikely to have formed a major part of facility entry decisions.

Design approach

In relation to DSR participation.

- Introduce a Scheduled Load structure into the WEM, allowing demand side participants to bid their controllable consumption into the market, and be dispatched alongside energy offers.
- Incorporate DSPs into central market clearing by including a ‘deemed offer’ in market clearing inputs for each DSP, with a quantity reflecting RCOQ, and a price of the market price cap. Allow DSP offers to set the market price, but do not pay a DSP dispatch instruction payment, to reflect that participants are compensated by avoiding payment of the high energy price.
- Provide a mechanism for DSPs to signal unavailability, or availability below RCOQ (to be described in a market procedure).
- Determine DSP dispatch instructions using the pre-dispatch schedule, committing them two hours ahead, using an inflexibility profile of the same kind proposed for fast-start generation facilities (section **Error! Reference source not found.**).

Contribution to market objectives

	Objective	Contribution
1.2.1(a)	Promote economically efficient, safe and reliable production and supply of electricity in the SWIS	Visibility of scheduled load increases the accuracy of market processes
1.2.1(d)	Minimise the long-term cost of electricity supplied to SWIS customers	More avenues for demand side participation reduces overall cost and increases incentives to reduce and shift demand
1.2.1(e)	Encourage measures to manage the amount of electricity used and when it is used	

5.2 Treatment of behind-the-fence generation in a security constrained market

Current approach

Intermittent loads are loads supplied by a dedicated generator that may be located behind or in front of the meter at the same site, or at a different location. They are subject to special treatment in market processes, included as a bidirectional connection point with potential for either withdrawal or connection, and settled as if the generator is located behind the meter.

The construct exists to allow large embedded generation to be accounted for in the capacity mechanism, contingency analysis and ancillary service dispatch and cost recovery, while not requiring self-supplied participants to participate in other aspects of the market. Participation in the real-time market is restricted to generation capacity over and above the registered load amount that is set at the time of registration, which will generally be higher than the amount actually self-supplied in any given interval.

There are currently seven intermittent loads registered in the WEM, and all have generation at the same location as load.

Future state

The reformed WEM will still need a mechanism for consumers to serve their own load without participating in central market processes. Increasing popularity of distributed energy sources and microgrids would drive an increase in the proportion of overall SWIS load being self-served. AEMO as system manager will continue to need visibility of behind-the-meter contingencies. Where microgrid setup is such that it any loss of behind-the-meter generation is automatically matched by behind-the-meter consumption reduction, it would not need to be visible to AEMO.

When network constraints are incorporated into dispatch decisions, retaining the option for an intermittent load to be made up of load and generation at different locations will not be sustainable. If retained, it would create a de-facto firm network capacity right at the expense of other users of the network.

Intermittent loads represent DSR facilities whose full capability is not available to the market. In the current market, if demand is lower than the notified level, the spare capacity of the behind-the-meter generator cannot be provided into the market, even where it is cheaper than the marginal market generator. Having this supply available could lower the overall cost of supply. This capability could be implemented by a similar mechanism to storage dispatch.

Design approach

Restrict the registration of intermittent loads to generators co-located with the load they serve.

Allow intermittent loads to offer withdrawal as well as injection.

Contribution to market objectives

	Objective	Contribution
1.2.1(a)	Promote economically efficient, safe and reliable production and supply of electricity in the SWIS	Allowing intermittent load to offer withdrawal increases the resources available to the market, contributing to reliability, lowering costs, and incentivising time-shifting of energy
1.2.1(d)	Minimise the long-term cost of electricity supplied to SWIS customers	
1.2.1(e)	Encourage measures to manage the amount of electricity used and when it is used	

5.3 Aggregation of distributed demand side resources

Grid-scale DSR is not the only potential provider of services in the wholesale market. While aggregation of commercial and industrial loads for use in the wholesale market services has a long history, aggregation of household level resources is new. Technology exists today to aggregate household level batteries and electric vehicles into a ‘virtual power plant’, and in future, aggregation of sub-household level smart appliances will also be possible. Whether this technology is used to offer services into the wholesale market or used in other ways remains to be seen.

Current approach

Consistent with the current unconstrained dispatch of generation, the DSP construct allows loads from anywhere on the system to be aggregated together into a single facility. Standing data for the facility includes the connection point of individual loads within the programme, so this information is available to the System Manager. The market does not have visibility of the location of individual loads within the DSP.

There is no requirement for AEMO to consult with a network operator prior to registering a facility comprising aggregated DSR.

Future state

In a security constrained market, where network and security constraints are a key driver of dispatch decisions, the location of facility response is critically important. It has already proven important in the current market arrangements in certain circumstances. During the Muja bus-tie transformer issues in 2014, the current DSP construct proved difficult to use to support system security. Calling a DSP per the market rules would not have addressed the location-specific issues on the power system. In practice, the system operator and the DSP owner worked together to identify and call upon specific loads associated to the DSP, based on their geographic location. Without this cooperation, calling a DSP could have worsened the already compromised state of the power system.

One response would be to restrict DSR aggregation to resources at a specific electrical location – where individual DSRs contribute to load at the same ‘point of connection’. For

wholesale market purposes, this could mean electrically in the same location on the transmission network, as defined by the substation (or group of substations) they are fed by. This approach is used in California, where all DSR in a single aggregation must be connected to the same Load Aggregation Point, of which there are 24 across the state.⁵⁵ Similarly, ISO New England requires all DSR within an aggregation to be within the same dispatch zone, of which there are 19 across the market.

However, the WEM is a much smaller market than either California or New England, roughly equivalent to the peak demand of two California Load Aggregation Points. If demand side participation in the WEM remains effectively a last resort before load shedding, the location of the participating DSR is less important than the size of the programme. Placing geographic restrictions on participation would make it harder for prospective DSR aggregators to deliver a programme of sufficient size to be useful for system reliability purposes.

For this reason, it is proposed that facilities comprising aggregated DSRs will not be restricted by electrical location. As more DSR joins the market, this requirement can be revisited.

If many of the DSRs comprising an aggregated DSR facility are very close together (i.e. on the same distribution feeder), wholesale market operation may cause problems for the network operator. In such cases, there may be a need for the network operator to review proposed DSR aggregation as part of registration processes.

Design approach

An aggregated DSR facility comprising DSRs at the same electrical location can fully participate in market processes as a Scheduled Load.

An aggregated DSR facility comprising DSRs from multiple electrical locations can participate in market processes as:

- a Scheduled Load that must bid any quantity at the market price cap; or
- a DSP.

AEMO must consult with the relevant network operator for any aggregated DSR facility with more than a certain threshold⁵⁶ of DSR at the same electrical location

DSPs must continue to provide the location of each load in the programme, and AEMO has discretion to call on a subset of loads in an emergency situation, in consultation with the DSP owner.

⁵⁵ California ISO, Information on distributed energy resource providers. Accessible at: <http://www.caiso.com/participate/Pages/DistributedEnergyResourceProvider/Default.aspx>

⁵⁶ For example, 0.2 MW, to align with the minimum threshold for registering as a Scheduled Generator

Contribution to market objectives

	Objective	Contribution
1.2.1(a)	Promote economically efficient, safe and reliable production and supply of electricity in the SWIS	Requiring co-location for full market participation minimises risks to system security in SCED
1.2.1(d)	Minimise the long-term cost of electricity supplied to SWIS customers	Retaining option for last-resort provision of system-wide demand reduction allows greater participation, reducing overall costs

Appendix A Market Schedule Timelines

This appendix shows key milestones and schedule horizons for proposed market schedules.

Figure 1: Key market scheduling and dispatch milestones

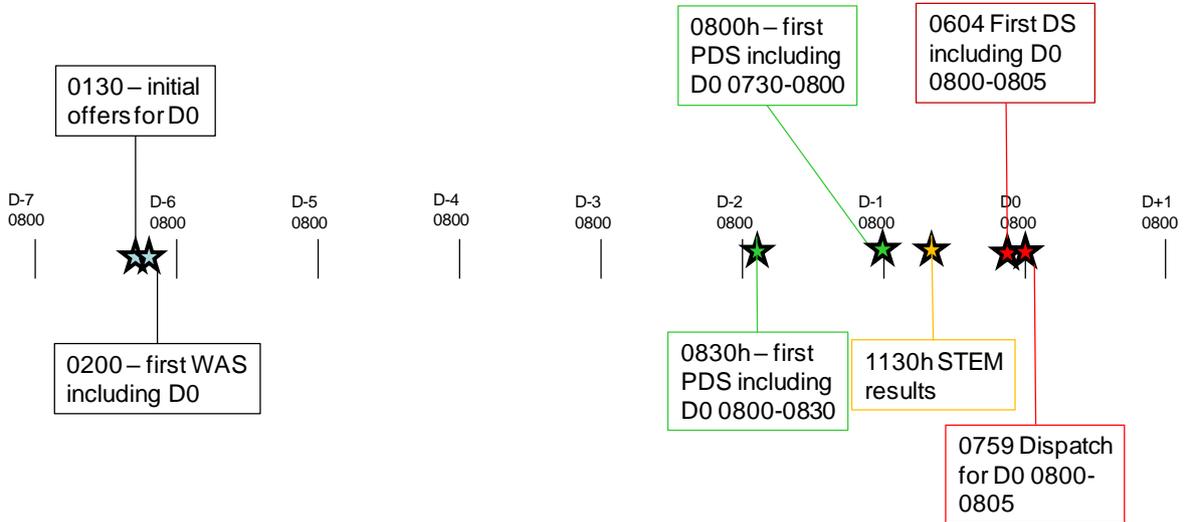


Figure 2: Week ahead schedule horizons

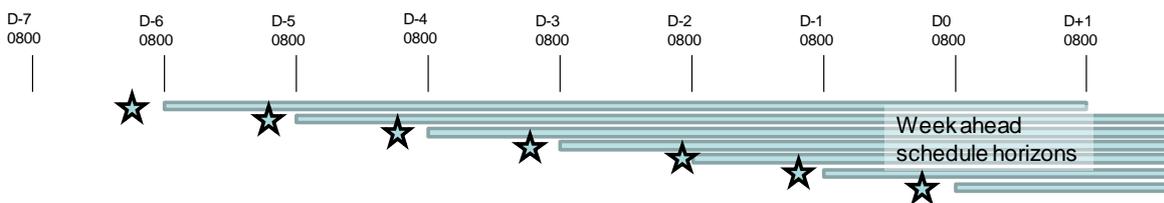


Figure 3: Pre-dispatch schedule and STEM horizons

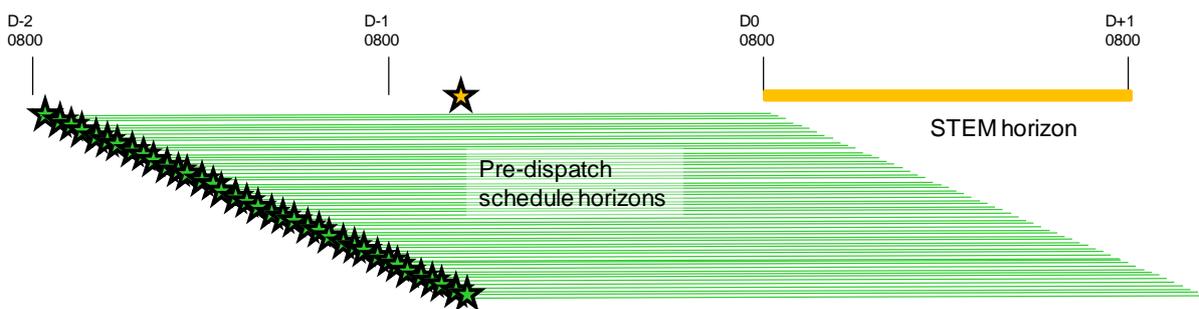
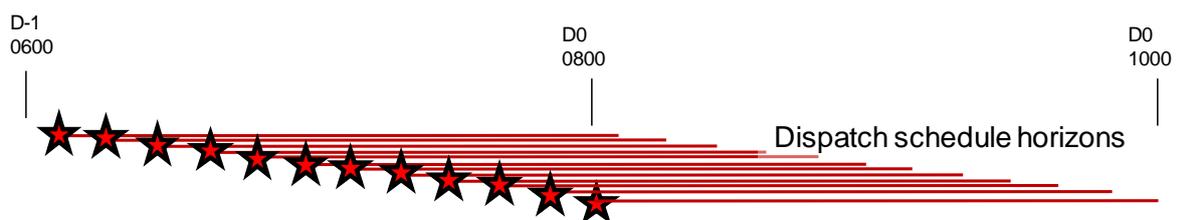


Figure 4: Dispatch schedule horizons



DS = Dispatch Schedule
PDS = Pre-Dispatch Schedule