AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

Wholesale Electricity Market Design Summary

September 2023

A report describing the Wholesale Electricity Market in the South West Interconnected System

Important notice

Purpose

AEMO is the Market Operator of the Wholesale Electricity Market (WEM) and System Manager of the South West Interconnected System (SWIS). This publication has been prepared by AEMO to provide a high-level summary of the design of the WEM using information available at 31 July 2023. Information made available after this date may have been included in this publication where practical.

The WEM is currently undergoing additional reform in various areas, meaning that the WEM Rules will be regularly updated to reflect the outcomes of various reform workstreams. Readers should consider the validity of information in this document against the current version of the WEM Rules.

If the reader finds information that it believes is inaccurate, misleading or out-of-date, they are encouraged to contact AEMO at wa.marketdevelopment@aemo.com.au.

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Version control

Version	Release date	Changes
0.1	27/5/2021	Initial document publication using provisional information published by the Western Australian Government as part of its Energy Transformation Strategy.
1.0	30/3/2022	Updates to incorporate reform tranche 4 and 5 Rule changes
2.0	08/09/2023	Updates to incorporate reform tranche 6 and 6A and supplementary capacity procurement Rule changes.

AEMO acknowledges the Traditional Owners of country throughout Australia and recognises their continuing connection to land, waters, and culture. We pay respect to Elders past and present.

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1 Introduction

1.1 Purpose of the Market Design Summary

This document aims to give readers a high-level understanding of the design and operation of the Wholesale Electricity Market (WEM) for the South West Interconnected System of Western Australia (SWIS) following New WEM Commencement Date. It describes the various components of the market, their purposes and objectives, and how they interact with each other[1].

Market design information on the pre-reform market is available on AEMO's website.

This document is a simplification of the WEM Rules and WEM Procedures, and in many cases generalises or elides detail to aid reader understanding. For more detail, readers are directed to the WEM Rules and WEM Procedures, which provide a complete and definitive description of the market[2].

Capitalised terms in this document have the same meaning as in the WEM Rules. Acronyms are defined at first use and in the Glossary at the end of this document.

1.2 History of the WEM – 2006 to 2023

The WEM is implemented and operated according to the WEM Objectives set out in section 1.2 of the WEM Rules (and discussed in Section 3.1). The WEM facilitates competition and private investment in the supply of electricity while ensuring secure and reliable electricity supply to customers at the least cost over the long term. It allows producers and consumers of electricity flexibility as to how they buy or sell electricity and who they trade with. The market commenced operation in September 2006, and was initially focused on forward planning, introducing:

- The **Reserve Capacity Mechanism (RCM)** through which the market operator procures capacity to ensure that adequate generation and demand-side management (DSM) capability is available to meet demand for electricity.
- The **Short-Term Energy Market (STEM)**, a centrally cleared day-ahead market for Market Participants to adjust their contractual positions for energy by trading with each other.
  - The incumbent state-owned generator (Synergy) managed variations between day-ahead market outcomes and real-time demand and provided all Ancillary Services at administered prices (although there were a small number of Bilateral Contracts between the system operator and other providers).

[1] The WEM is currently undergoing additional reform in various areas such as (but not limited to) DER participation, treatment of load and the RCM This means that the WEM Rules will be regularly updated to reflect the outcomes of various reform workstreams. Readers should consider the validity of information in this document against the current version of the rule book. If the reader finds information that it believes is inaccurate, misleading or out-of-date, they are encouraged to contact AEMO at wa.marketdevelopment@aemo.com.au

[2] A copy of the most recent version of the Wholesale Electricity Market Rules is available on the Energy Policy WA website, at https://www.wa.gov.au/government/document-collections/wholesale-electricity-market-rules. WEM Procedures are developed by, and published on the websites of, the Coordinator of Energy (at https://www.wa.gov.au/organisation/energy-policy-wa, the Australian Energy Market Operator (AEMO), at https://aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/procedures-policies-and-guides/procedures, the Economic Regulation Authority (ERA), at https://www.erawa.com.au/electricity/wholesale-electricity-market/market-procedures, and Western Power, at https://www.westernpower.com.au/.

In 2012, additional mechanisms were introduced to improve competition for the real-time procurement of Market Services, with:

- The competitive gross pool **Balancing Market** operating every half-hour to schedule supply from all generators in the SWIS (with Synergy offering as a Portfolio, with individual Facility dispatch within the Portfolio determined by the system operator). This allows Market Participants a near-real-time opportunity to trade the differences between their contractual positions and physical outcomes.
- The competitive **Load Following Ancillary Service (LFAS) market**, through which the market operator could procure frequency regulation services from participants other than Synergy. Other Ancillary Services were still provided by Synergy or through Bilateral Contracts with the system operator.

Through this whole period, generator access to the Network was provided on an unconstrained basis and Facilities connecting to the Network were obliged to fund network augmentation to maintain the unconstrained access of incumbents.

1.3 A new market design – 2023 and beyond[3]

In recent years, the SWIS has started a transformation driven by changes to the mix of grid-connected large-scale generation technologies, changes in consumer demand patterns, and growth in the penetration of distributed energy resources (DER), such as solar photovoltaics (PV) and battery storage systems, connecting 'behind-the-meter' on commercial and residential sites.

In particular:

- Increasing penetration of behind-the-meter rooftop PV generation — collectively the largest generation system in the SWIS — is leading to significant changes in demand patterns, with system peak demand now occurring later in the day than in the past. At the same time, generation ramping requirements in the late afternoon and early evening are growing steeper, as reduced output from solar PV systems (as solar irradiance falls) coincides with an increase in household demand.
- Increasing penetration of large-scale intermittent generation in areas of the SWIS where transmission capacity is constrained has also resulted in challenges in managing the power system. While overnight demand has remained low relative to peak demand over the last decade, wind power has increasingly displaced output from baseload generators with higher fuel costs during these times. Under an unconstrained dispatch model, this situation requires:
  - Controllable generation to be dispatched 'out of merit' to maintain Power System Security (PSS), displacing lower-priced wind output at significant cost to customers, and
  - Significant medium- to long-term network investment to accommodate increasing renewable energy and mitigate congestions costs.
- The impact of the increasing penetration of large-scale intermittent generation and DER-driven low daytime demand has also led to a significantly higher prevalence of negative pricing. In the absence of changes to the WEM and its underpinning frameworks, this continuing trend would likely have challenged the technical operation and continued viability of conventional generation technologies.

[3] This section is paraphrased from material published by the Energy Transformation Task Force, at https://www.wa.gov.au/sites/default/files/2019-08/Information-Paper-Foundation-Market-Parameters.pdf.

The Western Australian government recognised that:

- The historical market and ICT systems used to manage the power system needed to evolve to reflect physical Constraints of the Network and efficient delivery of energy and Essential System Services (ESS)[4], to avoid increasing quantities of generation being dispatched out of merit order, and increased costs being borne by customers.
- The expected increase in manual interventions and unintegrated mechanisms to manage fluctuating intermittent output would be costly and come with increased risk of unintentional errors.
- The changing generation mix means it can no longer be assumed that the inherent technical characteristics of conventional generators will continue to ensure the maintenance of Power System Security (PSS). Conventional thermal generators have traditionally provided important additional power system services, such as Inertia, which assists with frequency control. However, conventional generators may not remain the most available or most economic source of providing such ESS in the future.
- The historical framework of Regulations and WEM Rules underpinning the maintenance of PSS and Power System Reliability (PSR) were no longer fit for purpose. Changes to PSS and PSR standards and planning processes, as well as changes to the procurement and type of ESS provided to the market, are required to manage the system as the generation mix, technology, and customer behaviour continue to change.
- The unconstrained network access framework was resulting in significant connection delays and inefficient use of the Network.

To address these challenges, the amended WEM features:

- Network access on a constrained basis, removing the obligation for new entrants to fund augmentation, reducing barriers to entry, and increasing the utilisation of the Network.
- New definitions of ESS to ensure future PSS and PSR challenges are addressed appropriately, including allowing for the participation of new technologies.
- Centralised security constrained scheduling and dispatch in a Real-Time Market (RTM) to maximise economic efficiency in a way that respects power system Constraints and ESS requirements, including Facility-level dispatch of Synergy Facilities.
- A Supplementary Essential System Service Mechanism (SESSM) to facilitate procurement of ESS via longer-term arrangements in case of inadequate supply in the RTM.
- Changes to the RCM so that:
  - Capacity procurement accounts for Network Constraints, while providing long-term certainty of capacity revenue for incumbent Facilities.
  - Capacity certification processes allow for new technologies such as Electric Storage Resources and hybrid Facilities to participate in the capacity market.
- Integration of DER to market mechanisms through the ongoing work on the DER Roadmap[5].
- Consequential changes to market settlement calculations and processes.

[4] Historically known as Ancillary Services, with the name change reflecting that such services are increasingly essential to energy supply rather than being ancillary.

[5] https://www.wa.gov.au/government/distributed-energy-resources-roadmap

1.4 Structure of this document

This report is structured as follows:

- **Chapter 2** introduces the basic features of the market to set the context for subsequent sections.
- **Chapter 3** describes the roles of the key parties in market governance.
- **Chapter 4** describes the administration of the market.
- **Chapter 5** describes the various classes of market participation along with Facility registration requirements.
- **Chapter 6** covers PSS and PSR issues, including Outage planning and SESSM.
- **Chapter 7** describes the RCM.
- **Chapter 8** covers the RTM for energy and ESS.
- **Chapter 9** describes the STEM.
- **Chapter 10** describes settlement processes, including metering.
- **Appendix A1** provides a summary of the various processes in the market and indicates who administers and participates in each process.
- **Appendix A2** provides examples of dispatch outcomes in situations where a Facility is dispatched to provide ESS where it would not have been dispatched if it was solely providing energy.
- **The Glossary** provides definitions for acronyms and some WEM Rule terms.

2 A brief overview of the market

2.1 The market entities

The market comprises the following entities.

- The **Coordinator of Energy (Coordinator)** is established under the Energy Coordination Act (2004) and is tasked with providing advice and support to the Minister of Energy on all aspects of energy policy and with the planning and coordination of energy provision in WA. The Coordinator is supported by Energy Policy WA (EPWA), a division of the Department of Mines, Industry Regulation and Safety also responsible for advising the Minister for Energy on energy policy. The Coordinator is responsible for the development of the WEM, including overseeing and administering changes to the WEM Rules. At least once every five years, the Coordinator publishes the Whole of System Plan (WoSP) to inform efficient long-term network and generation investment under a range of scenarios.
- The **Australian Energy Market Operator (AEMO)** is responsible for the operation of the WEM and the secure and reliable operation of the SWIS. It operates the various trading mechanisms (e.g. markets for energy and ESS and the RCM), conducts short- and medium-term system planning (including Outage planning), and dispatches Facilities comprising Energy Producing Systems and/or Loads to meet power system needs in accordance with the WEM Rules. AEMO also forecasts long-term Power System Adequacy to support the RCM.
- A **Network Operator** is a party that operates a transmission or distribution Network within the SWIS. A Network Operator is the default Metering Data Agent (the party that provides electricity meter data to AEMO) for its networks, but where a Network Operator is not Western Power it can opt out of this role in favour of Western Power. Western Power (the state-owned transmission and distribution network company) is currently the only registered Network Operator in the SWIS.
- A **Market Participant** is a party that transacts in the WEM, whether buying or selling energy, or providing ESS or capacity. Participants must apply to register all Facilities above 5 megawatts (MW). Facilities between 5 MW and 10 MW may be exempted by AEMO. Electricity retailers must be a registered Market Participant to purchase energy in the WEM.
- The **Economic Regulation Authority (ERA)** is the independent regulator responsible for oversight of the WEM. The ERA monitors market effectiveness, monitors Rule Participants' compliance with the WEM Rules and initiates enforcement action. The ERA also conducts periodic reviews of certain market processes and may trigger the SESSM if procurement in the RTM is insufficiently competitive.
- **Synergy** is the state-owned electricity generation and retail business. It is generally treated the same as any other Market Participant. The main exception is that it is the only retailer allowed to serve customers with annual demand of less than 50 megawatt hours (MWh) (termed Non-contestable Customers), requiring a different treatment of the load of these customers in settlement.

Market Participants, Network Operators, and AEMO are all classes of Rule Participant. Becoming a Rule Participant requires an entity to comply with the WEM Rules. Rule Participants that trade in the RCM, the energy market or provide ESS are automatically Market Participants. More information on the different functions of these entities is provided in Appendix A1 of this paper.

2.2 The trading mechanisms

The various WEM trading mechanisms are briefly summarised below.

2.2.1 Reserve Capacity Mechanism

The primary role of the RCM is to meet reliability requirements by ensuring sufficient capacity (or Reserve Capacity) is available to meet system demand and maintain ESS requirements during peak demand events. The RCM is intended to contribute towards the fixed costs of providing capacity.

The RCM operates on a three-year cycle. In the first year, AEMO assigns Capacity Credits to suppliers of registered capacity who are expected to be available to provide supply to meet the expected peak system demand two years in the future.

Eligible suppliers are issued Capacity Credits for their Facilities and must make that capacity available to the market during the relevant Capacity Year (that is, from 1 October (Year 3) to 30 September (Year 4) of the relevant Reserve Capacity Cycle. Suppliers that choose not to bilaterally contract their Capacity Credits are paid for their Capacity Credits at an administered Reserve Capacity Price (RCP). Capacity Credit holders pay refunds if they fail to make capacity available.

If AEMO considers that inadequate Reserve Capacity will be available in the SWIS to maintain PSS and PSR, it can procure supplementary capacity from Market Participants and others by direct contract.

Payments to capacity suppliers are funded by Market Participants in proportion to their Individual Reserve Capacity Requirements (IRCR). Participants can agree Bilateral Contracts for Capacity Credits at prices other than the administered RCP. If an over-capacity situation arises, then the cost of the excess capacity is shared across all Market Participants in proportion to their IRCR.

The various features of the RCM are further described in Chapter 7.

2.2.2 Bilateral Contracts

Market Participants can enter into contractual agreements with each other to buy and sell energy and Capacity Credits through off-market mechanisms. Market Participants can submit Bilateral Contract data to AEMO to have the transactions accounted for in market settlement. See also Chapter 9.

2.2.3 The Short-Term Energy Market

The STEM is a daily forward market for energy that allows Market Participants to trade around their bilateral energy position, producing a Net Contract Position (NCP). See also Chapter 9.

Market Participants provide bilateral energy trade quantities, and supply and demand curves for each 30-minute Trading Interval of the Trading Day. AEMO uses the Bilateral Contract data to determine each participant’s Net Bilateral Position (NBP), and the supply and demand curves to determine STEM Offers and STEM Bids for each participant relative to its NBP for each Trading Interval. A STEM Offer is an offer to increase the net supply of energy beyond the NBP, while a STEM Bid is a bid to decrease the net supply of energy relative to that position. AEMO runs the STEM Auction for each Trading Interval of the next Trading Day, determining a STEM Clearing Price and clearing quantities for market settlement. The combined NBP and STEM position of a Market Participant describes its NCP, which also flows through to market settlement.

2.2.4 The Real-Time Market

The RTM is a gross pool dispatch mechanism for energy and ESS (see Section 2.3). All Registered Facilities must participate and comply with the resulting Dispatch Instructions issued by AEMO.

Market Participants make RTM submissions specifying prices at which their Registered Facilities are available to be dispatched for various quantities of energy and ESS.

Using these submissions, plus the Load Forecast, ESS requirements, and Constraint Equations representing network configuration, AEMO runs a Dispatch Algorithm to determine the least cost method to dispatch Facilities in each five-minute Dispatch Interval to meet demand, while respecting Network Limits and maintaining PSS, and issues corresponding Dispatch Instructions to Scheduled Facilities and Semi-Scheduled Facilities.

AEMO uses the output of the Dispatch Algorithm to identify the marginal cost of supply for energy and Frequency Co-optimised Essential System Services (FCESS) at the Reference Node (Perth Southern Terminal) or the 'Market Clearing Price' for energy for each Dispatch Interval. For settlement purposes, AEMO averages the five-minute Market Clearing Prices for energy in a 30-minute Trading Interval to calculate the Reference Trading Price[6]. Market Participants receive this Reference Trading Price for any quantity above their NCP and pay this Reference Trading Price for any quantity below their NCP. Market Participants may be eligible for Energy Uplift Payments (see Chapter 10) where there is network congestion between their Facility's location and the Reference Node. Participants providing FCESS are paid based on the Market Clearing Price for those services in each Dispatch Interval. See also Chapter 8.

2.3 Essential System Services

ESS are required to maintain security and reliability of supply, thereby supporting the energy market. For example, they are used to regulate frequency and respond to Contingency Events on the power system. AEMO is required to procure adequate quantities of ESS to meet the Frequency Operating Standards (FOS). There are three types of ESS: Frequency Co-optimised, Non-Co-optimised and System Restart Services.

FCESS are procured in the RTM from accredited Facilities. They include Regulation[7], Contingency Reserve[8], and Rate of Change of Frequency (RoCoF) Control Service (RCS). If insufficient FCESS is projected to be available in the RTM, AEMO can trigger longer-term procurement of FCESS through the SESSM[9]. The ERA can also trigger the SESSM where FCESS market outcomes are inconsistent with competitive provision.

Non-Co-Optimised Essential System Services (NCESS) can be procured by AEMO or the Network Operator, on approval or direction from the Coordinator. They are required to support other system and network needs, such as locational services used to substitute for network upgrades, or a Minimum Demand Service to mitigate challenges around DER-driven low daytime loads. These are procured by the relevant entity through contestable contracts from capable providers.

[6] This will cease when the WEM moves to 5-minute settlement.

[7] Comprising Regulation Raise and Regulation Lower.

[8] Comprising Contingency Reserve Raise and Contingency Reserve Lower.

[9] The SESSM is a mechanism for procuring ESS capability over a longer timeframe than provided for in the RTM. SESSM procurement is only triggered in cases of a shortfall of ESS capable Facilities in the RTM, or if the ERA reasonably believes that RTM outcomes are not consistent with efficient operation. Facilities holding SESSM Awards can be paid an Availability Payment to offer their capability into the RTM with a pre-specified offer price cap (not including start-up costs), and face refunds if they do not perform according to the award terms.

System Restart Services (SRS) are a specific form of NCESS. AEMO procures SRS in the unlikely event that it will need to restart the system following a widespread blackout of the SWIS (a 'system black' event). AEMO procures these services contractually under the framework in the WEM Rules.

2.4 Facility Classes and characteristics

Entities are either mandated to register or can optionally register themselves as Market Participants and their Facilities in various Facility Classes in the WEM. Facilities must be registered if they are to provide services such as energy, ESS, and Reserve Capacity. See Chapter 5 for full details on Facility registration.

Facility Technology Types

A Facility is made up of one or more Facility Technology Types. The Facility Technology Types are:

- A distribution system;
- A transmission system;
- An Intermittent Generating System;
- A Non-Intermittent Generating System;
- An Electric Storage Resource; and
- A Load.

Most Facilities are defined at the network connection point level, being a group of Facility Technology Types electrically connected behind one or more shared network connection points. For example:

- A combined-cycle gas turbine (CCGT) at a single network connection point.
- A hybrid system comprising an Intermittent Generating System and an Electric Storage Resource electrically connected behind two shared network connection points.
- One or more Loads behind a single network connection point.

Some Facilities fit into special categories, including:

- A transmission system or a distribution system is a Facility in its own right and can be registered in the **Network Facility Class** (with the Network owner having to register in the Network Operator Rule Participant class).
- A **Small Aggregation** comprises distribution connected technologies at a single Electrical Location.

Facility Classes

The following classes of Facilities (excluding the Network Facility Class noted above) can be registered in the market:

- A **Scheduled Facility** must be fully controllable, such that it can be relied upon to comply with Dispatch Targets to maintain its Injection or Withdrawal at a specified level for at least the length of time specified in the relevant WEM Procedure. A Facility deemed to be fully controllable by AEMO must be registered in the Scheduled Facility Class.

- A **Semi-Scheduled Facility** must be partially controllable, such that it can comply with a Dispatch Cap. Facilities can only register in this class as determined by AEMO's controllability assessment and are still required to comply with Dispatch Targets to maintain a specified level when providing FCESS.
- A **Non-Scheduled Facility** comprises an Energy Producing System with a System Size less than 10 MW that is not required to comply with Dispatch Targets or Dispatch Caps but must respond to Directions during system emergencies. For example, aggregated DER.
- An **Interruptible Load** comprises one or more Non-Dispatchable Loads that can provide Contingency Reserve Raise ESS by interrupting their supply from the Network when they detect that system frequency has deviated from the target band. An Interruptible Load is compensated solely via ESS payments.
- A **Demand Side Programme** (DSP) comprises one or more Non-Dispatchable Loads that can be curtailed on request by AEMO. When curtailed, the Facility does not receive a payment from the market; its curtailed consumption is settled at the prevailing Reference Trading Price. DSPs are compensated solely by Reserve Capacity payments.

Each unregistered energy consuming or producing connection point will be included in settlement processes as a 'Non-Dispatchable Load'[10]

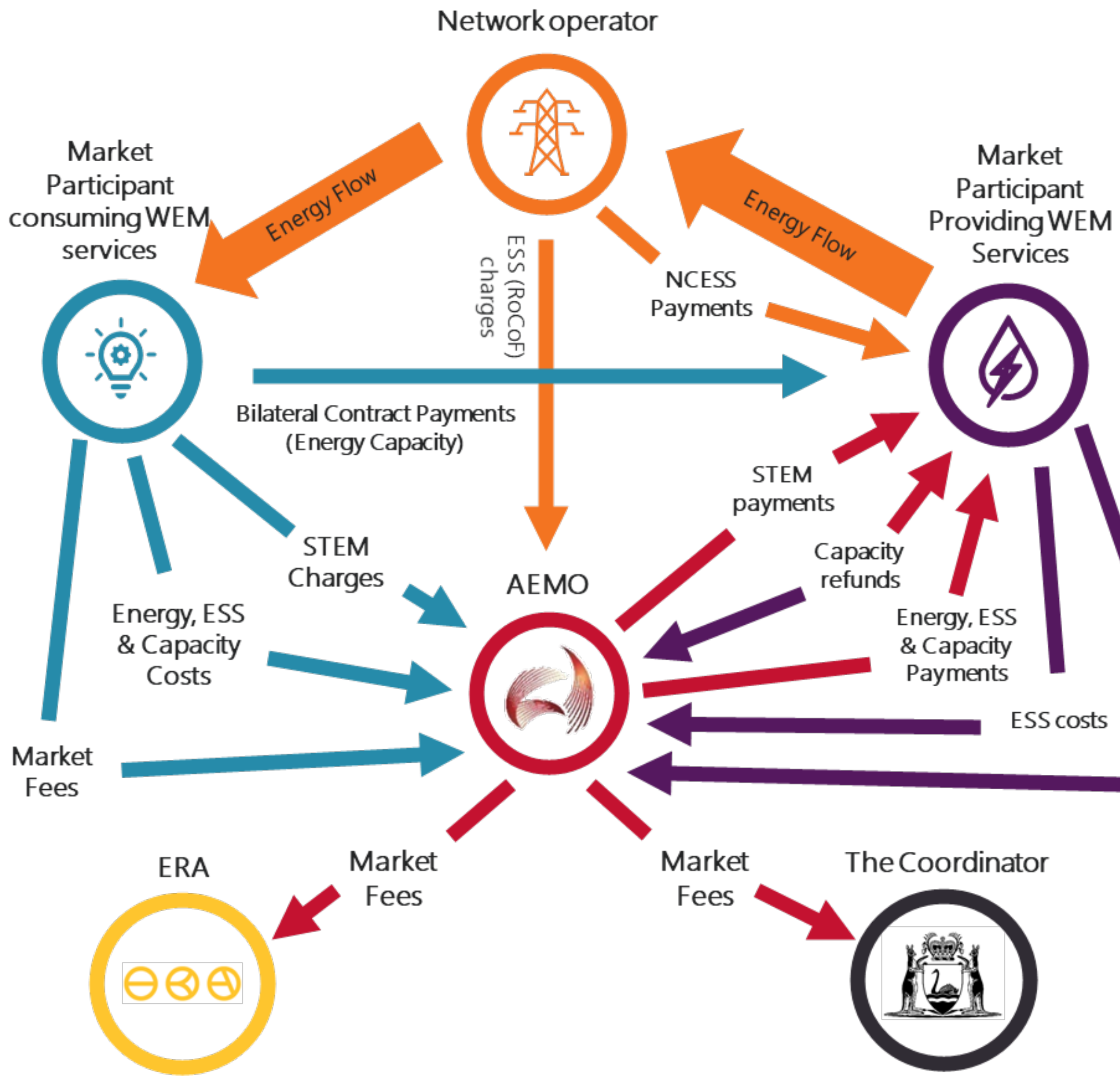
2.5 Market settlement

Market Participants settle WEM transactions with AEMO. Market Participants buy and sell energy or capacity via the various WEM trading mechanisms operated by AEMO. Additionally, AEMO pays Market Participants for ESS procured via the RTM, the SESSM, and direct contracts, and passes those costs through to Rule Participants according to the cost recovery rules. Bilateral contracts for energy and capacity are settled outside the market between the relevant counterparties, as are payments to Market Participants for any NCESS procured by the Network Operator.

AEMO is responsible for performing settlement calculations and for invoicing and settling with Rule Participants. Figure 1 provides a simplified view of the major settlement cash flows.

[10] A Non-Dispatchable Load is an unregistered Facility comprising one or more uncontrollable Loads (for example, commercial and industrial Loads or households).

Figure 1 Settlement cash flows[11]



Most energy is traded outside the AEMO administered market via Bilateral Contracts between Market Participants. These Bilateral Contracts can have energy and capacity components. By trading energy and capacity bilaterally, Market Participants can reduce their exposure to market prices. Where energy and capacity are traded bilaterally, AEMO reduces the market payments and charges for the relevant Market Participants accordingly.

Market Participants can modify their bilateral energy position through trading in the day-ahead STEM, forming an NCP. Differences between actual net energy supplied or consumed and NCP quantities are settled using the Market Clearing Prices determined in the RTM.

ESS costs are passed on to those participating in the market, with a slightly different approach for each service. Some FCESS services (for example, Contingency Reserve Raise) are cost-recovered from participants based on the extent to which they have created the need for procuring the service. Other services (for example, Regulation)

[11] NCESS payments from Network Operator to WEM Participant are in relation to services required for network operation and procured by the Network Operator. On the other hand, NCESS payments provided to support market operations (procured by AEMO) are paid by AEMO as part of ESS settlement.

are recovered based on energy volumes. The cost of NCESS procured by AEMO is also recovered on the basis of energy volumes, while the cost of NCESS procured by the Network Operator is not recovered through market processes.

Settlement of all transactions occurs on a weekly basis, around four weeks after the end of the relevant Trading Week. Settlement adjustments will be made up to 12 months after the relevant Trading Week, allowing for resolutions of disagreements and improved meter data.

Market Participants must meet prudential requirements for participating in the market. A Market Participant must maintain Credit Support to cover AEMO's estimate of the maximum amount that the participant is likely to owe AEMO during any 35-day period, which is based on historical information and allows for expected levels of Bilateral Contract coverage.

If at any time a Market Participant has inadequate Credit Support, AEMO may issue a Margin Call, and the participant will be required to provide further Credit Support. Failure to do so may result in the Market Participant being declared to be in default. AEMO has the power under the WEM Rules to impose firm measures on a party in default, such as suspension from the market.

When there is a default in payment to AEMO and Credit Support is inadequate to cover it, AEMO temporarily reduces payments in market settlement to reflect the shortfall. If the amount is not recovered quickly then the Outstanding Amount will be recovered by a Default Levy. Default is a very rare event.

3 Market Governance

Several bodies are tasked with overseeing, administering, running, and monitoring the WEM. Responsibilities are divided between key parties to provide checks and balances, providing confidence to Market Participants and consumers that market outcomes are impartial, transparent, and efficient.

3.1 The WEM Objectives[12]

The objectives of the WEM are laid out in Chapter 1 of the WEM Rules. These foundational principles guide the operation and evolution of the market and provide a framework for making decisions.

The WEM Objectives are:

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

3.2 The Coordinator of Energy

The Coordinator has overall responsibility for policy, market development, strategic planning, and overall coordination of the energy sector in Western Australia. The Coordinator is supported by EPWA, the state government energy policy body. EPWA and the Coordinator report to the Minister for Energy.

The Coordinator's functions are detailed in clause 2.2D.1 of the WEM Rules and include:

- Administering the WEM Rules.
- Developing amendments to the WEM Rules and administering the rule change and Procedure Change Processes.
- Progressing the evolution and development of the WEM and the WEM Rules in consultation with the Market Advisory Committee.

[12] As part of Project Eagle which seeks to improve governance of energy legislation and governance, the Electricity Act is being amended to include a State electricity objective The State electricity objective is to promote efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers of electricity in relation to —

- the quality, safety, security and reliability of supply of electricity; and
- the price of electricity; and
- the environment, including reducing greenhouse gas emissions.

The WEM objectives will be amended in the near future to align with the State electricity objective.

- Developing and maintaining relevant WEM Procedures..
- Developing and maintaining the constitution of the Market Advisory Committee (see Section 3.6) and appointing its members.
- Publishing a WoSP for the SWIS at least once every five years, including modelling various Scenarios over a 20-year horizon (see Section 6.4.1).
- Triggering the procurement of NCESS in accordance with section 3.11A.
- Providing input into the development of the Transmission System Plan (see Section 6.4.2) by the Network Operator.
- Determining the confidentiality status for Market Information in the event of a dispute (see also Section 4.3)
- Providing independent oversight for certain market processes by conducting periodic reviews of:
  - General market effectiveness, including:
    - Market design problems or inefficiencies (with assistance from the ERA);
    - the effectiveness of compliance monitoring and enforcement measures;
    - the effectiveness of AEMO in carrying out its functions; and
    - the effectiveness of Network Operators in carrying out their functions.
  - The Planning Criterion used to determine the Reserve Capacity Target.
  - The approach to certifying Reserve Capacity for Electric Storage Resources.
  - ESS Standards and the basis for setting ESS requirements.
  - The Outage planning process.
  - The supplementary capacity mechanism.

The Minister for Energy may issue the Coordinator with a statement of policy principles for the development of the WEM, but it must be consistent with the WEM Objectives.

During the transition to the new WEM, the Coordinator administered a dispute resolution mechanism for the agreement of Generator Performance Standards (GPS) for existing Facilities.

3.3 Australian Energy Market Operator

AEMO is the market operator for the WEM and the system operator for the SWIS. AEMO must ensure that the SWIS operates in a secure and reliable manner.

AEMO's WEM functions are detailed in section 2.1A of the WEM Rules and include:

- Market and power system planning:
  - Assessing generation and DSM capacity adequacy over the long term.
  - Coordinating Planned Outages of generation, storage, and network equipment.
  - Assessing system adequacy and security over short- and medium-term timeframes.

- Market and power system operations:
  - Processing applications for participation, and for the registration, de-registration, transfer, and ESS accreditation of Facilities.
  - Operating the RCM, including the procurement of supplementary capacity as required.
  - Operating the STEM.
  - Operating the RTM and issuing Dispatch Instructions to Market Participants.
  - Procuring, scheduling, and dispatching sufficient ESS to meet the ESS Standards, including via NCESS or the SESSM where needed.
  - Coordinating and, where applicable, conducting tests of equipment (Commissioning Tests and Reserve Capacity Tests).
  - Conducting market settlement.
- Supporting market and power system development:
  - Contributing to the development and improving the effectiveness of the WEM through developing and supporting Rule Change Proposals.
  - Providing information and assistance to the Coordinator in the preparation of the WoSP.
  - Providing information and assistance to Network Operators in preparation of Transmission System Plans.
  - Advising and consulting with Network Operators in respect of System Operation Functions as contemplated under the Technical Rules for their Networks.
  - Developing and maintaining WEM Procedures relating to market operation, market administration, and system operation.
- Market monitoring and information provision:
  - Publishing market and power system information, including a Congestion Information Resource.
  - Supporting the Coordinator and the ERA in their roles of compliance monitoring, market surveillance, and market effectiveness monitoring, including monitoring Rule Participant compliance with certain WEM Rules obligations.
  - Managing and classifying the confidentiality status of Market Information for which it is the Information Manager.
  - Maintaining a DER Register.

AEMO is registered as a public company limited by guarantee. It is a not-for-profit organisation, with operating costs recovered through fees paid by Market Participants. AEMO's membership is split between government (60%, including the commonwealth government, the states, and the ACT) and industry (40%, including participants in the WEM and the National Electricity Market, which operates in the eastern states). A majority of the AEMO Board are independent directors who are accountable to the members. AEMO's compliance with the WEM Rules is independently audited each year.

3.4 The Economic Regulation Authority

The ERA is Western Australia's independent economic regulator. Its primary function in the WEM is to monitor Rule Participants' compliance with the WEM Rules, investigate potential breaches, and initiate enforcement action where appropriate.

The ERA has a range of enforcement actions available including issuing warnings, issuing Civil Penalties and applying to the Electricity Review Board for a range of orders.

The ERA's other functions are empowered under clause 2.2A.1 of the WEM Rules and include:

- Maintaining and developing WEM Procedures relating to market monitoring and compliance.
- Approving efficient costs for AEMO's operation and the resulting Market Fees.
- Defining guidelines and procedures for:
  - The content of AEMO budget proposals.
  - AEMO's regulatory reporting to the ERA and Market Participants.
  - Determining the Benchmark Reserve Capacity Price (BRCP) and the Market Price Limits.
  - Triggering the SESSM in case of inefficient market operation and monitoring AEMO's SESSM procurement activities.
  - Trading conduct and offer construction.
- Reviewing AEMO decisions on:
  - Setting Facility dispatch Tolerance Ranges.
  - Requiring Facilities to participate in the Outage planning process.
  - Rejecting Facility Outages.
- Providing independent oversight for specific market processes by conducting periodic reviews of:
  - The methodology used to determine the BRCP and the Market Price Limits.
  - The effectiveness and appropriateness of the methodologies used by Network Operators to develop Limit Advice, and by AEMO to develop Constraint Equations.
  - The economic impact of Network Operator Outages on the market.
  - The Relevant Level Methodology used to determine Reserve Capacity for Intermittent Generating Systems.
- Managing and classifying the confidentiality status of Market Information for which it is the Information Manager.

3.5 The Electricity Review Board

The Electricity Review Board is the primary appeals body for the WEM and has the following key functions:

- Considering applications from Rule Participants for review of a Reviewable or Procedural Decision:

  - Where a Rule Participant has been negatively impacted by a decision made by the Coordinator, AEMO or the ERA, it may apply to the Electricity Review Board for review of that decision.
  - For the purposes of review, the Electricity Review Board will exercise the same powers as the original decision maker and will determine whether the decision should be affirmed, set aside or varied.
  - Where the decision is a Procedural Decision, the Electricity Review Board is limited to considering whether the Coordinator, AEMO or the ERA followed the process outlined under the WEM Rules in making the relevant decision.
- Determining whether an order should be made against a Rule Participant for a breach of the WEM Rules:
  - Where the ERA considers that a Rule Participant has breached the WEM Rules, the ERA may to apply to the Electricity Review Board to make one or more orders in response to the breach;
  - If the Electricity Review Board determines the breach has occurred, the Board may make one or more orders, which can include suspending the Rule Participant's registration, disconnecting its Facilities and implementing a specified program for compliance.

3.6 The Market Advisory Committee

The Market Advisory Committee (MAC) is made up of industry representatives and is convened by the Coordinator. The MAC's functions are detailed in clause 2.3 of the WEM Rules.

The MAC advises the Coordinator on the development and evolution of the market and the WEM Rules, supports the Coordinator in monitoring the market, and advises the Coordinator, the ERA, AEMO, and Network Operators on WEM Rule and Procedure changes and general market operation issues.

The MAC must comprise the following members:

- The independent Chair (appointed by the Minister for Energy);
- Synergy (one member);
- Other Market Participants (at least six and not more than eight members);
- Contestable Customers (at least one and not more than two members);
- AEMO (two members);
- Network Operators (one or two members, one of whom must represent Western Power); and
- Independent members nominated by the Minister for Energy to represent small-use consumers (at least two).

MAC members are appointed by the Coordinator, in consultation with the independent Chair. The Minister for Energy and the ERA may both appoint Representatives to attend meetings of the Market Advisory Committee as observers.

3.6.1 MAC Working Groups

Where an issue to be addressed by the MAC is highly technical or specialised, the MAC may decide establish a Working Group of industry representatives to investigate and report back on the issue. Recent examples of Working Groups established by the MAC include:

- The WEM Investment Certainty Review Working Group;
- The Cost Allocation Review Working Group;
- The Demand Side Response Review Working Group; and
- The RCM Review Working Group.

3.7 Network Operators

Western Power is currently the only registered Network Operator in the SWIS. Core functions of Network Operators are set out in clause 2.2C of the WEM Rules and include:

- Maintaining and developing WEM Procedures relating to network access and connection.
- Providing information to AEMO (Loss Factors and Limit Advice) and to the Coordinator for the preparation of the WoSP.
- Developing and publishing an annual TSP and Network Opportunities Map.
- Managing the connection of new Facilities to its transmission network, including:
  - Reviewing, negotiating, approving, and maintaining registers and monitoring plans for GPS for connected and proposed Facilities.
  - Assessing and approving Commissioning Test Plans, procedures, and results.
  - Issuing and revoking Approval to Generate and Interim Approval to Generate Notifications for newly connected Facilities.
- Procuring NCESS from Market Participants where needed for network support.
- Providing metering data to AEMO as a Metering Data Agent.

4 Market administration

4.1 WEM Rules

The WEM Rules govern the operation of the SWIS and the electricity market therein, including the wholesale sale and purchase of electricity, Reserve Capacity, and ESS.

4.1.1 The Coordinator of Energy

A key function of the Coordinator is to administer and develop amendments to the WEM Rules. This includes administration of the Rule Change Process and Procedure Change Process.

The WEM Rules require the Coordinator to consult with the Market Advisory Committee when progressing Rule Change Proposals. Where the Coordinator chooses to not follow the Market Advisory Committee's advice, or only partially follows their advice, justification must be provided for doing so.

In consulting on a Rule Change Proposal, the Coordinator of Energy may also convene the MAC, meet with interested parties, procure technical advice, or establish a technical Working Group drawing on industry representatives if this is considered necessary to appropriately develop or evaluate changes.

Every three years, the Coordinator must arrange an independent review of the effectiveness of the Rule Change Process and Procedure Change Process.

The Coordinator formally reviews the overall effectiveness of the market every three years and provides a report to the Minister.

4.1.2 Rule Change Process[13]

There are no restrictions on who can propose a change to the WEM Rules. Any person may submit a Rule Change Proposal to the Coordinator using the form provided on the Coordinator's website.

A Rule Change Proposal will generally need to identify an issue in the WEM Rules and include proposed wording for new clauses, or amendments to existing clauses. Most importantly, the proposal must include an assessment of why the proposed Amending Rules will better enable the WEM objectives.

Upon receiving a Rule Change Proposal, the Coordinator will decide whether the proposal should be progressed and must publish notice of its decision. If the Coordinator considers the Rule Change Proposal to merit further investigation, then the proposal will be progressed under either the Fast Track or Standard Rule Change Process.

The Fast Track Rule Change Process may be used for rule changes that are urgently required, of a minor or procedural nature, or required to correct manifest errors. Under this process, the Coordinator undertakes a single round of consultation and the final decision must be published within 20 Business Days from the publication of the Coordinator's notice.[14]

[13] The Rule Change Process is detailed in clauses 2.4 to 2.8 of the WEM Rules.

[14] The Coordinator's notice is published in accordance with clause 2.5.7.

The Standard Rule Change process includes two rounds of formal consultation and will usually take around 19 weeks (provided none of the timeframes are extended). The second round involves consultation on a draft report published by the Coordinator prior to the publication of the Final Rule Change Report.

The Coordinator must assess the proposed Amending Rules against the WEM Objectives and other practical considerations outlined under clauses 2.4.2 and 2.4.3 of the WEM Rules. The Coordinator may choose to make additional amendments to the WEM Rules to implement the proposed changes and will consult on the need and form of any amendments.

At the conclusion of the Rule Change Process, the Coordinator's decision on whether to accept a Rule Change Proposal, and its reasons, will be published on the Coordinator's website, together with a time and date for when any Amending Rules will come into force.

The only appeals option for a rule change proponent is to apply to the Electricity Review Board for Procedural Review of the Coordinator's decision. This will only consider whether the Coordinator adhered to the Rule Change Process, it is not possible to dispute the merits of the decision by the Coordinator.

If a rule change relates to a Protected Provision,[15] the Coordinator must seek the Minister for Energy's approval. The decision of the Minister is not subject to appeal.

4.2 WEM Procedures[16]

The WEM Rules devolve certain methodological, process-related, and operational details to WEM Procedures. WEM Procedures contain more procedural and methodological detail than the WEM Rules and are amended more frequently than the WEM Rules.

- The Coordinator develops and changes WEM Procedures relating to administrative matters.
- AEMO develops and changes WEM Procedures that relate to market operations and power system operations.
- The Network Operator develops and maintains WEM Procedures relating to GPS, Limit Advice, and Determination of Loss Factors.
- The ERA develops and updates WEM Procedures relating to monitoring and compliance, Portfolio determination, the BRCP and monitoring the efficiency of RTM outcomes for FCESS.

AEMO, the Coordinator, the Network Operator, and the ERA (referred to as WEM Procedure owners) may propose changes to the WEM Procedures they are responsible for. Additionally, any Rule Participant can submit a Procedure Change Proposal to notify the relevant WEM Procedure owner that it considers a procedure change may be appropriate. Where the WEM Procedure owner determines to not progress a Procedure Change Proposal, it must publish the reasons.

WEM Procedure owners must publish all Procedure Change Proposals (including changes proposed by themselves) and request submissions from the public and may convene the Market Advisory Committee. The

[15] Examples of Protected Provisions include rules pertaining to governance, monitoring and enforcement arrangements, some information disclosure and publications requirements, some aspects of the RCM (such as some deadlines pertaining to the Reserve Capacity Cycle), supplementary capacity and certain Reserve Capacity Security provisions, and some aspects of settlement such as certain default provisions.

[16] The Procedure Change Process is detailed in clauses 2.9 to 2.11 of the WEM Rules.

issues addressed in the WEM Procedures can be quite technical and specialised, so the Market Advisory Committee may decide to nominate a Working Group to consider an issue or suggestion.

WEM Procedure owners must prepare a Procedure Change Report which includes the amended wording, feedback received on the change, together with a time and date for the new WEM Procedure to come into force.

4.3 Information management framework

Rule Participants, the Coordinator and the ERA need timely access to a wide range of market data to make efficient decisions. At the same time, providing Confidential Information in an unauthorised manner can have adverse commercial impacts on Rule Participants. Market Information produced or exchanged under the WEM Rules is managed according to the framework specified in Chapter 10. The intent of the framework is to make as much Market Information publicly available as is possible.

Market Information is managed by AEMO, Western Power (as Network Operator), the ERA, and the Coordinator (each being an Information Manager)[17]. Chapter 10 confers a range of responsibilities on Information Managers with regards to the management, disclosure, publication and retention of Market Information.

At the time at which Market Information is requested by a party, or otherwise required to be disclosed, Information Managers are responsible for classifying Market Information they are responsible for as either[18]:

- Public Information; or
- Confidential Information.

In classifying Market Information, an Information Manager must consider any assertions of confidentiality submitted by Rule Participants to whom the information relates. Market Information will generally be Public Information, unless its disclosure could result in adverse commercial or power system impacts.

Rule Participants may request both Public Information and Confidential Information from the relevant Information Manager. Most Public Information should be available via the relevant Information Manager's website; however, if it is not, the Information Manager must make the Market Information available at no cost to any person on application.

Where Confidential Information is requested, the requesting party must provide specific justifications to support the request, and the relevant Information Manager may only disclose it under circumstances, including:

- With the permission of any Market Participants to whom the information pertains; or
- If disclosure is required by law or a judicial body; or
- If disclosure is required to ensure the safety of personnel or the power system; or
- The requesting party is either the ERA, the Coordinator or the Network Operator (and the information is required to fulfill the Network Operator's functions under the WEM Rules or Procedures); or
- The benefit of disclosing the information to electricity consumers outweighs any commercial detriment to Rule Participants.

[17] An Information Manager is responsible for any information they are required to publish under the WEM Rules; or where a publication requirement does not exist, for any information they are required to produce under the WEM Rules. If the information is neither published nor produced, then the Information Manager is the party who receives that information.

[18] Chapter 10 contains some provisions for Rule Participants to dispute the classification of Market Information which relates to them.

Depending on the nature of the Market Information and the request, the Information Manager's assessment of the confidentiality status of the information, and/or its decision on whether to disclose the information may be subject to dispute. Dispute resolution proceedings are undertaken by the Coordinator, with appropriate engagement with relevant parties to the dispute.

The framework applies only to 'direct' Market Information, that is information produced or exchanged in accordance with the WEM Rules or WEM Procedures. It does not apply to information or documents that are not required under the Rules or Procedures, such as Bilateral Contracts between participants and residential electricity bills.

4.4 Monitoring and enforcement of the WEM Rules[19]

The ERA monitors the compliance of Rule Participants with the WEM Rules and WEM Procedures, which includes monitoring for inappropriate or anomalous trading behaviour.

The ERA is required to publish a Monitoring Protocol WEM Procedure,[20] which sets how the ERA will monitor and investigate Rule Participants compliance and its approach to enforcement.

AEMO supports the ERA in its monitoring role by monitoring compliance with a specified range of obligations and reporting any breaches to the ERA. This includes by monitoring Market Participants' compliance with their dispatch obligations

Rule Participants must self-report breaches of the WEM Rules and WEM Procedures to the ERA, and can also inform the ERA where it considers another Rule Participant has breached the WEM Rules or a Procedure (including AEMO and the Network Operator).

When the ERA becomes aware of an alleged rule breach by a Rule Participant, it records the breach, notifies and consults with the breaching Rule Participant, and commences its investigation in accordance with the risk rating assigned to the alleged breach.

Where the ERA determines that a breach of the WEM Rules or WEM Procedures has occurred,[21] the ERA may undertake one of the following enforcement actions:

- Issuing a warning to a Rule Participant to rectify the contravention within a specified timeframe;
- Issuing a Civil Penalty notice where the breach involves a Civil Penalty provision. In accordance with Schedule 1 of the WEM Regulations, a Civil Penalty can be one of the following categories:
  - Category A Civil Penalties for less serious offences, such as failure to provide information when required to provide that information.
  - Categories B and C for more serious rule breaches, such as those with an impact on power system security reliability or involving the abuse of market power.
- Bringing an application to the Electricity Review Board for an order under the WEM Regulations. These are likely to involve very serious offences, which may require actions such as temporary or permanent Rule Participant de-registration or Facility disconnections.

[19] Clauses 2.13 to 2.16 set out the compliance monitoring and enforcement process.

[20] Clause 2.15.3 sets out the matters that must be specified in the ERA's Monitoring Protocol.

[21] This determination must be done in accordance with clause 2.13.27(d).

Market Power Mitigation

The ERA monitors Market Participant offers in the STEM and RTM to detect the potential exercise of market power.[22] In both these markets, Market Participants must ensure that their offer prices reflect the costs that a Market Participant without market power would include in a profit maximising offer.[23] The ERA publishes an Offer Construction Guideline and Trading Conduct Guideline to assist Market Participants to develop compliant offers.

4.5 Reviewable Decisions and disputes[24]

Under the WEM Regulations, certain decisions made by AEMO, the ERA, the Coordinator, and Network Operators are designated as Reviewable Decisions. The Reviewable Decision process applies to certain areas in the WEM Rules where these parties have some discretion in decisions that have a significant impact on Rule Participants. Some of these decisions are subject to a merits review, others to a Procedural Review. If a Rule Participant wants to appeal a Reviewable Decision, it can apply to the Electricity Review Board to have the decision reviewed. Any determination reached by the Electricity Review Board will not be subject to appeal, except to the Courts on questions of law.

The dispute resolution process covers disputes between Rule Participants but does not apply to Reviewable Decisions or certain aspects of compliance with GPS under the WEM Rules. The dispute resolution process sets out two stages to be followed. Under the first stage, the Rule Participants attempt to resolve disputes between themselves. A Rule Participant may send a Notice of Dispute to another Rule Participant (which may include AEMO), and the parties to the dispute must make reasonable endeavours to meet on one or more occasions, as necessary. If they fail to resolve a dispute between themselves within a period agreed by all the parties, or 60 days if there was no agreed timeframe, then the dispute must move to the second stage and the parties to the dispute must consider using independent mediation and/or arbitration to resolve the dispute. Finally, the parties may resort to litigation or other court processes.

4.6 Budgets and fees[25]

Costs incurred by AEMO, the ERA, and the Coordinator in the operation and administration of the WEM are recovered from Market Participants through Market Fees and one-off fees (for applications and re-assessments).

AEMO's costs — or Allowable Revenue — are regulated by the ERA. The Allowable Revenue represents a medium-term view of AEMO's operational costs. The ERA determines the Allowable Revenue of AEMO every three years for the subsequent three year period. AEMO can also apply to the ERA during the current Review Period for additional costs to be considered as part of an in-period adjustment. Every year AEMO submits a budget to the ERA, which must be consistent with the Allowable Revenue determination.

[22] Clauses 2.16A to 2.16E set out how the ERA monitors the market for anomalous behaviour and Market Participant obligations with respect to Trading Conduct.

[23] Market Participants must have reasonable grounds and evidence to support the rationale for their offer contents.

[24] Reviewable Decisions and the dispute resolution mechanism is set out in clauses 2.17 to 2.20 of the WEM Rules.

[25] The Budget and fees process including Market Fees is described in clauses 2.22A to 2.25 of the WEM Rules.

AEMO recovers its budgeted costs, the portion of the ERA's budget relating to WEM activities, and the portion of the Coordinator's budget relating to WEM activities through a 'per MWh' Market Fee rate applied to metered generation and consumption of Market Participants.

AEMO can also recover one-off costs incurred when processing applications (for example, registration or fulfilling a request for Market Information) or reassessment of Certified Reserve Capacity (CRC).

4.7 Market Price Limits[26]

4.7.1 Benchmark Reserve Capacity Price

Each year, the ERA determines the BRCP to establish a reference for the cost of providing additional Reserve Capacity. The BRCP is calculated by undertaking a technical bottom-up cost evaluation of the entry of a 160 MW open-cycle gas turbine (OCGT) generation Facility in the SWIS for the relevant Capacity Year.

The BRCP is used to calculate the capacity prices applicable to each Facility (see Section 7.6) and is described in further detail in Section 4.16 of the WEM Rules and the BRCP WEM Procedure.

4.7.2 Energy Offer Price Ceiling

Every three years, the ERA reviews and determines maximum offer price limits for the STEM and RTM under section 2.26 of the WEM Rules[27]. These function as a cap on prices when there is a shortage and are also used to restrict Market Participant offer prices.

The offer cap is based on the ERA's estimate of the short run marginal cost of the most expensive Facility in the SWIS generation fleet. The offer cap incorporates a risk-margin or uncertainty measure associated with ERA's short-run marginal cost estimate.

Energy offers in the STEM and RTM cannot exceed the Energy Offer Price Ceiling.

4.7.3 Energy Offer Price Floor

Every three years, the ERA reviews and resets (if required) minimum offer price limits for the STEM and RTM under section 2.26 of the WEM Rules. The Energy Offer Price Floor is used to restrict Market Participant offer prices, and also provides a floor for market prices in times of extreme system conditions like low demand (when Market Participants would prefer to pay to inject energy rather than shut down a Facility).

The Energy Offer Price Floor is set based on the principles that it should:

- Be low enough that the market clears above it in almost all circumstances;
- Limit exposure to prices that threaten the viability of a prudent Market Participant; and
- Be set at a level that would incentivise a Facility with high cycling costs to decommit in a low load situation.

Energy offers in the STEM and RTM must be above the Energy Offer Price Floor.

[26] Offer price floors and ceilings are detailed further in clause 2.27 of the WEM Rules.

[27] While the Energy Offer Price Ceiling is reviewed every three years, the ERA may allow the cap to be indexed outside of the Review Period to reflect shorter-term changes to input costs (e.g. fuel cost variability).

4.7.4 FCESS Price Ceilings

Every three years[28], the ERA reviews and determines maximum FCESS price limits for the RTM under section 2.26 of the WEM Rules. These are used to restrict Market Participant offer prices[29].

The ERA determines an Offer Price Ceiling for each FCESS traded in the WEM. The cap is based on the ERA's estimate[30] of the variable costs of the Facility with the highest relevant FCESS cost, where those variable costs cannot be recovered through other WEM mechanisms (e.g. Energy Market Clearing Prices or through the FCESS Uplift Payment mechanism (see Section 10.4.2)).

[28] While the FCESS Offer Price Ceilings are reviewed every three years, the ERA may allow the cap to be indexed outside of the Review Period to reflect shorter-term changes to input costs (e.g. fuel cost variability).

[29] The FCESS and Energy Offer Price Ceilings work together to limit the maximum FCESS Market Clearing Price. However, if there is a shortfall in FCESS, clause 7.11A.1(i) allows AEMO to set the relevant FCESS Market Clearing Price to the difference between the Energy Offer Price Ceiling and the Energy Offer Price Floor.

[30] The ERA estimate must be consistent with the Offer Construction Guidelines it publishes under clause 2.16D.1 of the WEM Rules (see also Section 3.4).

5 Participation and registration

Anyone wishing to participate in the WEM must follow the processes set out in the WEM Rules to ensure they and their Facilities are properly registered with AEMO. Facilities above a certain size must follow the Network Operator's connection processes to gain connection to the SWIS and must be registered with AEMO for participation in Market Scheduling and dispatch processes.

5.1 Network access and Facility connection

To connect to the SWIS, a transmission-connected Facility must have an access arrangement with the Network Operator demonstrating compliance with all relevant Technical Rule requirements and agreed GPS that will apply to Facility operation[31,32]. The purpose of the access process is to ensure that a Facility meets the Technical Requirements of the Network, giving AEMO and the Network Operator confidence that connecting the Facility will not increase risk to PSS and the Facility will be able to operate through expected divergences in system conditions.

New Facilities provide a generation system model, which AEMO and the Network Operator will use for:

- Load Flow and Contingency analysis.
- Harmonic analysis.
- Transient Stability and Electromagnetic transient analysis.

Power system modelling consists of a computer rendition of the Facility and its connection to the Network, detailing the characteristics and parameters of individual generating units, and other components such as reactive power devices, energy storage devices, and control system parameters. It is critical to accurately incorporate into the model not only the various devices but also their parameters. Once the model has been developed, it is possible to analyse what is happening or might happen in the real power system.

The proponent also submits proposed GPS for its transmission-connected Facility, covering:

- Active and reactive power capability and temperature dependence.
- Active power, reactive power, voltage, Inertia, and frequency control.
- Quality of electricity supplied.
- Ride-through capability for frequency, voltage, load rejection, and quality of supply disturbances.
- Generation protection, remote monitoring, remote control, and communication system capabilities.

Facility performance must at least meet the Minimum Performance Standard specified in each category. If performance will be at or better than the specified Ideal Performance Standard, no negotiation is required. If the

[31] The Technical Requirements of distribution-connected Facilities are governed by the Technical Rules, which, unlike the GPS, are not a negotiated framework.

[32] The connection process is governed by the Electricity Networks Access Code, while the GPS requirements are governed by the WEM Rules. The process for approving the GPS of new Facilities and the compliance enforcement process is covered in Chapter 3A of the WEM Rules. Appendix 12 of the WEM Rules details the standards that Facilities must meet.

Proposed Generator Performance Standard is less than the Ideal Performance Standard in any area, acceptance is subject to negotiation with the Network Operator and AEMO.

At the end of the process, the Facility will be issued with an Approval to Generate. From that point on, the Facility must comply with the approved GPS and must monitor its own compliance according to an AEMO-approved Generator Monitoring Plan (which must be based on principles set out in AEMO's GPS WEM Procedure). In the event of non-compliance, the participant must notify AEMO immediately and propose a Rectification Plan. When a participant self-notifies and corrects the issue as per their Rectification Plan, they are not subject to non-compliance penalties from the ERA[33].

5.2 Rule Participant and Facility registration

5.2.1 Rule Participant classes

WEM Rules confer obligations on entities (Rule Participants and unregistered entities) which fall into three classes:

- **Network Operator** – Rule Participant registration is required for Network Operators only if AEMO requires information about the relevant Network to ensure PSS and PSR.
- **Market Participant** – Market Participants can be:
  - Entities that own, operate or control Facilities containing Energy Producing Systems and/or Loads which will be used to provide WEM services[34]. Rule Participant registration is mandatory where an Energy Producing System is above a certain size (see Section 5.2.4). Where Rule Participant registration is not required because the systems are smaller than the registration threshold, entities can register optionally.
  - Entities that serve end-use customers (retailers), and purchase WEM services to serve their customers. Rule Participant registration is mandatory.
- **AEMO**.

The WEM Rules also set out obligations for the ERA and the Coordinator. These entities are not Rule Participants.

5.2.2 Definition of a Facility

A Facility is a collection of one or more Facility Technology types. The Facility Technology Types are:

- A **distribution system** – not further defined in the WEM Rules, but understood to relate to a low voltage Network.
- A **transmission system** – not further defined in the WEM Rules, but understood to relate to a high voltage Network.
- An **Intermittent Generating System** – an electricity producing system whose:

[33] The Network Operator can exempt participant from compliance with GPS if costs would outweigh the benefits. However, the exempted Facility would still be subject to the requirements set out in the Technical Rules.

[34] WEM services refer to the provision of energy, Reserve Capacity and ESS through the various trading mechanisms described in Section 2.2.

  - Output is not reasonably controllable; and
  - Output is dependent on a fuel resource that cannot be directly stored or stockpiled; and
  - Availability is difficult to predict.
- A **Non-Intermittent Generating System** – an electricity producing system that is not intermittent.
- An **Electric Storage Resource** – a system capable of receiving and storing energy for later production of electricity. This includes all forms of storage, including batteries, compressed air, pumped hydro, etc.
- A **Load** – one or more electricity consuming resources or devices (excl. Electric Storage Resources) located behind a single network connection point, or electrically connected behind two or more shared network connection points.

Examples of Facilities:

A Facility that consumes or produces electricity can be interpreted as a collection of Facility Technology Types connected behind a single network connection, or electrically connected behind two or more shared network connection points. For example:

- A Non-Intermittent Generating System like a CCGT at a single network connection point.
- An Intermittent Generating System like wind turbines and/or solar systems electrically connected behind two shared network connection points.
- A hybrid system comprising an Intermittent Generating System and an Electric Storage Resource at a network connection point.
- Multiple Loads at a network connection point.

A Facility which is a collection of Facility Technology Types connected behind a single network connection, can be also collected into an Aggregated Facility (see section 5.3).

A distribution system is a Facility in its own right, as is a transmission system.

Some Facilities must be registered while others do not require registration (see section 5.2.4). An unregistered Facility will still be metered and will be included in settlement processes as a Non-Dispatchable Load.

Three special types of Facility are only designated as Facilities if they are registered:

- A **Small Aggregation** is a collection of distribution connected technologies at a single Electrical Location[35]. This type of Facility is intended to allow aggregated DER to participate in the WEM without triggering the formal aggregation process. Further changes to the registration taxonomy may follow to enable DER participation.
- An **Interruptible Load** is a collection of Non-Dispatchable Loads that provides Contingency Reserve Raise ESS.

[35] The Electrical Location of a Facility denotes the transmission zone substation at which the Facility's Transmission Loss Factor is defined. Hence, Facilities with the same Electrical Location would have the same Transmission Loss Factor.

- A **DSP** is a collection of Non-Dispatchable Loads that can be curtailed on request by AEMO and is compensated by Reserve Capacity payments.

The System Size of a person's Facility comprising their Energy Producing System is the key factor in mandatory Rule Participant and Facility Registration requirements (discussed in more detail in section 5.4.2).

5.2.3 Facility Classes

Facilities can be registered in one of the following classes:

- Network.
- Scheduled Facility.
- Semi-Scheduled Facility.
- Non-Scheduled Facility.
- Interruptible Load.
- Demand Side Programme.

Section 5.2.4 summarises registration requirements and the rules that determine which Rule Participant and Facility Classes apply to different persons and Facilities, respectively.

5.2.4 Rule Participant and Facility registration requirements

Networks

Network owners are required to register in the Network Operator class if:

- AEMO requires information from the Network Operator's Network to ensure PSS and PSR (clause 2.28.3(a)); and
- if Registered Facilities are directly connected to that Network (clause 2.28.3(b)).

Network Operators who have been mandated to register must register their relevant Networks in the Network Facility Class.

Western Power is currently the only registered Network Operator; and has two Registered Facilities: one for its transmission system and one for its distribution system.

Facilities containing Energy Producing Systems

Rule Participant and Facility registration can be mandatory or voluntary; it is generally the System Size of a Facility comprising an Energy Producing System that triggers the mandatory requirement to register, but registration is also mandatory for small systems (under 10MW; see also Table 1) which can affect PSS and PSR.

The System Size of a Facility with no Electric Storage Resources is the lesser of its Declared Sent Out Capacity (DSOC) and the total MW output capability of all Energy Producing Systems comprising the Facility; the latter is measured by the nameplate rating of the relevant Energy Producing System.

The System Size of a Facility that contains an Electric Storage Resource takes into account the maximum single cycle change of the storage components, and is the sum of:

- The lesser of its DSOC and total combined MW output capability of all Energy Producing Systems comprising the Facility, and
- The lesser of its Contracted Maximum Demand and the total consumption capability of all Electric Storage Resources comprising the Facility.

Aggregated DER is subject to the same System Size calculation as other Facilities, but a different calculation may be considered as DER participation increases[36].

Figure 2 illustrates how the System Size of a hybrid Facility comprising wind turbines (Intermittent Generating Systems) and batteries (Electric Storage Resources) would be calculated.

Figure 2 System Size of Facility comprising wind and battery hybrid

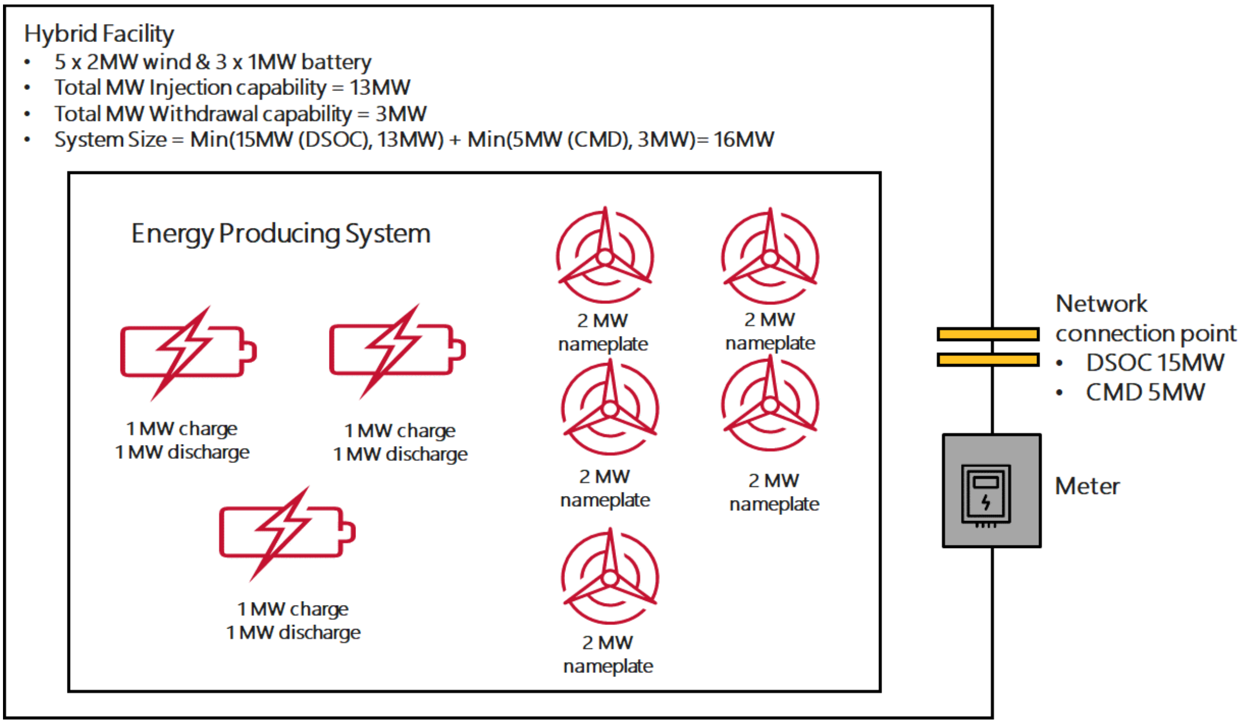


Table 1 summarises the registration requirements for Market Participants and their Facilities comprising Energy Producing Systems.

Table 1 Rule Participant and Facility registration requirements

Facility System Size	Registration requirements
10 MW or greater	Unregistered entity must register in the Market Participant class and must register its Facility.
5 MW or greater but less than 10 MW	Unregistered entity must apply to AEMO for exemption from Rule Participant and Facility registration. If exemption is not granted, the entity must register in the Market Participant class and register its Facility. AEMO can revoke exemption if Facility must be registered for PSS and PSR purposes. Entity may optionally register as a Market Participant and register its Facility if it wishes to provide WEM services.

[36] The System Size of a Facility comprising DER must take into account the behaviour of the uncontrollable Load component to ensure its impact on the power system is quantified correctly. At this stage, the System Size calculation makes no allowance for the uncontrollable Load component; future rule changes may refine the System Size definition further to account for behind-the-meter Load.

Facility System Size	Registration requirements
Less than 5 MW	Unregistered entity has a standing exemption from AEMO from Rule Participant and Facility registration. AEMO can revoke exemption if Facility must be registered for PSS and PSR purposes. Entity may optionally register as a Market Participant and register its Facility if it wishes to provide WEM services.

Facilities comprising Energy Producing Systems can be registered in one of three Facility Classes, as summarised in Table 2.

Table 2 Facility Classes for Facilities comprising Energy Producing Systems

Facility Class	Registration requirements
Scheduled Facility	Must be fully controllable such that it can comply with a Dispatch Target to maintain its Injection or Withdrawal for a specified period (e.g., Facilities comprising Electric Storage Resources only, Non-Intermittent Generating Systems such as thermal plants, or hybrid systems comprising Non-Intermittent Generating Systems and Electric Storage Resources). A Facility containing an Energy Producing System which is deemed to be fully controllable by AEMO must be registered in the Scheduled Facility Class.
Semi-Scheduled Facility	Must be partially controllable so that it can curtail upon request from AEMO, i.e. it can comply with a Dispatch Cap (e.g. Facilities comprising Intermittent Generating Systems such as wind or solar, or hybrid systems comprising Intermittent Generating Systems and Electric Storage Resources).
Non-Scheduled Facility	Not required to comply with Dispatch Targets or Dispatch Caps but must respond to Directions during system emergencies. Only Facilities with a System Size below 10 MW can be registered in this category. Under certain circumstances (relating to PSS and PSR), AEMO may enforce registration in the Scheduled Facility or Semi-Scheduled Facility Classes for Facilities <10 MW which could otherwise have registered as a Non-Scheduled Facility.

Facilities containing Loads

A Facility may also comprise one or more Loads, which are electricity consuming resources. The participation model for Facilities comprising Loads is summarised in Table 3.

Note that an unregistered Facility comprising one or more uncontrollable Loads (for example, commercial and industrial Loads and households) is a Non-Dispatchable Load. As it is unregistered, it does not belong to any Facility Class; however, the person owning, operating, or controlling the Load or the retailer serving the Load must be registered in the Market Participant class (so the consumption of the Load can be attributed to them as part of settlement). A Non-Dispatchable Load can be associated with a Registered Facility of type DSP or Interruptible Load.

Table 3 Rule Participant and Facility registration requirements for Facilities comprising Loads

Facility Class	Description
Scheduled Facility	A Facility containing one or more Loads that is fully controllable and able to respond to Dispatch Instructions by increasing and decreasing its Withdrawal can register in the Scheduled Facility Class.
Interruptible Load	A Facility comprising one or more Non-Dispatchable Loads that can be interrupted in response to a frequency signal to provide Contingency Reserve Raise ESS. The Facility must be registered in the Interruptible Load Facility Class and can associate one or more Non-Dispatchable Loads (‘Associated Loads’) to its Facility if they are in the same Electrical Location. The person owning, operating, or controlling the Interruptible Load (whether directly or contractually) must be registered as a Market Participant. The Market Participant that is financially responsible for the Non-Dispatchable Load (with respect to energy volumes) can be different to the Market Participant to whom the Interruptible Load is registered. This allows for third party aggregators to associate a Non-

Facility Class	Description
	Dispatchable Load with an Interruptible Load provided they have an agreement with the party operating or controlling the Load. Interruptible Loads are compensated solely via ESS payments, which are paid to the Market Participant who has registered the Interruptible Load. Energy consumed by the associated Non-Dispatchable Loads is settled by the participant financially responsible for that Non-Dispatchable Load.
Demand Side Programme	A Facility comprising one or more Non-Dispatchable Loads that can be curtailed on request by AEMO. The Facility must be registered in the DSP Facility Class and can associate one or more Non-Dispatchable Loads ('Associated Loads') to its Facility, as long as they are in the same Electrical Location. The person owning, operating, or controlling the DSP must be registered as a Market Participant. The Market Participant associated with the Non-Dispatchable Load can be different to the Market Participant to whom the DSP is registered. This allows for third party aggregators to associate a Non-Dispatchable Load with a DSP provided they have an agreement with the party operating or controlling the Load. When curtailed, the Facility does not receive a payment from the market; its curtailed consumption is settled at the prevailing Reference Trading Price. DSPs are solely compensated via Reserve Capacity payments. Energy consumed by the associated Non-Dispatchable Loads is settled by the participant financially responsible for that Non-Dispatchable Load.

Intermittent Loads[37]

An Intermittent Load is a Load that is normally fully supplied by an embedded generator at the same site as the Load without requiring any electricity to be supplied from a Network registered with AEMO. It only requires electricity from the Network intermittently when its embedded generator is not fully operational. It is always part of a Facility — either part of a Registered Facility, or part of an unregistered Non-Dispatchable Load.

There are currently six Intermittent Loads participating in the WEM. These Loads have been grandfathered under the new market arrangements, with special Metered Schedule calculations that reduce their exposure to funding Reserve Capacity for the portion of Load served by embedded generation. Existing registered generation systems serving the grandfathered Intermittent Loads will be transitioned to the relevant new Facility Class, and Participants may register a grandfathered Facility as a Non-Scheduled Facility even where it would otherwise be required to register as a Scheduled Facility or a Semi-Scheduled Facility. These special arrangements will be removed if the Facility increases the size (maximum Withdrawal) of the Intermittent Load by more than 10 MW.

Participants wishing to register new Facilities which comprise an Energy Producing System and a co-located Load can still register as an Intermittent Load; however, they would not be able to avail themselves of the specialised funding arrangements for Reserve Capacity.

All Intermittent Loads (both new and existing) must provide AEMO with data about the Facility, including:

- Information about the embedded generator (including capacity, temperature dependence, and fuel source).
- Information about the site (including DSOC, CMD, protection schemes, and a single line diagram).
- As-generated energy measurements for each component of the embedded generator.
- A Nominated Excess Capacity, representing the maximum instantaneous MW Injection expected from the Facility.

[37] The registration rules pertaining to Intermittent Loads are covered by clause 2.30B of the WEM Rules.

Registration decisions for Facilities without Intermittent Loads are driven by the System Size of the Facility. For Facilities containing Intermittent Loads, the Nominated Excess Capacity is used instead. A Facility is allowed to exceed its Nominated Excess Capacity in 120 Dispatch Intervals per year (10 hours). Once the 120-interval threshold is breached, the participant must update its Nominated Excess Capacity, potentially triggering additional registration requirements.

5.2.5 Facility Class assessments

When a new Facility participates in the RCM, its final operational characteristics will not yet be known, but if it is to be allocated CRC, it needs to have a Facility Class. When a person first expresses interest in Capacity Credits for a new Facility, AEMO will request sufficient information to identify the Facility Technology Types expected to be installed and assign an Indicative Facility Class to the Facility. A Facility Class assigned to an unregistered Facility, or a Facility Upgrade will be used in all activities that occur in Year 1 of a Reserve Capacity Cycle until the Facility becomes a Registered Facility or the Facility Upgrade commences operation.

The Facility Class of a Facility is not necessarily fixed. If the operational characteristics change, it can be assigned to another Facility Class. For example:

- If an 8 MW wind farm installs another 5 MW of wind capacity, it will move from the Non-Scheduled Facility Class to the Semi-Scheduled Facility Class.
- If a Semi-Scheduled Facility installs a large onsite battery that means it can now be confident of its output, it will move into the Scheduled Facility Class.

A Market Participant can request AEMO to reassess the Facility Class of a Facility, and AEMO can review classification at any time.

5.3 Facility aggregation[38]

Participants may apply to aggregate two or more single Facilities into an Aggregated Facility for the purposes of participation in the WEM. Such requests will only be approved by AEMO if:

- The aggregation does not have any adverse impact on AEMO's ability to implement locational dispatch; hence, AEMO can reject an application if the relevant Facilities are not located at a single Electrical Location.
- The aggregation does not have an adverse impact on AEMO's ability to procure Contingency Reserve Raise ESS or dispatch FCESS.
- The aggregation does not comprise Facilities with different Facility Monthly Reserve Capacity Prices (thereby impeding financial settlement of RCM services).
- The aggregation does not adversely impact on PSS and PSR.
- The participant can provide AEMO with Standing Data for individual Facilities, and for the aggregation as required.

[38] The Facility aggregation process is described in clause 2.30A of the WEM Rules.

The framework for DER participation in the WEM is currently under review by EPWA. This section will be revised in a future release as more information becomes available.

Small Aggregations are classed as a Facility type comprising distribution connected devices at a single Electrical Location. These Facilities have a different aggregation process as they are smaller and less likely to impact PSS and PSR.

5.4 Registration process

Individuals wanting to register themselves and their Facilities must apply to AEMO and undergo a registration process[39].

5.4.1 Rule Participant registration

To register as a Rule Participant, the relevant person must:

- Be resident in, or have a permanent establishment, in Australia.
- Be registered for Australian GST.
- Not be a Chapter 5 body corporate under the Corporations Act 2001, or under a similar form of administration under any laws applicable to it in any jurisdiction.
- Not be immune from suit in respect of the obligations of the Rule Participant under these Market Rules.
- Be capable of being sued in its own name in a court in Australia.

Further details about the Rule Participant registration process can be found in the registration WEM Procedures, including timelines and information requirements[40].

5.4.2 Facility registration

The registration process for a Facility involves providing information (including but not limited to Standing Data) on the Facility that enables AEMO to determine whether the Facility satisfies the criteria for being registered, including enabling AEMO to assign a Facility Class based on its controllability. The registration information is used by AEMO to facilitate power system operations, trading and market operations and administration.

A Market Participant must make arrangements at its Facility for the relevant communication and control systems and market systems requirements before AEMO can approve the registration.

Further details about the Facility registration process can be found in the relevant WEM Procedure, including timelines and information requirements.

[39] The registration process is described in clause 2.31 of the WEM Rules.

[40] See AEMO | WEM Procedures.

5.4.3 Standing Data

Rule Participants must submit Standing Data to AEMO to complete the registration process[41].

Standing Data is static data pertaining to a participant's Facility.

Examples of Standing Data that participants must submit in respect of Facilities containing Energy Producing Systems include ramp rates, minimum generating levels, and temperature dependence curves. Standing Data requirements may vary depending on the products that the specific Facility is providing. For example, only Facilities providing FCESS need to have Standing Data for static Enablement Minimum and Enablement Maximum levels

Market Participants serving customers at Non-Dispatchable Loads must also provide certain data pertaining to the connection points at which those Loads are connected.

Market Participants must ensure that their Standing Data is correct, and must update Standing Data if it becomes outdated, of if the participant becomes aware of an error.

Unregistered Facilities are not required to provide Standing Data, but AEMO will sometimes seek information on an unregistered Facility (under clause 2.34.11 or clause 2.34.12B), especially where needed to monitor exemption from registration[42].

5.5 Facility commissioning

AEMO requires a Facility to undergo Commissioning Tests to, among other things:

- Test the control, monitoring, and communication systems for a Facility (when the Facility is nearing completion).
- Test a Facility after it has undergone significant maintenance.
- Demonstrate compliance with GPS.
- Demonstrate ability to be accredited under the ESS accreditation process (see below).

Facilities (including Non-Scheduled Facilities) undergoing commissioning must have their Commissioning Test Plan approved by AEMO, and must comply with AEMO's Dispatch Instructions[43] when carrying out the Commissioning Test.

5.6 Facility accreditation for ESS

Before a Facility can participate in the RTM to provide one or more FCESS, AEMO must confirm the Facility's capability to provide that service, a process called 'accreditation'.

Participants can seek ESS accreditation as part of the Facility commissioning process, or at any time thereafter.

[41] The process for maintaining Standing Data is set out in clause 2.34 of the WEM Rules. Appendix 1 of the WEM Rules details what type of Standing Data is required from different types of Facilities.

[42] Also, exempted persons must provide notice of changes under clause 2.28.9A, and AEMO may place conditions on exemptions to provide information under clause 2.28.16, 2.28.16B or 2.29.4M.

[43] Dispatch Instructions include quantities for energy and FCESS dispatch.

AEMO can re-assess accreditation at any time if it deems that the performance of a Facility is varying significantly from its accredited parameters. Participants can also request reassessment. If less than 12 months has passed since the Facility's last accreditation, then AEMO may decline the reassessment; otherwise AEMO must re-assess.

The accreditation process varies depending on the service being assessed, but all cases involve testing Facility response in different system conditions[44].

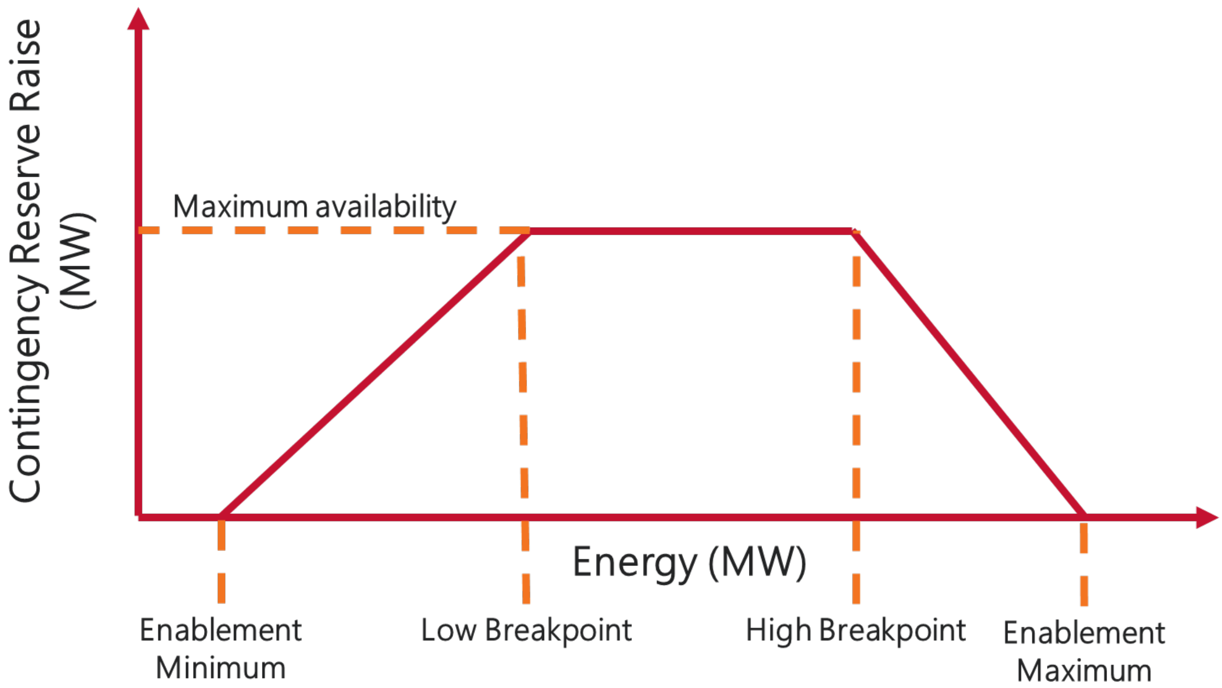
5.6.1 FCESS trapezium

Key parameters of a Facility's capability to provide a FCESS include:

- The maximum quantity of the service which it can provide.
- The highest and lowest levels of energy production or consumption at which it can provide the maximum quantity of the service (High Breakpoint and Low Breakpoint).
- The highest and lowest levels of energy production or consumption at which it can provide any quantity of the service (Enablement Maximum and Enablement Minimum).

These parameters define the feasible Operating Zone to be used in the Dispatch Algorithm, known as the 'FCESS trapezium'. Each Facility will have a trapezium for each accredited FCESS. Figure 3 shows an example trapezium for Contingency Reserve Raise. A trapezium for RCS is likely to be closer to a rectangle.

Figure 3 Example FCESS trapezium



[44] The ESS accreditation process is detailed further in clause 2.34A of the WEM Rules.

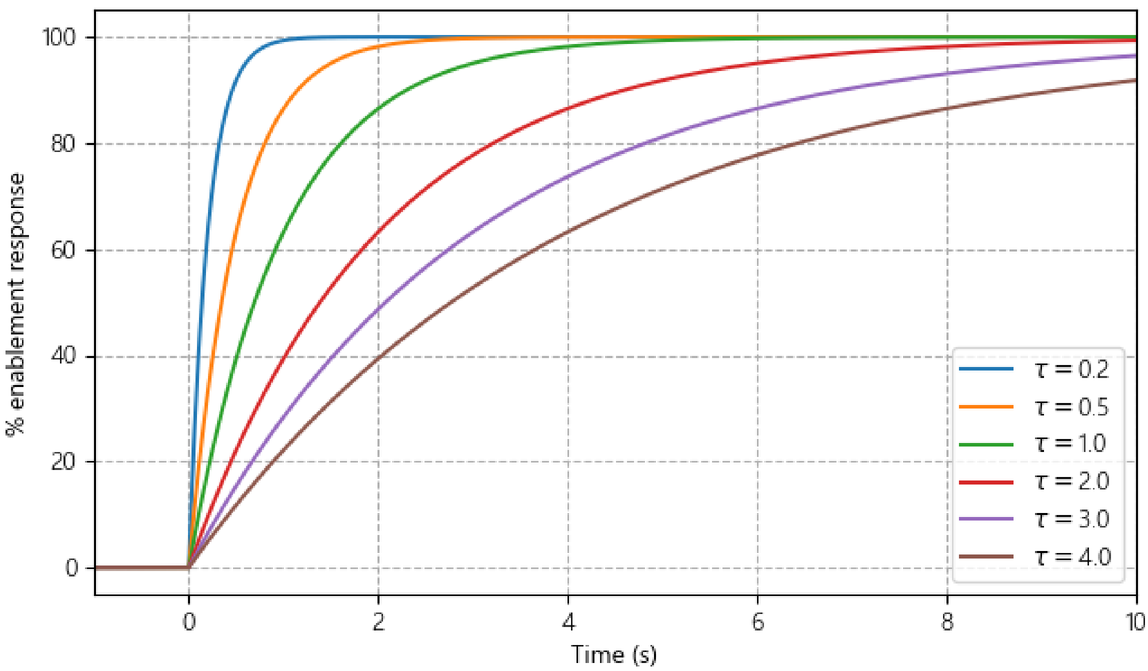
5.6.2 Facility Speed Factors

For Facilities providing Contingency Reserve, accreditation test results will be used to determine a 'Facility Speed Factor' which reflects the characteristics of a Facility's response to frequency deviation, and the profile in time with which its response is provided. Figure 4 shows an example of how various response curves map to different Facility Speed Factors, using Equation 1, where PFR is the Primary Frequency Response from the Facility, e is the mathematical constant Euler's number, t is the time in seconds, and τ is the Facility Speed Factor.

Equation 1: Facility Speed Factor curve

$$PFR \times (1 - e^{-t/\tau})$$

Figure 4 Example translation of response curves to Facility Speed factors



A Facility that can provide full response within a fraction of a second might have $\tau = 0.2$, while a Facility that takes several seconds to fully respond might have $\tau = 4$.

The Facility Speed Factor is incorporated into the Dispatch Algorithm to reflect the fact that slower-responding Facilities may contribute less than others to the provision of an ESS in some system conditions.

5.7 Prudential requirements

Market Participants are subject to prudential requirements as a fundamental requirement for participation in the market. They must post Credit Support with AEMO which must at least equal their Credit Limit; with Credit Limit being the maximum net dollar amount that the Market Participant is likely to owe AEMO within the maximum 35-day period between the start of a Trading Week and the date when transactions for that Trading Week are settled.

A Market Participant's Trading Limit is a prudential factor multiplied by its Credit Limit. The prudential factor is 0.87, which has been calculated by taking a ratio of the number of days before a Margin Call is issued to the maximum number of subsequent days before a participant would be suspended for non-payment[45].

AEMO monitors Market Participants' Outstanding Amounts daily. The Outstanding Amount indicates the net amount payable by the Market Participant to AEMO at a given point in time (accounting for any voluntary prepayments and amounts owing from previously settled Trading Weeks). The Outstanding Amount is an indicator of a Market Participant's exposure and enables AEMO to determine whether it holds enough Credit Support to cover a default by the Market Participant.

If a Market Participant's Outstanding Amount exceeds its Trading Limit, AEMO may issue a Margin Call, which the Market Participant must address by posting additional Credit Support. Failure by a Market Participant to address a Margin Call may lead to the participant being declared by AEMO to be in default.

5.8 Facility and Rule Participant de-registration[46]

5.8.1 Facility de-registration

Market Participants may apply to de-register a Facility that is permanently ceasing operations. Any Facility other than a DSP or a Non-Scheduled Facility must notify AEMO at least three years before ceasing operations.

A Facility for which a Market Participant holds Capacity Credits for a given Reserve Capacity Cycle cannot be de-registered but may be transferred to another Market Participant.

5.8.2 Rule Participant suspension and de-registration

Rule Participants can be suspended if, among other things, they fail to meet their Prudential Obligations, fail to rectify a default situation, or become insolvent.

Rule Participants can also be de-registered. Rule Participants ceasing trading in the WEM may de-register themselves and their Facilities, and the ERA can compel Rule Participant de-registration if the relevant Rule Participant has been issued a Suspension Notice and has not rectified the cause for the suspension within 90 calendar days.

[45] If the prudential factor were to equal one, then a Margin Call could only be made once a Market Participant's debt to AEMO reached its Credit Limit, after which the debt could continue to increase until the participant was suspended a number of days later.

[46] De-registration and suspension processes are detailed further in clause 2.32 of the WEM Rules.

6 Power System Security and Reliability

Secure and reliable operation of the SWIS underpins the effectiveness and efficiency of the market.

AEMO must ensure that power system security and reliability in the SWIS are maintained in real time and over short- and medium-term planning timeframes.

Power System Reliability (PSR) relates to the ability of the power system to deliver electricity to users when they want it. Where PSR cannot be maintained, load may be shed to keep the power system operating.

Power System Security (PSS) relates to the ability of the power system to keep operating when unplanned events occur. If PSS is not maintained, equipment connected to the system can be damaged or fail (or disconnect to avoid damage or failure), with the potential for cascading impacts resulting in a system-wide blackout.

The WEM Rules provide several mechanisms to support and set boundaries for AEMO's operation of the SWIS. These include:

- Specified **Frequency Operating Standards** (FOS), which place clear boundaries within which AEMO must maintain the SWIS Frequency in normal operations and following Contingency Events.
- A **Technical Envelope** that describes the various limits of operation for the SWIS.
- The concept of **operating states**, which guide how AEMO plans, operates, and succinctly communicates the state of the power system, and provide clear guidance on the nature and timing of discretionary actions AEMO that can take under each condition.
- **ESS**, which define standardised non-energy services that AEMO procures to manage PSS.
- **Projected Assessments of System Adequacy** (PASAs), by which AEMO forecasts power system characteristics over various timescales so it and others can take steps to avoid PSS and PSR issues.
- **Mandatory Outage reporting and approval processes**, to ensure visibility of participants' plans, accurate forecasting of available supply and demand, and accurate operation of the central scheduling and dispatch process.
- **Power system monitoring and incident reporting**, providing the capability to monitor, assess and address PSS and PSR issues in the SWIS,
- A **Network Constraints Library**, used to represent the physical characteristics of the power system, allowing it to be accurately represented in the scheduling and dispatch process.

6.1 Frequency Operating Standards

To maintain PSS and PSR, AEMO must operate the SWIS within the 'Technical Envelope', which comprises the technical parameters set out in the WEM Rules, WEM Procedures, and the voltage standards in the Technical Rules for each Network in the SWIS.

The FOS are a core component of the Technical Envelope and provide safe operating parameters for system frequency under normal and abnormal system conditions[47]. They apply to the SWIS, and to embedded Networks

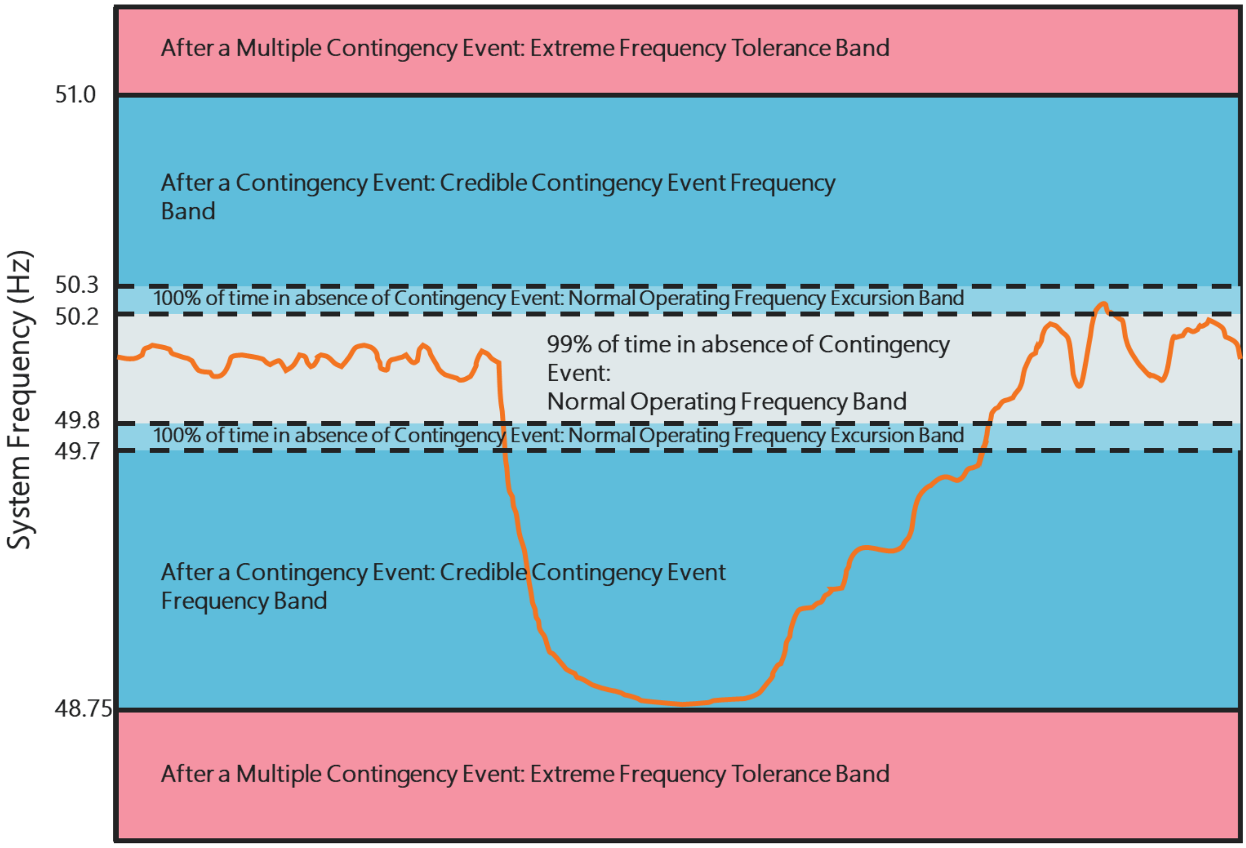
[47] Chapter 3B and Appendix 13 of the WEM Rules prescribe the FOS.

or microgrids while they are connected to the SWIS, and to electrical Islands within the SWIS when dispatched by AEMO.

Most of the time, the SWIS Frequency will be between 49.8 hertz (Hz) and 50.2 Hz. If a Contingency Event occurs, AEMO must act to ensure the frequency is stabilised and recovered within a certain time period[48].

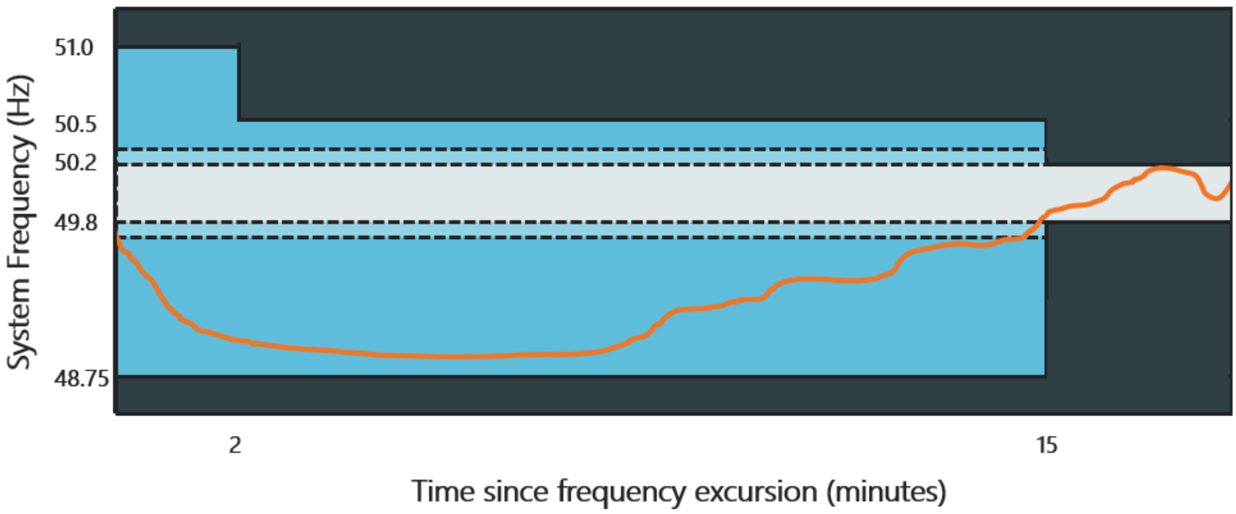
Figure 5 shows the Frequency Bands applicable to the SWIS, and Figure 6 shows the stabilisation and recovery times required following a single Contingency Event. Both figures show an example frequency trace for a hypothetical under-frequency event.

Figure 5 Non-Island Frequency Bands



[48] The FOS (Appendix 13) defines the Frequency Bands that AEMO may operate the SWIS within which includes the time within which AEMO must stabilise and recover frequency to return to the Normal Operating Frequency Band.

Figure 6 Stabilisation and recovery times following a single Credible Contingency Event



The FOS also provide a safe limit for the RoCoF for equipment connected to the SWIS. This is based on the ride-through capability of all equipment connected to the SWIS, including Energy Producing Systems, network components, and small and large end-consumer devices. The limit is expressed as Hz per second measured over any 500-millisecond timeframe, which recognises that the rate of change can vary throughout the duration of a frequency event, and the greatest change may not occur at the start of a frequency excursion event.

If the SWIS Frequency departs outside the Credible Contingency Event Frequency Band (below 48.75Hz), automatic Under Frequency Load Shedding (UFLS) relays will start disconnecting distribution network components to reduce load.

6.2 Operating states

The operating states framework provides a mechanism to determine the secure and reliable operating boundaries of the power system. It describes the actions AEMO may or must take in meeting one of its core objectives: to ensure the SWIS operates in a secure and reliable manner[49].

The operating states are the basis of the PSS Principles and PSR Principles, which form the foundation of many of AEMO's operational processes, such as Central Dispatch, Constraint development, Outage management, and PASA studies.

This ensures that when the power system is operating normally, AEMO maintains PSR and PSS in a structured, repeatable, transparent fashion, needing only limited powers to intervene in market processes. However, in times of system stress and emergencies, AEMO has additional powers to maintain or restore PSR and PSS by directing participants to take actions that affect market outcomes. AEMO's intervention powers are based around four operating states — one relates to PSR (Reliable Operating State), two relate to PSS (Satisfactory Operating State and Secure Operating State), and one is a catch all (Emergency Operating State):

- A **Reliable Operating State** applies when the power system can meet expected load and there are no constraints requiring load shedding; that is, no manual load shedding has occurred or is projected to occur. A

[49] Operating states are detailed in clauses 3.3 to 3.5 of the WEM Rules.

As far as is practicable, AEMO must operate the SWIS to remain in this state. When the SWIS is not in a Reliable Operating State, AEMO must take all reasonable actions to restore it as soon as practicable.

- A **Satisfactory Operating State** applies when the SWIS is operating within all parameters of the Technical Envelope; that is, the SWIS is operating within all relevant limits and in accordance with all relevant security standards. The SWIS should be in this state at all times, even after a Credible Contingency Event.
- A **Secure Operating State** applies when:
  - the SWIS is in a Satisfactory Operating State; and
  - if a Credible Contingency Event occurs, the SWIS will return to a Satisfactory Operating State within 30 minutes, whether or not AEMO intervention is required[50]
- An **Emergency Operating State** only occurs when declared by AEMO, when AEMO considers that circumstances exist that impact the ability of AEMO to operate the SWIS as intended under the WEM Rules.

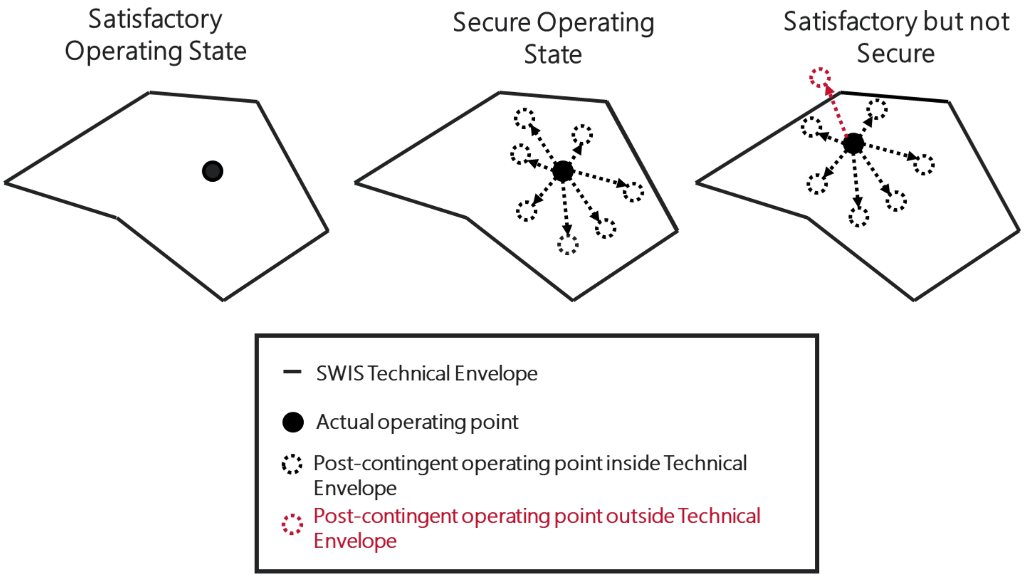
A Contingency Event[51] is any unplanned occurrence on the SWIS, including the failure or removal from service of one or more Energy Producing Units, Facilities, or Network elements, or an unplanned change in load, Intermittent Generation, or other elements of the SWIS not controlled by AEMO. A Credible Contingency Event is a Contingency Event that AEMO determines is reasonably possible in in the prevailing circumstances. Everything else is a Non-Credible Contingency Event. AEMO determines and publishes a list of Credible Contingency Events and can re-classify a Contingency Event that would normally be considered as non-credible as credible where circumstances indicate that there is a higher likelihood of it occurring (for example, where a bushfire is threatening multiple transmission lines). When AEMO re-classifies a Contingency Event, AEMO notifies Market Participants and makes operational adjustments, such as including additional Constraints in the Dispatch Algorithm, cancelling or recalling Outages, or directing participants to operate their equipment in particular ways.

Figure 7 illustrates the conceptual difference between Satisfactory and Secure Operating States.

[50] Immediately after a Credible Contingency Event occurs, the SWIS may no longer be in a Secure Operating State, but it will remain in a Satisfactory Operating State, because the system is operating with ‘n-1’ security.

[51] Refer also to clause 3.8A of the WEM Rules which defines Contingency Events and sets out AEMO’s obligations with respect to classifying Contingency Events.

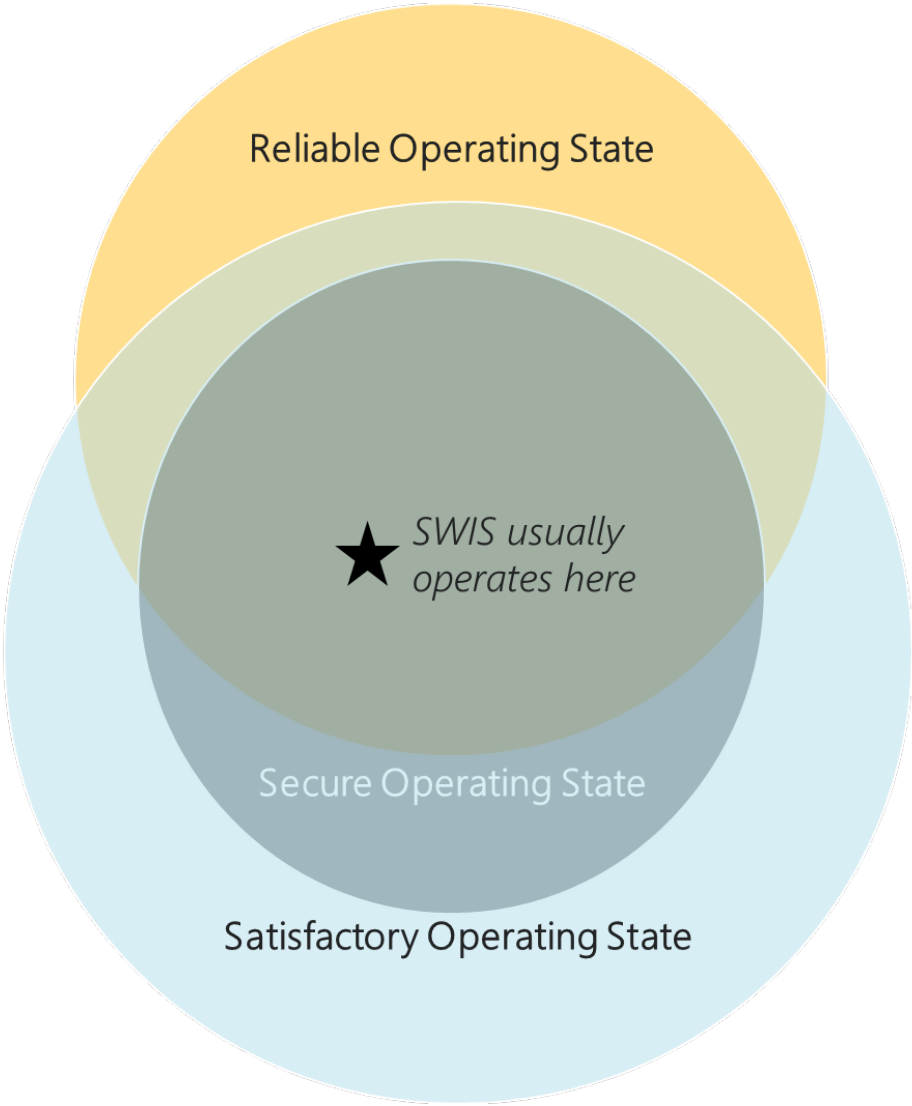
Figure 7 Satisfactory and Secure Operating States



The operating states are not mutually exclusive, and the SWIS can be in multiple states concurrently, as shown in Figure 8:

- The SWIS will usually simultaneously be in a Reliable Operating State, a Satisfactory Operating State, and a Secure Operating State.
- The SWIS can be in a Secure Operating State but not a Reliable Operating State. For example, where AEMO has directed load shedding to maintain PSS, some demand will be unserved, but the system can still handle a Credible Contingency Event.
- Conversely, the SWIS can be in a Reliable Operating State but not a Secure Operating State; for example, where a Non-Credible Contingency has occurred and all load is still being served, but the system is vulnerable to another contingency occurring and there is no capability to return to the Secure Operating State.
- The SWIS could theoretically be in a Reliable Operating State and neither Satisfactory nor Secure Operating States, but realistically load shedding would occur well before this situation occurred.

Figure 8 Reliable, Satisfactory, and Secure Operating States



If required to restore or maintain a Reliable Operating State, Satisfactory Operating State, and/or Secure Operating State, AEMO may intervene in market processes by rejecting or recalling Facility Outages, directing Facilities to adjust output in accordance with their GPS, or directing a Network Operator to operate or disconnect network equipment or curtail output of distributed solar PV through the 'Emergency Solar Management (ESM) scheme'[52]. In an Emergency Operating State, AEMO can also direct participants to provide ESS, operate their Facilities in a particular way, and take any other actions consistent with good electricity industry practice.

AEMO will issue a Market Advisory (see Section 8.10) if the SWIS is not in a Reliable Operating State or is in an Emergency State, or if AEMO has intervened or expects to intervene in market processes.

[52] Curtailment of distributed solar is a last resort option to increase net load on the SWIS for PSS reasons. When needed, AEMO advises Western Power of the change in demand it needs. Western Power then considers options to provide the requested change, and if distributed solar curtailment is necessary, advises Synergy (as the retailer) of the quantity (and potentially locations) to be curtailed. Synergy then issues instructions to affected customers. Affected customers are not compensated for curtailment.

6.3 Essential System Services

While energy is the primary commodity bought and sold in the WEM, other services are needed to support safe and secure operation of the power system. These ESS are becoming more and more and more important as the energy transition continues and conditions on the power system become more volatile.

There are two categories of ESS:

- **Frequency Co-optimised Essential System Services (FCESS)** are procured via the RTM[53].
- **Non Co-optimised Essential System Services (NCESS)** are procured in Bilateral Contracts between a Market Participant and either AEMO or the Network Operator.

ESS definitions and standards are detailed in clauses 3.9 and 3.10 of the WEM Rules.

6.3.1 Frequency Co-optimised Essential System Services

Using FCESS helps AEMO operate the SWIS to meet the FOS. AEMO determines what quantity of each FCESS it will need to meet the FOS, and schedules that in the RTM. Quantities for some are set in real time, others less frequently.

The following FCESS are defined in the market rules:

- **Regulation** functions to keep the SWIS Frequency close to 50 Hz by offsetting minor mismatches between electricity supply and demand. It is provided by Facilities capable of receiving Automatic Generator Control (AGC) signals from AEMO. Facilities can provide Regulation Raise service, Regulation Lower service, or both. When the SWIS Frequency is below 50 Hz, AEMO calls on Regulation Raise service by sending AGC signals to increase output (or reduce consumption) to raise the system frequency. When the SWIS Frequency is above 50 Hz, AEMO will send AGC signals to reduce output (or increase consumption) to lower the system frequency.
- **Contingency Reserve** functions to arrest, stabilise, and restore the SWIS Frequency after a Contingency Event occurs. It is provided by Facilities which hold capability in reserve to rapidly adjust output or consumption in response to significant changes in their local frequency. Facilities can provide Contingency Reserve Raise service, Contingency Reserve Lower service, or both. Contingency Reserve Raise service operates when there is a significant loss of generation. Contingency Reserve Lower service operates when there is a significant loss of load.
- **RoCoF Control Service** (RCS) functions to slow the RoCoF to within the RoCoF Safe Limit. It is provided by Facilities which contribute Inertia when synchronised to the power system.

When a contingency occurs, Contingency Reserve providers will respond using their reserved capability, and must be capable of holding the full response for up to 15 minutes. AEMO will seek to replace the 'used up' reserve and return to a Secure Operating State within that time.

RCS can be scheduled for two purposes — to ensure the requirements of the FOS are met, and to offset the need for Contingency Reserve Raise service. In all cases, there will be a minimum level of RCS required to ensure the RoCoF Safe Limit is maintained. However, increasing the amount of Inertia on the SWIS has an additional benefit

[53] Participants with new or upgraded facilities may receive additional payment under SESSM Awards, which allow for longer term support for availability of FCESS capable Facilities. Even so, the real-time dispatch and pricing for FCESS is conducted through the RTM.

in that it acts to reduce the quantity of Contingency Reserve Raise service required to maintain minimum frequency levels. The same thing happens with decreasing RoCoF. Therefore as part of the optimisation processes in the RTM, additional RCS will be scheduled where it is cheaper overall than scheduling higher quantities of Contingency Reserve Raise.

Facilities providing FCESS are subject to accreditation and testing processes, as discussed in section 5.6. FCESS can procured through the RTM (see Chapter 8) or through the SESSM (see Section 6.3.4).

6.3.2 System Restart Service

System Restart Services (SRS) assist in re-energising the SWIS in the event of a system-wide blackout or major supply disruption. SRS are provided by Facilities that can start without needing energy from the Network.

6.3.3 Non-Co-optimised Essential System Services[54]

The NCESS framework allows for the ad-hoc procurement of ESS to meet other system and Network needs[55].

Triggering NCESS procurement

The Coordinator of Energy has the power to trigger NCESS procurement, either based on a submission from AEMO or the Network Operator, or at its own discretion.

AEMO or the Network Operator must make a submission to the Coordinator to trigger a procurement if one or more of the following events have occurred:

- Energy Uplift Payments[56] increase to an uneconomic level indicating a Network Constraint that could be relieved via a locational network service.
- Frequent interventions by AEMO in the RTM[57] to relieve non-frequency Constraints (e.g., loss reactive power or System Strength) indicate a potential need for a locational network security service.
- Network planning assumptions (e.g., demand forecasts or profiles) change during the network planning timeframe indicating network service may be required (e.g., reactive power support or voltage stability).
- Changes to a PSS or PSR standard during the network planning timeframe necessitates the need to procure an NCESS
- AEMO considers that a significant threat to PSS or PSR exists or is emerging that cannot be addressed using the existing market mechanisms. For example, AEMO may be able to procure demand management services (including from DER) to mitigate system security threats associated with low levels of Operational Demand.

The first four trigger conditions enable the Network Operator to procure non-traditional alternatives to network augmentation.

The Coordinator can trigger an NCESS procurement as a result of a request from AEMO or the Network Operator, or as a result of identifying the need itself when one or more of the following occur:

[54] The NCESS framework is covered in clauses 3.11A and 3.11B of the WEM Rules.

[55] This section describes the post-NWCD NCESS regime. Before NWCD, an interim regime applied. For more information see AEMO's information paper

[56] See Section 10.4.1 on Energy Uplift Payments.

[57] See Section 8.7 on scarcity and intervention.

- The quantity of Energy Uplift Payments imposes unreasonable costs on the market.
- FCESS prices are unreasonable for a sustained period as a result of, for example, existing FCESS specifications not being fit for purpose[58][59].
- The WoSP (see Section 6.4.1) indicates alternative options for network augmentation may exist and are required.
- A rule change requires a new service to be procured.

NCESS procurement process

Upon deciding to trigger an NCESS procurement, the Coordinator will specify the party that shall procure the service. Network related services would be acquired by the Network Operator, while Market Services would be obtained by AEMO.

The procuring party must administer an Expression of Interest (EOI) process, which contains a clear service specification of the NCESS being procured. The purpose of the EOI is to assess whether capable resources exist to provide the service required before commencing the actual procurement process. The service specification may be modified as a result of EOI responses.

The decision to proceed with the procurement process is made by the procuring party in consultation with the Coordinator. The procuring party must then call for tender submissions in a public forum including the service specification, which must include (but is not limited to):

- The service requirements.
- The expected technical capability of Facilities or equipment able to provide the service.
- If relevant, the likely network location where the service is to be provided.
- The maximum quantity, timing, and duration of the service.
- Any operational requirements or limitations.
- Material contractual terms associated with the NCESS, including pricing structure.

Participation in procurement process

Participation is open to existing and new Facilities or equipment. Respondents can be either existing or intending Market Participants or providers who do not wish to register themselves or their Facilities (see Selection process below). Respondents must make an NCESS Submission which must include (but is not limited to):

- Facility or equipment details including quantity of service to be provided, location, operational requirements and limitations, and whether it currently or intends to participate in the RTM to provide energy and/or FCESS.
- If the Facility or equipment comprises technology that would ordinarily be capable of being assigned CRC, then information demonstrating it can meet the certification process requirements (see Section 7.4.1). Otherwise, the respondent must provide information demonstrating that it cannot meet certification requirements (see Selection process below for certification requirements).

[58] For example, if Regulation costs are excessive as a result of AEMO increasing Regulation requirements to ensure PSS during the morning or evening ramp, the procurement of an NCESS ramping product could be considered.

[59] An exception is where FCESS prices are indicative of potential abuse of market power, in which case the ERA may trigger the Supplementary Essential System Services Mechanism (SESSM) to procure the relevant FCESS contractually (see Section 6.3.4).

- Pricing and cost information including:
  - Fixed costs and expected Capacity Credit payments.
  - The highest price at which the Facility or equipment would provide NCESS.
  - Any other payments required to provide the NCESS.

Selection process

AEMO or the Network Operator (as the relevant procuring party) will select winning NCESS Submissions based on the extent to which the submissions:

- Meet their requirements; and
- Maximise value for money.

Providers associated with selected NCESS Submissions must:

- Enter into a contract with AEMO or the Network Operator (as relevant).
- If the service provider is required to register themselves (as a Market Participant) and/or their Facility (in a Facility Class) under the registration provisions of the WEM Rules[60], apply for Rule Participant and Facility registration as relevant. Practically, this means that service providers providing NCESS from small Facilities (less than 10 MW) may not need to register. This provides AEMO and the Network Operator the ability to procure NCESS from non-traditional sources such as DER or from equipment such as synchronous condensers.
- Apply for certification where the Facility providing the NCESS ordinarily be capable of being assigned CRC. AEMO and the Network Operator can vary the payment terms of an NCESS Contract to subtract Capacity Credit payments from the total NCESS payment. This provision ensures that NCESS providers do not attempt to recoup capital costs using both RCM and the NCESS framework.

NCESS coordination and dispatch

When an NCESS procured by the Network Operator affects AEMO's scheduling and dispatch processes (e.g., where a Registered Facility offering energy and FCESS is also providing a locational network service), the Network Operator and AEMO will agree to process the relevant Facility to ensure that it can be dispatched for all relevant services appropriately.

AEMO may dispatch a Facility for NCESS by developing NCESS Constraint Equations (see Section 8.3.1), with NCESS dispatch being prioritised over energy and FCESS.

6.3.4 The Supplementary Essential System Services Mechanism[61]

Overview

FCESS are primarily procured via the RTM, in which all accredited Facilities can participate. However, in a small, concentrated market like the WEM, it is possible that the RTM alone may not function optimally. To protect

[60] See Section 5.2.

[61] Clauses 3.15A and 3.15B of the WEM Rules describe the SESSM framework in further detail.

against this risk, the WEM includes the SESSM to enable longer-term arrangements while minimising distortion to RTM outcomes.

The SESSM operates to:

- Mitigate scarcity in FCESS markets. Scarcity may manifest either as a shortfall of FCESS from accredited Facilities, or a shortfall due to low participation in the RTM.
- Mitigate market power by:
  - Supporting the entry of new FCESS providers where necessary, thus introducing further competition into the RTM.
  - Allowing ex-ante review of the operating costs of FCESS providers by the ERA.

A SESSM Award does not mean that a Facility is dedicated to actually providing FCESS. The Market Participant may receive an Availability Payment to make the FCESS capability available in the RTM, but the Facility will still be dispatched based on the least-cost combination of offers. If dispatching other providers for FCESS is the most cost-effective option for a given Dispatch Interval, the SESSM Award holder will not be dispatched to provide FCESS.

Triggering the SESSM

The SESSM can be triggered by AEMO or the ERA and will be triggered if:

- AEMO identifies a shortfall of FCESS capable Facilities, either where:
  - The total accredited capability for a particular FCESS is less than the forecast requirement and this is not expected to be met by new entry (an Accreditation Shortfall); or
  - AEMO has consistently had to direct accredited Facilities to provide FCESS to fill a forecast real-time shortfall that was not resolved by market activity in response to a LRCD (a Participation Shortfall).
- The ERA identifies through its monitoring activities that market outcomes are not consistent with efficient operation; for example where a participant increases offer prices in situations where it has market power, or where overall market prices are significantly above a level that should attract new investment.

In some cases the Coordinator may consider that it is more appropriate to procure NCESS rather than trigger the SESSM. For example, overall FCESS market costs could increase if AEMO increased Regulation requirements to provide flexible capacity to meet ramping requirements. Regulation can serve this need, but it is not explicitly designed to do so. In such a situation, the Coordinator, ERA, and AEMO would discuss the options and determine the most appropriate approach. The ERA's decision making power is independent from the Coordinator's, but each can take the other's plans into account.

When the SESSM is triggered in response to a shortfall, AEMO will define a service specification aligning with the forecast shortfall, and the required amount will be procured via the SESSM.

When the SESSM is triggered by the ERA in response to inefficient market outcomes, AEMO will define a SESSM Service Specification for the relevant FCESS, aligning with the times and situations in which inefficient outcomes are observed. The entire forecast FCESS requirement for that service in those periods will be procured via the SESSM.

The SESSM Service Specification will set out:

- The service to be procured.
- The required start date for the service.
- The Dispatch Intervals for which the service is required.
- The proposed duration of awards to be made.
- The profile of quantities required in each applicable Dispatch Interval.
- The percentage of time in which the Facility must offer the service before starting to incur refunds of the Availability Payment.

Participating in the SESSM

Both existing and new Facilities can participate in the SESSM.

When the SESSM is triggered due to a forecast shortfall in capacity, existing Facilities may only participate if proposing an increase in their accredited FCESS capability.

When the SESSM is triggered due to inefficient market outcomes, the ERA can mandate participation by specific Participants or Facilities assessed as potentially contributing to inefficient market outcomes. The ERA:

- Can designate Registered Facilities but not prospective Facilities.
- Can only designate a Facility for participation in a SESSM procurement for a FCESS for which it is accredited.
- Cannot designate a Facility which already has a current SESSM Award for the relevant service unless the new service specification covers additional capacity or time periods not included in the current award.
- Can only designate Facilities or participants which are able to meet the service specification.

Even where the ERA nominates mandatory participation, the SESSM procurement process remains open to new Facilities and to existing Facilities not currently providing FCESS.

SESSM Submissions

Interested Market Participants will make a SESSM Submission for each participating Facility. SESSM Submissions must comply with the SESSM Service Specification, and include the participant's proposed values for:

- **Availability Quantity** – the quantity of FCESS that the Facility will make available in the RTM, which can vary over time.
- **Award Duration** – the period over which the Facility will provide the service under a SESSM Award, which will usually be between one and three years.
- **Availability Payment** – the fixed amount to be paid to the participant in return for making the Availability Quantity available in the RTM.
- **Offer Cap** – the price below which the participant commits to offer FCESS into the RTM. Participants can offer more than this to recover Enablement Losses (start-up and minimum energy generation costs where the Facility would not be running if it were not needed to provide FCESS).

SESSM Submissions for existing Facilities must include information allowing comparison with historical FCESS offers, and submissions for proposed new Facilities must include information about expected operating characteristics and evidence of ability to deliver to the service specification.

Determining SESSM Awards

AEMO will select SESSM Submissions that meet the SESSM Service Specification and result in the lowest cost of providing the FCESS to the market, when compared with historical market outcomes.

AEMO's process for selecting the lowest cost combination of SESSM Submissions involves:

- Discarding submissions not complying with the service specification.
- Excluding submissions for new Facilities where insufficient evidence has been provided to give confidence that the Facility will be able to provide the service.
- Identifying historical Dispatch Intervals matching the service specification.
- Calculating three per-interval energy price profiles matching the SESSM Service Timing (high, medium, and low).
- Calculating effective FCESS offer prices for each SESSM Submission.
- Calculating the lowest-cost combination of submissions to deliver the requirement under each of the three energy price profiles.

Where the SESSM was triggered to respond to FCESS shortfall, the ERA can veto AEMO's proposed SESSM Awards or ask it to revise the selection, but only if AEMO has not followed the process set out in the WEM Rules.

Where the SESSM was triggered to respond to inefficient market outcomes, the ERA can veto one or more of the proposed SESSM Awards if it thinks the relevant SESSM Submission was unreasonable, or that making the Award will not lower market costs.

Final SESSM Awards are made public, but SESSM Submission data remains confidential to AEMO and the ERA.

Conditions of holding a SESSM Award

Successful Facilities will be issued a SESSM Award on the terms set out in the SESSM Service Specification and the SESSM Submission.

Proposed new or upgraded Facilities must register in the WEM as soon as possible and provide regular reports on progress towards commissioning. If unable to demonstrate sufficient progress towards commissioning, AEMO may revise the SESSM Service Commencement Date, or cancel the SESSM Award.

Participants holding a SESSM Award are required to offer the relevant Facility into the RTM as follows:

- The quantity of Available and In Service Capacity for the Facility in respect of that FCESS must be at least the relevant SESSM Availability Quantity.
- The FCESS offer price must not exceed the SESSM Offer Cap prescribed under the Award, except that:
- If the Facility is forecast to run at its Minimum Enablement Limit, the offer price can account for Enablement Losses (as discussed in section 8.2); and
- Where the participant does not expect to recover its start-up costs through energy revenue, the FCESS offer price can account for start costs amortised across expectation of running period.

- If the Pre-Dispatch Schedule forecasts that the Facility will be cleared for FCESS if it were running, the participant must ensure that the Facility is In Service and operating for energy at or above its Enablement Minimum so as to be able to provide FCESS in the relevant Dispatch Intervals.

Facilities which were previously accredited to provide FCESS may also have a 'Base ESS Quantity' representing previously awarded FCESS capability, which must be made available in addition to the Availability Quantity. This is necessary to ensure that the SESSM Award actually increases the quantity of ESS available to address a shortfall. Where a Facility holds a SESSM Award for only part of its total FCESS capability, the offer price for non-SESSM-Award capacity is not restricted to the SESSM Offer Cap.

SESSM refunds

Where a Facility receives a non-zero Availability Payment but is not available to the extent required under its SESSM Award (that is, where its availability falls below the SESSM Availability Requirement), it is required to refund a portion of the Availability Payment.

The Facility is considered not fully available in any interval where it is not offering sufficient FCESS to meet its Availability Quantity. Some SESSM Awards may allow the Facility to be unavailable for a small number of intervals without incurring refunds – particularly where the award covers many hours over a long period. Awards for short periods of time or for only part of the year will likely incur refunds for any unavailability.

The refund:

- Is automatically calculated by AEMO in accordance with Appendix 2C of the WEM Rules, based on the proportion of the Availability Payment that relates to a single Dispatch Interval.
- Uses a refund factor of 3 so that the refund represents proportionally more than the payment in respect of a single Dispatch Interval.
- Is pro-rated according to the quantity of RTM Offer Shortfall, to provide incentive for Facilities to offer as much as they can.
- Is capped so total refunds will not exceed the total Availability Payments payable to the Facility over the duration of the award.

If a Facility consistently fails to offer in accordance with its SESSM Award, AEMO can adjust the Availability Quantity to reflect the actual capability of the Facility, and pro-rate the Availability Payment accordingly.

Expressions of Interest process

Every two years, AEMO seeks EOI from current and prospective Market Participants in providing FCESS from new or upgraded Facilities.

AEMO provides information about historical requirements for FCESS, and Market Participants can respond with information like that which would be provided in a SESSM response, including likely costs, timeframes, and Facility characteristics. All information is completely non-binding and remains confidential to AEMO and the ERA. The ERA can use the information in its monitoring and review functions, and to support its determination of whether market outcomes are such that it should trigger the SESSM.

6.3.5 ESS cost recovery

The rules discussed in this section are currently under review by EPWA. This section will be revised in a future release as more information becomes available.

Rule Participants pay for the cost of ESS on the following basis:

- Regulation costs are recovered from Non-Dispatchable Loads, Semi-Scheduled Facilities, and Non-Scheduled Facilities in proportion to the absolute values of their metered generation or consumption in the relevant Trading Interval.
- Contingency Reserve Raise costs are recovered from Registered Facilities injecting above 10 MW based on their cleared generation and ESS in the relevant Dispatch Interval, using a runway method (see Section 10.4.3 for a detailed discussion on the runway method).
- Contingency Reserve Lower costs are recovered from Registered Facilities and Non-Dispatchable Loads in proportion to their metered consumption in the relevant Trading Interval.
- RCS costs are recovered in two portions:
  - The portion relating to the minimum requirement to maintain Power System Security is recovered in equal share from the groups of causers of the need for the service, which may include:
    - The Network Operator;
    - Loads in proportion to their absolute values of metered generation or consumption in the relevant Trading Interval; and
    - Energy-producing Facilities according to their metered generation in the relevant Trading Interval.

    Rule Participants do not have to pay for this first portion if their Facilities (including the Network) have an accredited RoCoF Ride-Through Capability greater than the RoCoF Ride-Through Cost Recovery Limit (see Section 10.4.4 for a detailed discussion of how the first portion is cost-recovered).
  - An additional portion is only procured if it reduces the overall cost of supply (by reducing the required quantity of Contingency Reserve Raise). It is recovered on the same basis as Contingency Reserve Raise, from Facilities injecting above 10 MW based on their cleared generation and ESS in the relevant Dispatch Interval, using the runway allocation method as described above.
- System Restart costs are recovered from Registered Facilities and Non-Dispatchable Loads in proportion to their metered consumption in the relevant Trading Interval.
- NCESS costs (for services procured by AEMO) will be recovered from Registered Facilities and Non-Dispatchable Loads in proportion to their metered consumption in the relevant Trading Interval. NCESS procured by the Network Operator is settled and cost-recovered off-market.

6.4 Planning and forecasting

6.4.1 Whole of System Plan[62]

Every five years, the Coordinator prepares a WoSP for the SWIS, with the assistance of AEMO and the Network Operator.

The WoSP looks forward at least 20 years, to support the efficient development of the SWIS by interested parties, including both monopoly (Networks) and competitive (generation, consumption and storage) entities.

It does not seek to define a single expected future, but rather considers a number of possible Scenarios with a wide range of underlying assumptions about economic and demand growth, technology development and cost, and available network upgrade options. Using a range of Scenarios provides insight into 'least regrets' options for network and generation investment, and the use of non-network solutions (such as demand side response).

The WoSP can also identify 'Priority Projects' for the Network Operator to progress.

WoSP outputs are considered when the ERA assesses the Network Operator's proposed network investments.

6.4.2 Transmission System Plan[63]

Each year, each registered Network Operator prepares a Transmission System Plan (TSP) for its Network, in consultation with AEMO and the Coordinator.

The TSP looks forward at least 10 years, considering current and future transmission constraints, their effects on the WEM, and the expected cost to consumers. The output is a recommended development path for the transmission system and a high-level assessment of how the recommended plan will meet the long-term interest of consumers.

The Network Operator publishes a draft plan for comment before producing a final version before 1 October each year.

6.4.3 Projected Assessment of System Adequacy

As part of ensuring PSS and PSR, AEMO forecasts system adequacy over three time periods. These assessments allow AEMO, Market Participants, and Network Operators to understand projected conditions on the power system and factor those into their decision-making. In particular, the information gives AEMO a view of the power system conditions likely to apply at different times in the future, assisting it to schedule Outages and plan the secure and reliable operation of the power system.

AEMO conducts three PASA studies:

- The **Long-Term PASA (LT-PASA)** is conducted annually, looking ahead 10 years. It provides input to the RCM, which procures capacity to meet a forecast Reserve Capacity Target. The LT-PASA is discussed further in Section 7.3.
- The **Medium-Term PASA (MT-PASA)** is conducted at least weekly, looking ahead three years, with output provided for each day in the forecast horizon. MT-PASA provides input to Outage assessment, projects the

[62] Refer to clause 4.5A of the WEM Rules for more information about the WoSP.

[63] Refer to clause 4.5B of the WEM Rules for more information about the Transmission System Plan.

likelihood of Low Reserve Conditions (LRCs) based on expected annual unserved energy, and informs the need for AEMO to intervene in market processes (as discussed in Section 6.2) or to trigger the SESSM due to a projected shortfall.

- The **Short-Term PASA (ST-PASA)** is conducted at least daily, looking ahead one week, with output provided for each 30-minute Trading Interval in the forecast horizon. This finer resolution supports operational planning in the leadup to real-time, such as finalising ESS requirements, issuing Low Reserve Condition Declarations (LRCDs), and considering potential Outage cancellations. It aligns with the longest Pre-Dispatch Schedule in the RTM (see Section 8.7) and uses some of the same inputs.

Market Participants and Network Operators provide information for each of the PASA horizons:

- Network Operators provide information on changes to transmission capacities and ratings of equipment and planned network augmentations.
- Market Participants provide modelling information and factors that will change the amount of energy they purchase. Where possible, ST-PASA uses data from Outages and RTM submissions so participants only have to provide information once.

Both MT-PASA and ST-PASA use probabilistic modelling to account for the variety of different possible input assumptions. Outputs are published on the WEM Website, and include:

- Expected demand, peak load, and ESS requirements.
- Total unconstrained supply capacity, ESS capability, and capability of demand-side resources.
- Network capability and congestion, including binding or violated Network Constraints.
- Likelihood, level, and timing of unserved energy, loss of load probability, and ESS shortfalls.

Where AEMO identifies a risk of insufficient scheduled or Available Capacity to meet forecast demand, binding or violating Constraints requiring load shedding, or ESS shortfalls, AEMO will issue a LRCD indicating:

- The nature of the security or reliability risk.
- The likelihood of the security or reliability risk materialising.
- The time period over which the identified risk applies.
- Information relating to how and when AEMO may need to intervene if the risk persists.

Once a LRCD has been issued, AEMO will update the details as conditions change and may seek clarifying information from participants to assist in updating the details of the LRCD.

6.5 Outages[64]

Good visibility of future Network and Facility Outages is essential to assist participants in effective availability planning for their Facilities, and for producing overall efficient market outcomes. Network Outages, in particular, can have a pronounced impact on the levels of network congestion, which flows on to the ability to schedule and dispatch sufficient generation to meet demand.

[64] The Outage planning processes are covered in detail in clauses 3.18 to 3.20 of the WEM Rules.

Market Participants are required to tell AEMO when their Registered Facilities are unavailable for dispatch by submitting Planned Outages and Forced Outages through AEMO's systems. Participants must have approval for Planned Outages and must provide information about Forced Outages as soon as possible. There are two main reasons for this:

- AEMO needs this information to accurately forecast expected power system conditions, including reserve margins and appropriate Constraints Sets for use in the Dispatch Algorithm. They can reject an Outage request if necessary to ensure sufficient capacity will be available to meet projected demand for energy and ESS and to ensure PSR and PSS can be maintained.
- Participants receiving capacity payments through the RCM are compensated for making their Facilities available. If a Facility is not available because of an unplanned or unapproved Outage, it is not meeting its Reserve Capacity Obligations, and thus, part of the capacity payment must be paid back. The details of the Outage are used to calculate the size of the capacity refund.

6.5.1 Participation in the Outage process

AEMO compiles a list of all equipment on the power system that is required to schedule Outages, including partial Outages and de-ratings[65]. This list includes Facilities holding Capacity Credits[66], Facilities that provide ESS, items of network equipment that could limit the output of such Facilities, and any other equipment that could affect the PSS and PSR. Market Participants may request that AEMO reassess the inclusion of their equipment on this list.

Facilities not on the Equipment List are known as Self Scheduling Outage Facilities (SSOFs). Participants must still submit Outage Plans for SSOFs, but the Outage Plans are not subject to AEMO assessment, and are deemed approved unless explicitly rejected by AEMO for not meeting required submission deadlines or misrepresenting availability status.

6.5.2 Outage approval

Market Participants can request approval for Planned Outages with specific start and end Dispatch Intervals up to three years ahead. The request must include:

- The reason for, timing of, and duration of the proposed Outage.
- Potential risks to the intended duration of the Outage.
- Contingency plans should the Facility need to be returned to service prior to the scheduled Outage Completion time. Except in a few limited situations (such as when requesting an extension of a Planned Outage currently underway), a request for a Planned Outage can only be made where the participant reasonably believes that the Facility would otherwise be available for service.

Planned Outage requests must indicate the Remaining Available Capacity (RAC) for dispatch during the Outage. For a full Outage (where the Facility is completely unavailable), the RAC would be 0 MW. For partial and overlapping Outages, the RAC can vary over the duration of the Outage. Where a Planned Outage impacts the provision of an ESS or relates to a component of the Facility that has been separately accredited for Reserve Capacity, the Outage request must also include information on each affected service and component.

[65] At https://aemo.com.au/-/media/files/electricity/wem/data/system-management-reports/equipment-list.pdf.

[66] Excluding Demand Side Programmes.

While participants can request Outages up until two days before the event — or even up to two hours ahead for ‘Opportunistic Maintenance’ Outages of less than 24 hours — AEMO may reject a request if there is insufficient time to assess the impact of the Outage. Most Outages are notified to AEMO well in advance of their commencement, and in many cases more than a year before the event.

AEMO will usually review Outage Plans in the order received, and will approve an Outage Plan provided sufficient energy supply and network capacity will remain to maintain PSR and PSS. Once approved, Outage Plans continue to be reviewed periodically by AEMO to ensure they can still be accommodated as power system conditions change (for example, where Unplanned Outages occur). When changed conditions may result in an Outage potentially needing to be re-scheduled, AEMO will notify the Market Participant that the Outage is ‘at risk’. Approved Outages are also subject to a final check with the AEMO control room before commencing, with certain equipment requiring ‘permission to proceed’ to ensure the supporting configuration is in place (such as applying appropriate Constraints in the Dispatch Algorithm). Permission to proceed would typically only be denied if something unusual or unexpected is occurring.

Rule Participants must advise AEMO of changes to previously submitted Outage Plans, and must formally withdraw an Outage Plan if they are no longer planning to make the equipment unavailable.

AEMO publishes information on submitted Outage Plans on the WEM Website, including status, timing, and details of the affected equipment or services.

6.5.3 Forced Outages

Participants must also advise AEMO of Forced (unplanned) Outages:

- Participants must notify the AEMO control room as soon as possible with initial information on the Forced Outage, such as the affected equipment or service, the Remaining Available Capacity, the nature of the failure, and any indicative restoration timeframe.
- Participants must submit a Forced Outage entry with full details of the Outage into AEMO’s Outage system no later than the end of the next Business Day after the day the Forced Outage occurred.
- Participants must update the Forced Outage entry with any material changes to Forced Outage information as soon as practicable, with final information required no later than 15 calendar days after the day the Forced Outage occurred.
- If AEMO becomes aware of New Information relating to a Forced Outage, it can require a participant to submit or revise a Forced Outage entry, even after 15 calendar days.

Forced Outage data is used to calculate any required Reserve Capacity refunds. AEMO publishes Forced Outage information on the WEM Website.

6.5.4 Outage Intention Plans

By 1 March every year, Market Participants and Network Operators must submit a non-binding ‘Outage Intention Plan’ listing their intentions for Outages in the next calendar year, providing indicative information for expected Outages which have not yet been submitted[67]. This information helps coordinate network and Facility Outages. AEMO uses the information provided to construct and publish a consolidated Outage Intention Plan covering all

[67] Self-Scheduling Outage Facilities are exempt from this requirement. Self-Scheduling Facilities are small Facilities such as Non-Scheduled Facilities whose Outages AEMO does not require visibility of.

Rule Participants. Where individual participant plans conflict, AEMO and participants work together to find an alternative plan. While Outage Intention Plans are not binding on participants or AEMO and individual Outages must still be requested and approved via the normal process, Outages signalled in an Outage Intention Plan do have some priority over Outages not included in an Outage Intention Plan.

6.5.5 Outage coordination

Some network Outages affect the ability of Market Participants to operate their Facilities as they wish. For example, a line Outage could mean that maximum Injection from a Facility cannot be accommodated by the remaining network components. It is generally desirable, but not always possible, to schedule these network Outages at mutually agreeable times. Network Operators are required to notify Impacted Participants and seek mutual agreement on Outage timing, before submitting the Outage Plan to AEMO at least six months in advance. If no agreement is reached, the Impacted Participant may request that AEMO determine whether the proposed Outage Plan should be revised, having regard to:

- Maintaining PSR and PSS.
- The relative dates on which the Outage was notified.
- Whether the Outages were signalled in an Outage Intention Plan.
- The urgency of any required maintenance, and the impacts of not performing that maintenance.
- The impacts of rescheduling the Outage.

Where AEMO rejects an Outage Plan, the affected participant can appeal to the ERA, but only on the grounds that AEMO has not met the requirements of the WEM Rules or the relevant WEM Procedure.

6.5.6 Outage cancellation and recall

Sometimes AEMO needs to recall or cancel an Outage it has previously approved. If power system conditions or forecasts change after an Outage is approved, AEMO can notify a participant that its Outage is ‘at risk’ of rejection. If proceeding with the Outage poses a risk to PSS or reliability, AEMO may reject the Outage or recall the Facility to service early. When rescheduling, Outages that were previously rejected or recalled in this way get priority over new Outages.

If an Outage is submitted at least a year prior to commencement, then approved, and then rejected within 48 hours of its commencement or recalled by AEMO, the affected party can apply for Outage Compensation to cover additional maintenance costs directly incurred in relation to the rejection or recall. Compensation is funded from Market Participants based on their energy consumption in the affected Trading Intervals.

6.5.7 Effect of Outages on Reserve Capacity Obligations

When Planned Outage requests are approved by AEMO, they are designated as Planned Outages, and the Reserve Capacity Obligation Quantity (RCOQ) of the affected Facility is reduced to reflect the Outage during the impacted Trading Intervals. If the Facility has Planned Outages with duration totalling more than approximately six months over a rolling 1,000-day horizon, the RCOQ is not reduced, and the Market Participant will be required to refund Reserve Capacity Payments.

All other Outages are Forced Outages. As described in Section 6.5.3, Market Participants are obliged to inform AEMO of Forced Outages as soon as practicable, and to provide information concerning when the Facility will return to service. Market Participants are required to refund Reserve Capacity payments when their Facilities suffer Forced Outages (see Section 7.4.3). For the purposes of refund calculations, Charge Level shortfalls for Electric Storage Resources are treated as Forced Outages.

6.6 Network Limits and Constraint Equations[68]

Security Constrained Economic Dispatch supports secure and reliable power system operation by incorporating consideration of physical power system characteristics (such as network limitations, supply/demand balance, and ESS requirements) into the scheduling and dispatch process. These characteristics are represented in the Dispatch Algorithm by 'Constraint Equations', which must be respected by the software while scheduling and dispatching Facilities. Constraint Equations are mathematical representations that AEMO uses to manage power system limitations and ESS requirements.

Constraint Equations for network limitations are key inputs to constrained optimisation calculations in the WEM dispatch engine and are also used to inform the allocation of Network Access Quantities (and hence Capacity Credits) to Facilities participating in the RCM.

6.6.1 Limit Advice

Constraint Equations for network characteristics are formulated based on limits that affect how energy can flow through the network and the contingencies which can affect flow on each network element. AEMO develops Constraint Equations based on Limit Advice from Network Operators. There are two types of Network Limits:

- A **Thermal Limit** represents the maximum energy that can be transmitted through a piece of network infrastructure. For example, if too much energy is transmitted through a line it can overheat, causing it to sag, melt, and potentially break. A Thermal Limit defines the boundary within which a particular piece of equipment can be safely operated.
- A **Non-Thermal Limit** represents other system security and stability limitations. For example, electrical equipment operating at voltages outside of normal operation for too long will be damaged. A Non-Thermal Limit may apply to more than one piece of network equipment.

In preparing Limit Advice, the Network Operator must explicitly consider the risk margins it uses to account for uncertainty, and must include them in the information provided to AEMO.

6.6.2 Constraint Equations

AEMO uses the Limit Advice from Network Operators to build Network Constraint Equations for use in the Dispatch Algorithm.

In their simplest form, Constraint Equations specify that Facility output must be less than a defined limit. For example, a Facility with no co-located Load connected to the SWIS by a single transmission line might have a constraint in the form given in Equation 2.

[68] See also clause 2.27A of the WEM Rules.

Equation 2: Generic single Facility line limit constraint

$$Injection_{Facility1} \leq Limit$$

That is, the output of the Facility must be less than or equal to the capacity of the line. Constraint Equations for Network Limits are constructed as 'less than or equal to' equations, while FCESS constraints (see Section 8.3) are 'greater than or equal to' constraints, requiring a minimum quantity of a particular ESS to be scheduled.

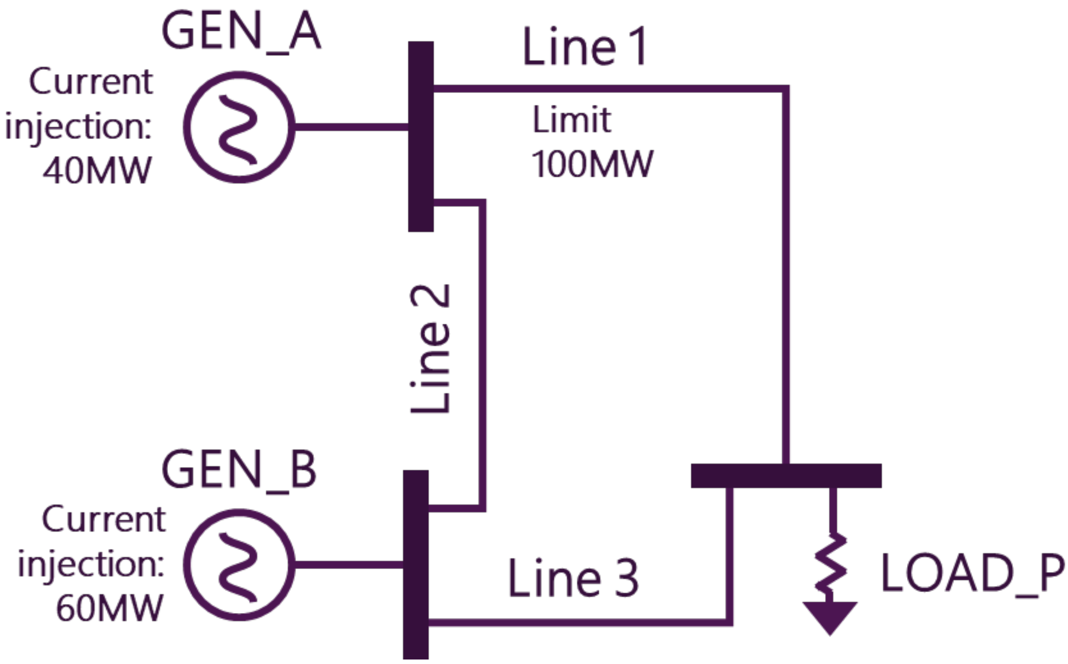
In practice, the topography of the transmission network means equations need to account for multiple Facilities which contribute unequally to the flow on a line. A more generic formulation is depicted in Equation 3.

Equation 3: Generic multi-Facility line limit constraint

$$Coefficient_{Facility1} \times Injection_{Facility1} + Coefficient_{Facility2} \times Injection_{Facility2} + \cdots + Coefficient_{FacilityN} \times Injection_{FacilityN} \leq Limit$$

Where the output of a particular Facility affects the flow on a line only slightly, it has a small coefficient. Where a particular Facility has a large effect on the flow on a line, it has a larger coefficient. The effect a particular Facility has on the flow on a particular transmission line will be reflected differently in Constraint Equations depending on which network elements are in service.

Figure 9 Example two generator, three line system



In the example above, an equation enforcing the simple Thermal Limit on Line 1 (the 'monitored element') in the network in Figure 9 might generically look like Equation 4. The coefficients indicate that a 1 MW increase in output by GEN_A increases the flow on Line 1 by 0.75 MW, and a 1 MW increase from GEN_B increases the flow by 0.5 MW.

Equation 4: Example line limit constraint

$$0.75 \times Injection_{GEN\_A} + 0.5 \times Injection_{GEN\_B} \leq 100$$

Terms on the left-hand side (LHS) of a constraint reflect parameters that can be controlled by the Dispatch Algorithm (such as Facility output or Scheduled Load consumption). Terms on the right-hand side (RHS) represent:

- Parameters that are inputs to the Dispatch Algorithm (such as the Thermal Limit of a piece of network equipment, the current output of a Facility, the current flow on a line, the measured voltage at a particular network location, or the demand from Non-Dispatchable Load at a particular network location); or
- Parameters that cannot be optimised by the linear solver (for example, where the limit calculation includes the square of the output of a Facility).

Coefficients are determined by conducting Load flow studies and defined with reference to the Southern Terminal 330 kilovolt (kV) busbar — the Reference Node — and the same location Loss Factors are defined in relation to.

When used for real-time dispatch, the RHS will incorporate the real-time flow on the line and the current output of the Facilities in the constraint (including the same coefficients), as well as an 'Operating Margin' used by AEMO to reflect uncertainty. For example, if Line 1 had a real-time flow of 75 MW and an Operating Margin of 10 MW, the dispatch version of the constraint might look like Equation 5.

Equation 5: Example line limit dispatch constraint

$$0.75 \times Injection_{GEN\_A} + 0.5 \times Injection_{GEN\_B} \\ \leq Limit_{Line\ 1} - Actual_{Line\ 1} - 10 + 0.75 \times Actual_{GEN\_A} + 0.5 \times Actual_{GEN\_B}$$

$$0.75 \times Injection_{GEN\_A} + 0.5 \times Injection_{GEN\_B} \leq 100 - 75 - 10 + 0.75 \times 40 + 0.5 \times 60$$

$$0.75 \times Injection_{GEN\_A} + 0.5 \times Injection_{GEN\_B} \leq 75$$

A separate version of this constraint would exist for each Credible Contingency Event that result in a changed flow on Line 1, with an additional term on the RHS representing the post-contingency flow transferred to Line 1. In this example, that might be equations for the loss of Line 2 and Line 3.

Equations used in pre-dispatch and PASA are slightly different, and other adjustments and refinements are made to make Constraint Equations suitable for use in the Dispatch Algorithm (such as scaling equation terms relative to the largest coefficient and moving Facilities with small coefficients to the RHS).

As a result, the Constraints Library includes thousands of Constraint Equations, potentially containing one equation for each combination of limit, network configuration, and Credible Contingency Event. That is, there will be a set of equations:

- For each different network configuration (which equipment is in service, how that equipment is connected, and what the level of demand is);
- For every Equipment Limit (Thermal and Non-Thermal) provided by the Network Operator in Limit Advice. The equations describe how Facility output will affect the limit; and
- For every Contingency Event (the unexpected failure or disconnection of a Facility or a specific network element, or a significant unplanned change in Load or Facility output) that AEMO considers could credibly affect the power system.

AEMO manages the size of the Constraints Library by focusing on Constraint Equations with larger Facility coefficients, and those actually expected to 'bind' — where Facility output must be restricted to avoid going over the limit — and on common and anticipated network configurations and Outage conditions.

6.6.3 Congestion Information Resource[69]

Transparent information about the physical capability of the network and its effect on market outcomes supports participants to make decisions about investing in new Facilities and operating existing Facilities, and Network Operators to plan for network augmentation.

To this end, AEMO publishes a Congestion Information Resource that provides public access to Limit Advice, the Constraints Library, and information on binding constraints. Information on binding constraints is also published with each Market Schedule and as part of ST-PASA and MT-PASA.

AEMO also publishes an annual report analysing and describing network congestion for the previous Capacity Year and outlining expected power system changes which could affect future network congestion such as new connections, network augmentation, and Facility retirements.

6.6.4 Oversight

Constraint Equations are a critical driver of both PSS and market costs. PSS could be threatened by inaccurate Limit Advice or Constraint Equation construction. On the other hand, using overly conservative Constraint Equations in the Dispatch Algorithm could increase market prices, placing unnecessary costs on Market Participants through inefficient market outcomes or additional network investment to alleviate perceived constraints.

At least every three years, the ERA reviews the effectiveness of the process used to develop Limit Advice and Constraint Equations, including specific focus on:

- How the Network Operator prepares Limit Advice, including whether the risk margins it applies are appropriate.
- How AEMO formulates Constraint Equations, including whether the Operating Margins it applies are appropriate.
- How AEMO applies Constraint Equations.
- Whether information about constraints is published as required.

Rule Participants and other interested stakeholders can provide input to the ERA's review, including requesting an earlier review if necessary.

[69] More information on the Congestion Information can be found in clause 2.27B of the WEM Rules.

7 The Reserve Capacity Mechanism

The rules discussed in this section are currently under review by EPWA as part of the RCM review. This section will be revised in a future release as more information becomes available.

7.1 Overview

The purpose of the RCM is to ensure the SWIS has adequate installed capacity available from generation systems, Electric Storage Resources, and DSM options at all times to:

- Meet one-in-10-year peak demand plus a margin to cover generation Outages while maintaining minimum requirements to maintain system frequency; and
- Ensure energy shortfalls are limited to a defined threshold.

Market Participants providing Reserve Capacity may be able to fund all or part of their fixed capital costs through the RCM (while recovering the remainder and variable costs through the energy and ESS markets).

AEMO administers the RCM by determining the annual Reserve Capacity Requirement which is published in the annual Electricity Statement of Opportunities (ESOO) report that considers the capacity requirements of the SWIS for the next 10 years. Each Market Participant who purchases energy from the WEM is allocated a share of the Reserve Capacity Requirement, called its IRCR, and is required to secure Capacity Credits to cover that requirement. A Capacity Credit is a notional construct under the WEM Rules representing capacity from a Facility that has been certified by AEMO. Each Capacity Credit is equivalent to 1 MW of Reserve Capacity. Certified Facilities are assigned Capacity Credits based on:

- Their capability to provide capacity or their CRC (as determined during certification); and
- Their network access as determined by the Network Access Quantity (NAQ) calculated by AEMO.

Market Participants can procure Capacity Credits bilaterally from Capacity Credit suppliers. AEMO purchases any Capacity Credits which are not bilaterally traded. If a participant does not bilaterally purchase enough Capacity Credits to cover its IRCR, it will be charged for the shortfall through the settlement process, at a cost reflecting the price paid by AEMO to acquire them. When Capacity Credits are issued in excess of the Reserve Capacity Requirement, the cost of acquiring the surplus Capacity Credits is allocated to Market Participants in proportion to their IRCRs.

7.2 The Reserve Capacity Cycle

The Reserve Capacity Cycle takes place over four calendar years, with Reserve Capacity being procured two years before the relevant obligations take effect.

Figure 10 and Figure 11 illustrate a simplified version of the Reserve Capacity Cycle, denoting key events in the cycle[70].

Figure 10 Reserve Capacity Cycle timeline

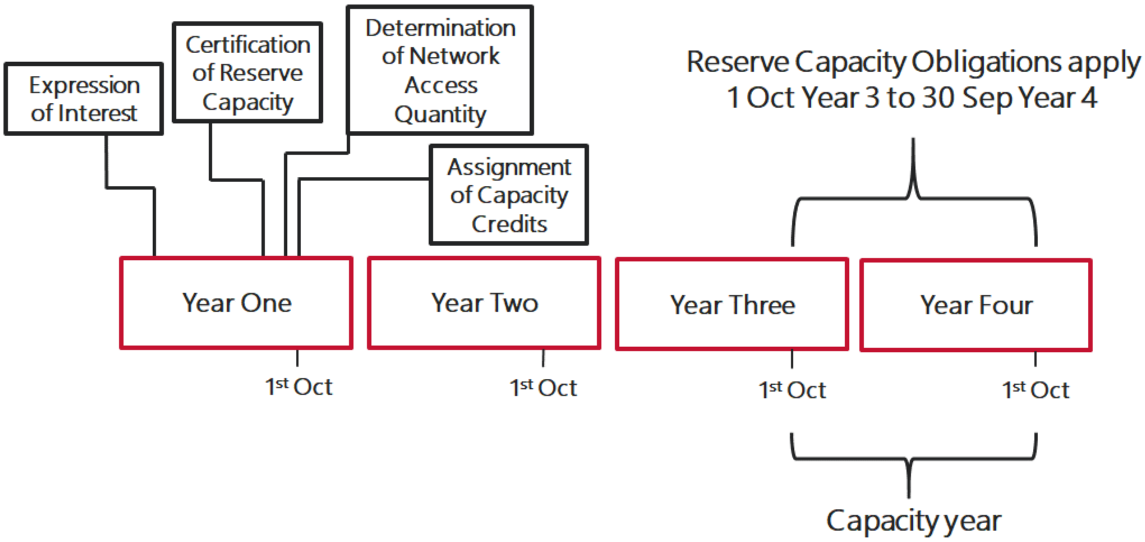
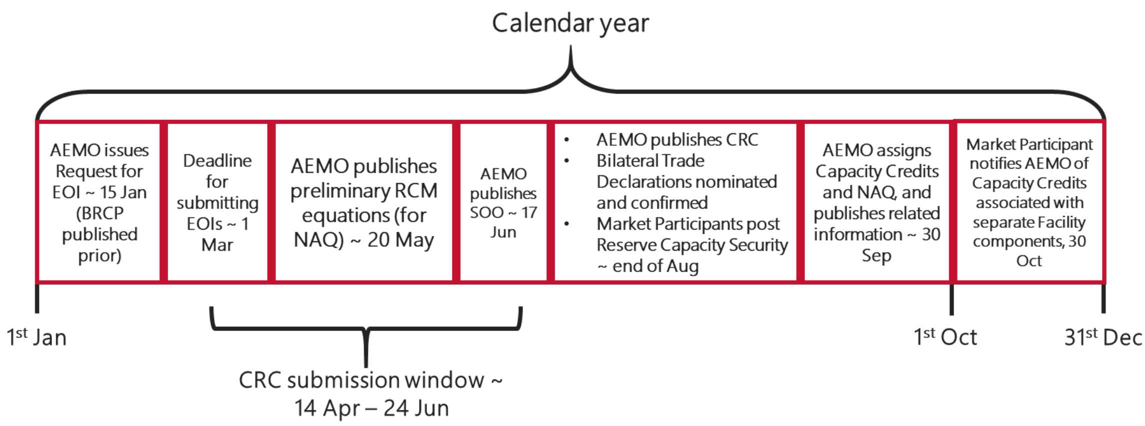


Figure 11 Reserve Capacity timeline for Year 1



7.3 Information gathering and long-term planning

Before the Reserve Capacity certification and the Capacity Credit assignment processes can commence, AEMO undertakes various planning and preparatory processes to ensure it has all the information it requires to administer the RCM for the relevant Reserve Capacity Cycle.

[70] Detailed timing information is covered in clause 4.1 of the WEM Rules.

7.3.1 Expressions of Interest for new capacity and retirement notifications[71]

> *The rules in this section are subject to an upcoming change to remove the mandatory requirement to submit Expressions of Interest for new capacity.*

Any Market Participant who has not previously been assigned Capacity Credits in respect of a Facility (for example, a new Facility or an upgrade to an existing Facility) and wishes to participate in the RCM for a given Reserve Capacity Cycle must submit an EOI to AEMO, providing information about the capacity it wishes to make available. This information is critical as it is an input into the RCM Constraint Equations developed by AEMO, which feeds into the NAQ calculation, which ultimately limits how many Capacity Credits a Market Participant is entitled to given Network Constraints.

Market Participants must notify AEMO of retirements plans at least three years before the planned retirement[72], so AEMO can incorporate the resulting additional network access into the NAQ determination.

7.3.2 Electricity Statement of Opportunities report

Each year AEMO conducts the LT-PASA to forecast capacity requirements for the relevant Reserve Capacity Cycle. As part of the LT-PASA, AEMO prepares the ESOO, outlining projected capacity requirements (or Reserve Capacity Target) for the SWIS and projected Capacity Shortfalls for each of the next ten years. This report indicates opportunities for supply and demand augmentations that would improve the adequacy and security of the power system. AEMO does not consider transmission planning, as this is addressed by Network Operators and the Coordinator through the WoSP and the TSP; however, the ESOO may make use of transmission planning information provided by Network Operators through the TSP and other resources.

The ESOO is released in June each year and is used to set the Reserve Capacity Requirement for the Capacity Year starting in October two years later (that is, the year starting 1 October of Year 3 of the relevant Reserve Capacity Cycle).

To develop the ESOO, AEMO is empowered to request information from Rule Participants regarding their expected future system usage and available energy supply, demand side and transmission capacities. AEMO also takes into account probable new projects where appropriate.

AEMO determines the capacity required in each Capacity Year that should be sufficient to:

- Meet the forecast peak demand, plus a reserve margin equal to the greater of 7.6% of peak demand or the capacity of the largest generating unit, while being able to maintain normal frequency control. Peak demand forecasts are calculated to a probability level that the forecast would not be expected to be exceeded in more than one year out of 10.
- Limit expected energy shortfalls to 0.002% of annual energy consumption, including the effects of transmission losses and Network Constraints.

Generation systems, Electric Storage Resources, and demand-side options are considered in meeting the above requirements:

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[71] The EOI process and the process for notifying retirements are set out in clauses 4.2 to 4.4A of the WEM Rules.

[72] The three-year window can be shortened in extenuating circumstances; for example, where a Market Participant becomes insolvent, suffers a force majeure incident, or must retire a plant for commercial reasons.

- Capacity from generation systems[73] is considered Availability Class 1 capacity. This capacity is available in real time throughout the year (subject to factors such as fuel availability and intermittency).
- Capacity from DSPs and (standalone) Electric Storage Resources is considered Availability Class 2 capacity. This capacity is called on only when Availability Class 1 options have been exhausted and is not expected to be always available. DSP capacity requires a notice period prior to dispatch.

In addition to determining the Reserve Capacity Requirement, AEMO also determines the minimum amount of Availability Class 1 capacity required to maintain PSS and PSR, so that any Availability Class 2 capacity procured for Reserve Capacity reasons is not so large as to undermine the ability of AEMO to maintain PSS and PSR[74].

7.4 Capacity assignment

7.4.1 Certified Reserve Capacity[75]

Market Participants wanting to participate in a Reserve Capacity Cycle must undergo the certification process administered by AEMO, where they must submit information about (but not limited to) the technological characteristics and capabilities of their Facilities.

AEMO assesses applications for certification, and awards CRC to Facilities taking into account the type of technologies the Facility comprises as well as other considerations such as firmness of commitment of new Facilities[76], fuel availability, historical Forced Outages, Facility DSOC, and embedded or Parasitic Loads served by the Facility.

The amount of CRC depends largely on the Facility's capability to generate during peak load intervals. Hence:

- The Non-Intermittent Generating Systems at a Facility are awarded capacity based on how much energy they can send out at 41 degrees Celsius.
- Intermittent Generating Systems at a Facility are awarded capacity based the Relevant Level Methodology, which allocates capacity based on historical Intermittent Generating System output during Trading Intervals when surplus capacity is the lowest, and therefore the system is under greatest stress.
- Electric Storage Resources at a Facility are awarded capacity based on a Linearly De-rating Method which allocates capacity based the ability of an Electric Storage Resource to sustain output during The Electric Storage Resource Obligations Intervals (eight consecutive Trading Intervals) during a Trading Day[77], given their storage (MWh) capability and capacity (MW). The Linearly Derating Method is set out in the Certification WEM Procedure[78]. AEMO determines an amount of CRC to assign to an Electric Storage Resource based on the relevant Market Participant's declaration of maximum sent out capacity at 41ºC (net of embedded loads), which AEMO may derate taking into account the following factors:
  - Forecast degradation rates (as specified in manufacturer's data or in an independent engineer's report)

[73] This includes hybrid Facilities comprising generation systems paired with Electric Storage Resources.

[74] More information on the LT-PASA process and ESOO is available in clause 4.5 of the WEM Rules.

[75] Detailed information requirements and the process used by AEMO to certify capacity is covered in clause 4.9 to 4.11 of the WEM Rules.

[76] For example, by considering whether access contracts exist, and whether environmental permits have been obtained.

[77] Refer to WEM Procedure: Electric Storage Resource Obligation Intervals (electric-storage-resource-obligation-intervals-wem-procedure.pdf (aemo.com.au))

[78] See WEM Procedure: Certification of Reserve Capacity

  - Historical Sent-Out Metered Schedules or Facility Sub-Metering data from the previous 12 months demonstrating the Electric Storage Resource's discharge capability.
  - Other information provided by the Market Participant as part of the certification process, or any information AEMO considers relevant.
- DSPs are awarded capacity based on the amount of load they can curtail or able to curtail via contractual arrangements where they do not own, operate, or control the Non-Dispatchable Loads which their Facility is associated with. Capacity is awarded based on the DSP's ability to curtail load relative to its Relevant Demand, which is indicative of the consumption of its Associated Loads during Peak Trading Intervals[79].

Hybrid Facilities can comprise two or more of the Facility Technology Types listed above. For example, a Facility may comprise an Intermittent Generating System and an Electric Storage Resource. For this reason, a component-based certification approach is used, awarding CRC for each Separately Certified Component.

Smaller Facilities that register in the Non-Scheduled Facility Class are assigned capacity based on the Relevant Level Method or, if they contain Electric Storage Resources only and have been in operation for under five years, the Linear De-rating Method.

Market Participants can also apply for Conditional Certification or Early Certified Reserve Capacity some years before the relevant Reserve Capacity Cycle. The information required is the same as for the normal certification processes. Conditional certification provides potential investors with greater certainty in securing financing and when negotiating Bilateral Contracts. Similarly, the Early Certified Reserve Capacity process allows new projects with long lead times to secure capacity earlier, providing greater certainty for investors and financiers.

Early Certified Reserve Capacity is granted for the applicable Capacity Year without the requirement to re-apply for CRC during the usual certification window, although the application will be considered the next time AEMO runs the CRC process. If the Market Participant applies for final certification, and no information upon which the Conditional Certification was based has changed, and all approvals required normally for certification are provided, then it will automatically be certified.

Once AEMO has awarded CRC to a Facility, the relevant Market Participant must notify AEMO how much of that capacity it intends to make available for trade, either by retaining the capacity to cover its own Reserve Capacity funding costs (see Section 7.8) or through contracts with other Market Participants. Any CRC that is not made available for bilateral trade ceases to be considered as CRC and is not considered in the NAQ Model (see Section 7.4.2) or the subsequent assignment of Capacity Credits (see Section 7.4.3).

7.4.2 Network Access Quantities[80]

The NAQ is a new design element of the RCM assigned to a Facility and measured in megawatts (MW). It is an instrument that establishes a preferential right to receive Capacity Credits. A Facility that has been assigned a NAQ will receive Capacity Credits up to the amount of the NAQ that it holds ahead of other Facilities that do not hold NAQ. It provides a cap on the amount of Capacity Credits a Facility can receive based on the available network capacity at the relevant connection point. The NAQ is assigned to a Facility up to the Facility's CRC at

[79] The Relevant Demand of a DSP represents the lesser of its historical 95% probability of exceedance (POE) consumption during Peak Trading Intervals, and the aggregate IRCRs of its Associated Loads (see Section 7.8 for an explanation of IRCRs).

[80] Rules on NAQ determination are set out in clause 4.15 of the WEM Rules, with the detailed methodology described in Appendix 3 of the WEM Rules.

peak times or other periods of Low Reserve, subject to available network capacity, ensuring that Capacity Credits are assigned based on the transfer capability of the Network.

AEMO determines a NAQ for each Facility that has been awarded CRC by considering the delivery capability of Facilities during peak demand intervals under a variety of dispatch Scenarios in the presence of Network Constraints. To facilitate the determination of NAQs, the Network Operator provides Limit Advice to AEMO, which AEMO uses to develop RCM Constraint Equations to model the Facility dispatch Scenarios (See Section 6.6).

The NAQ establishes de-facto capacity rights for incumbent Facilities. That is, Facilities that held Capacity Credits in a previous cycle are assigned a NAQ first (by assuming that only these Facilities are injecting; i.e. only incumbent Facilities are included in the first iteration of the NAQ calculation). This quantity cannot be reduced in subsequent cycles unless they retire or their CRC is reduced (see below).

Once a Facility has been assigned a NAQ, it retains the de-facto capacity right in perpetuity, unless:

- The Facility retires; or
- The Facility is awarded a lower amount of CRC in a subsequent cycle (e.g., due to performance issues). If this happens, then the relevant Facility's NAQ is reduced to match its CRC. However, if the Facility is a Semi-Scheduled Facility or a Non-Scheduled Facility, and therefore likely to be impacted by fluctuations in the Relevant Level Methodology, they are prioritised before new Facilities and Upgrades in subsequent cycles if their CRC increases; or
- There are 'organic' changes in the network that reduce its transfer capability, thereby reducing the Facility's ability to inject. If this happens, the relevant Facility's NAQ is reduced accordingly. However, they are prioritised before new Facilities and Upgrades in subsequent cycles if their CRC does not decrease.

This means, that in each Reserve Capacity Cycle, new Facilities (or existing Facilities in respect of their upgrades) can only access:

- The residual capacity in the relevant part of the Network; or
- Network capacity which is funded by the relevant Market Participant; or
- Any additional capacity that becomes available as a result of incumbent Facilities retiring or being awarded less CRC.

New Facilities that the responsible Market Participant has nominated to be Fixed Price Facilities (see Section 7.6) are prioritised below Facilities that have accepted the floating Reserve Capacity Price when allocating any residual/additional capacity. Furthermore, Fixed Price Facilities can only be allocated NAQs up to the Reserve Capacity Requirement (as determined in the ESOO); hence, even if the residual capacity on the network would enable further allocation, Fixed Price Facilities have their allocation capped.

Facilities which have committed to fund deep connection costs for network augmentation to the shared network (known as a Network Augmentation Funding Facilities) are prioritised ahead of other new Facilities or upgrades. A Network Augmentation Funding Facility can be allocated a NAQ up to the amount that their funding increases the capacity of the shared network by, but only where it does not reduce the NAQ of any incumbent Facility that has previously been assigned a NAQ.

Facilities going through Early Certification of Reserve Capacity are assigned an Indicative NAQ in intervening Reserve Capacity Cycles, before being assigned a Final NAQ (which will form the basis of Capacity Credit assignment) in the cycle in which the Facility will deliver its capacity).

7.4.3 Capacity Credits and obligations

Assigning Capacity Credits

Once Facilities have been assigned NAQs, AEMO can assign them Capacity Credits, which indicates the amount of capacity that Facility is obliged to provide, and for which they will be compensated. The amount of Capacity Credits assigned by AEMO to a Facility is dependent on the amount of CRC awarded, its NAQ, and whether it was awarded capacity prior to the 2022 cycle.

Specifically:

- Incumbent Facilities that were not under a Generator Interim Access[81] arrangement prior to the 2022 cycle and have been assigned Capacity Credits prior to the 2022 cycle have their access rights 'uplifted' above their assigned NAQ to reflect historical capacity rights. Hence, they are assigned:
  - Their NAQ; plus
  - The difference between their Initial NAQ (historical Capacity Credit assignment) and the NAQ determined for the 2022 Reserve Capacity Cycle.
- Incumbent Facilities that were under a Generator Interim Access arrangement prior to the 2022 cycle, new Facilities, or upgrades to incumbent Facilities are assigned Capacity Credits equal to their NAQ (noting that a NAQ cannot exceed the amount of CRC awarded).

For the purposes of setting RCOQs and calculating refunds (see below), AEMO must be able to associate assigned Capacity Credits with each Separately Certified Component of a hybrid Facility. If AEMO has assigned a quantity of Capacity Credits to a hybrid Facility that is less than the amount of CRC awarded to that Facility (e.g. due to a lower NAQ allocation, or because the participant did not wish to trade as portion of their capacity bilaterally), then the relevant Market Participant must notify AEMO how they wish to apportion their Capacity Credit assignments across the various Separately Certified Components that comprise their hybrid Facility. Otherwise, AEMO uses the amount of CRC assigned to each Separately Certified Component for the purposes of setting RCOQs.

Reserve Capacity Obligations

Market Participants who have been assigned Capacity Credits for their Facilities have certain obligations which apply between 1 October Year 3 and 1 October Year 4 of a Reserve Capacity Cycle.

The key requirement is that Facilities have an obligation to offer their capacity into the STEM and RTM; if they do not, they are liable to pay refunds (see below). The minimum quantity that they must offer is their RCOQ. As with CRC, RCOQs vary depending on the Facility's technological characteristics and capabilities[82].

- The Intermittent Generating System component of a Facility has an RCOQ of zero in all Trading Intervals; this reflects the unpredictability of their output.

[81] The Generator Interim Access arrangement was a temporary measure used to curtail the Injection of new Facilities building in congested areas of the SWIS. It was intended as a stop gap measure until Security Constrained Economic Dispatch and Constrained Access were implemented.

[82] See also clause 4.12 of the WEM Rules.

- The Electric Storage Resource Component of a Facility has an RCOQ equal to the quantity of Capacity Credits assigned, but only during the Electric Storage Resource Obligation Intervals (eight consecutive Trading Intervals within a Trading Day) and only if the temperature is 41 degrees Celsius or below.
  - The RCOQ of the storage component is zero during any interval that is not an Electric Storage Resource Obligation Interval.
  - If the temperature exceeds 41 degrees Celsius during an Electric Storage Resource Obligation Interval, the RCOQ is derated by the ratio of the storage component's capability to discharge at 45 degrees Celsius to its ability to discharge at 41 degrees Celsius.
- The Non-Intermittent Generating System component of a Facility has an RCOQ equal to the quantity of Capacity Credits assigned in all Trading Intervals if the temperature is at or below 41 degrees Celsius. If the temperature exceeds 41 degrees Celsius, the RCOQ is derated by the ratio of the Non-Intermittent Generating System's capability to generate at 45 degrees Celsius to its ability to generate at 41 degrees Celsius.
- DSPs have an RCOQ equal to the quantity of Capacity Credits assigned to the Facility; however, that RCOQ can be reduced to zero in some circumstances:
  - If the Facility has been dispatched for the maximum allowable number of hours in a Trading Day, then the RCOQ is zero for the rest of that Trading Day.
  - If the Facility has been dispatched for the maximum allowable number of hours in a year, then the RCOQ is zero for the rest of that Capacity Year.
- The RCOQ of the Facility in its entirety, is the sum of the RCOQ of the Separately Certified Components in each Trading Interval.
- Non-Scheduled Facilities have an RCOQ of zero irrespective of the technologies contained in the Facility.

Market Participants with Capacity Credits must also:

- Participate in Outage planning process (see Section 6.5).
- Comply with AEMO's performance monitoring of Reserve Capacity Obligations.
- Comply with Reserve Capacity Test requirements (see Section 7.10).

Reserve Capacity refunds

Market Participants who have been assigned Capacity Credits must refund their capacity payments if they fail to meet availability requirements (e.g., due to a Forced Outage, a failure to offer sufficient capacity, or not reoffering capacity as In-Service when it has been offered as Available and is forecast to be cleared by the Dispatch Algorithm)[83]. A Dynamic Refund Factor, or multiplier, is used to ensure Market Participants refund more than they otherwise would have been paid in a Peak Trading Interval; this is to encourage compliance with RCOQs when the capacity margin is tight. The magnitude of the refund factor depends on the spare capacity or reserve margin during the Trading Interval where the relevant Facility was unavailable. Refund factors are inversely proportional to the amount of spare capacity and can be up to six times (but no less than 0.25 times) the capacity payment for a Trading Interval. Hence, the tighter the reserve margin, the higher the multiplier (and therefore the refund). The

[83] See Section 8.2 on RTM Submissions for a description of In-Service Capacity.

dynamic nature of the refund factor encourages Market Participants to ensure they meet their RCOQs in periods when demand is high.

Total refunds paid by a Market Participant holding Capacity Credit are capped to ensure it does not refund more during a year than it received in capacity payments in that year. Reserve Capacity refunds are intended to discourage non-compliance in a Trading Interval while capping the risk if non-compliance over a long timeframe is unavoidable.

Refunds collected by AEMO are distributed to capacity providers in proportion to the Forced Outage adjusted RCOQ of their Facilities[84].

7.5 Reserve Capacity Security[85]

As a condition of certification of Facilities that have not yet been commissioned (or which have undergone significant maintenance or an upgrade), AEMO requires the payment of a Reserve Capacity Security. The Reserve Capacity Security is initially equal to 25% of the value of the annual payments the Facility would receive based on its Bilateral Trade Declarations and the BRCP. Once the Facility has been assigned Capacity Credits, a Market Participant can request that the security be recalculated to 25% of the value of the annual payments the Facility would receive based on its Capacity Credit assignment and the BRCP (see Section 7.6).

Market Participants must also submit Reserve Capacity Security in respect of any DSPs being certified; unlike other Facilities, Reserve Capacity Security must be submitted in respect of all DSPs (not just new or upgraded ones).

If a Market Participant fails to supply AEMO with Reserve Capacity Security by 25 August of Year 1 of the relevant Reserve Capacity Cycle, AEMO will cancel any CRC that has been awarded to the relevant Facility.

This security will be returned to the Market Participant:

- If the Facility fails to secure Capacity Credits; or
- When it first reaches an output level that fully satisfies its RCOQ.

If a Facility operates at a level equivalent to 90% of its Required Level[86] in any two Trading Intervals, or the participant provides AEMO with a report from an independent expert specifying that the Facility can operate at an equivalent level, then the security will be returned at the end of the year (provided AEMO is satisfied the Facility is in Commercial Operation). If these requirements are not met during the Capacity Year, then AEMO will draw down on the security and can use the funds to procure supplementary capacity (see Section 7.7).

[84] Detailed refund calculations are set out in clause 4.26 of the WEM Rules.

[85] See also clauses 4.13 and 4.13A of the WEM Rules.

[86] The Required Level for an energy producing Facility is component-dependent:

- A Non-Intermittent Generating System or Electric Storage Resource component must be able to output energy at a level that is at least equal to the MW quantity of Capacity Credits assigned to that component.
- An Intermittent Generating System component must be able to output energy at a level equal to its 5% POE level (as provided by the participant to AEMO during the certification process).

The Required Level for a DSP is indicated by its ability to curtail Withdrawal from its Relevant Demand by the quantity of Capacity Credits assigned.

If a Facility (other than a DSP) operates at a level equivalent to 100% of its Required Level in any two Trading Intervals during the relevant Capacity Year, then the relevant Market Participant may request its Reserve Capacity Security to be returned immediately.

Market Participants can apply to AEMO to have their Reserve Capacity Security returned or waived in respect of their DSPs. In deciding whether to return the security or waive the requirement, AEMO takes into account the nature of the Associated Loads and their historical performance with respect to Reserve Capacity Tests (see Section 7.10).

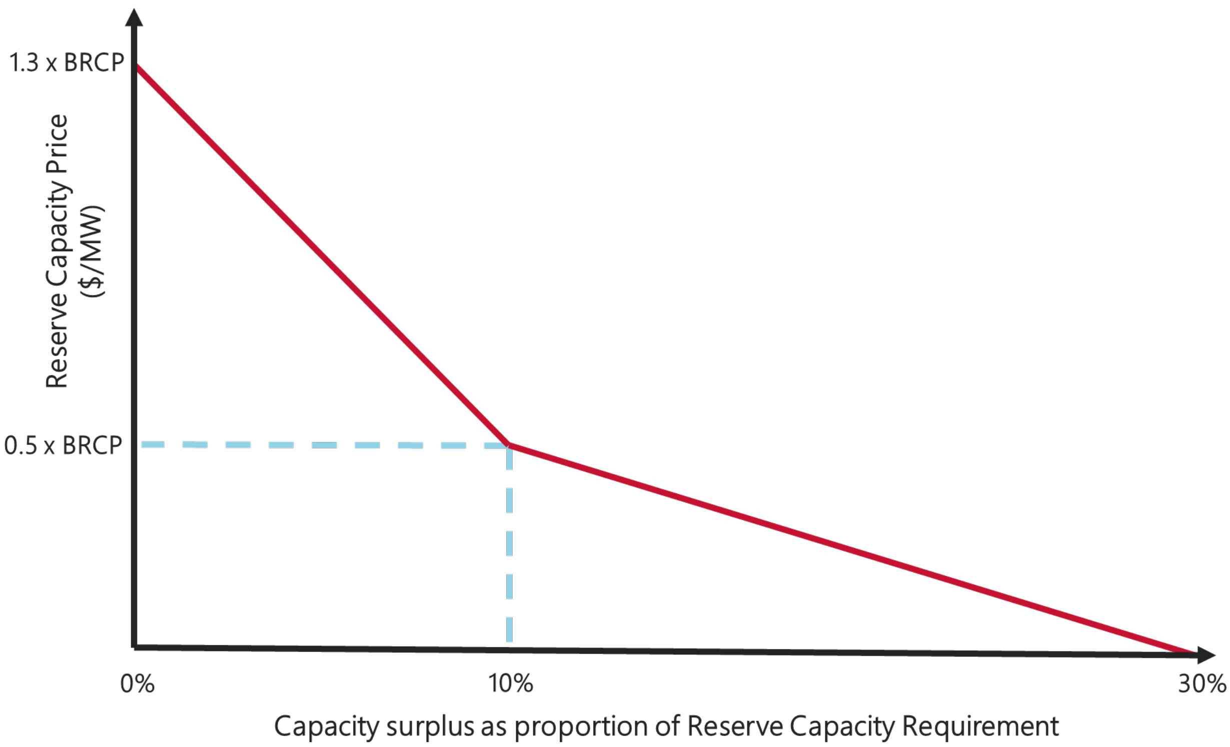
7.6 Reserve Capacity Prices

Reserve Capacity Prices are calculated annually and are pegged to the BRCP. The BRCP reflects the Long Run Marginal Cost of a 40 MW OCGT and is set annually by the ERA[87].

The Reserve Capacity Price is a function of the BRCP, and the extent to which there is surplus capacity in the WEM as illustrated in Figure 12. In particular:

- If there is no surplus capacity, the Reserve Capacity Price is set to 130% of the BRCP.
- If surplus capacity is 10%[88], the Reserve Capacity Price is set to 50% of the BRCP.
- If the surplus capacity is 30% or higher, the Reserve Capacity Price is zero.

Figure 12 Reserve Capacity Price curve



[87] The rules for determining and reviewing the BRCP are set out in clause 4.16, while Reserve Capacity Pricing Rules are set out in clause 4.29 of the WEM Rules.

[88] Deemed to be the level of surplus at which no capacity should enter the market (from an economic perspective).

Reserve Capacity Prices for a given Reserve Capacity Cycle apply between 1 October Year 3 and 30 September Year 4 of a cycle.

Transitional arrangements are in place for Facilities that were assigned Capacity Credits in the 2018 Reserve Capacity Cycle:

- If the Reserve Capacity Price for a subsequent cycle is below a defined floor, these Facilities are paid the price floor value.
- If the Reserve Capacity Price for a subsequent cycle is above a defined cap, these Facilities are paid the price cap value.
- The price floor and cap were respectively set at $114,000/MW and $140,000/MW for the 2019 Reserve Capacity Cycle and are inflated by the Consumer Price Index for subsequent cycles.
- These transitional arrangements are in place up until the 2028 Reserve Capacity Cycle.

Market Participants seeking price certainty can opt to nominate themselves to be a Fixed Price Facility (during the certification process). Fixed Price Facility prices are pegged to the Reserve Capacity Price of the first Reserve Capacity Cycle in which they make their capacity available; thereafter, the Reserve Capacity Price from that first cycle is increased by the Consumer Price Index for each subsequent cycle. Fixed Prices are valid for five years.

7.7 Supplementary capacity[89]

If AEMO considers at any time during the six months prior to the Capacity Year that there will be insufficient capacity available to maintain PSS and PSR, it may acquire supplementary capacity from Eligible Services which include:

- Demand-side and Energy Producing System options that are not currently Registered Facilities; and
- Existing demand-side[90] and Energy Producing System options, but only to the extent that the relevant Market Participant:
  - Does not hold Capacity Credits with respect to the relevant capacity in the current Capacity Year; or
  - Has not previously held Capacity Credits with respect to the relevant capacity in the current Capacity Year; or
  - Has not previously held Capacity Credits with respect to the relevant capacity in the current and previous Capacity Years.

The latter two requirements on existing resources ensures that existing Market Participants do not withhold capacity that they would otherwise offer through the RCM.

AEMO may conduct an EOI process to gauge what Eligible Services are available in the market. The EOI notice must include (but is not limited to):

- AEMO's preliminary estimate of the quantity of Supplementary capacity needed.

[89] See also clause 4.24 of the WEM Rules.

[90] Demand-side resources that have previously failed to meet their Reserve Capacity Obligations during the current and previous Capacity Year are ineligible to provide supplementary capacity.

- AEMO's preliminary estimate of the timing (day of year) and duration (of response) needed.
- Duration of the contract which must not exceed the length of the Hot Season.
- AEMO's preliminary estimate of contract value (noting that Supplementary Contracts are subject to alternative pricing arrangements).

If the expected shortfall is more than 12 weeks away, then AEMO must run a tender process to acquire the supplementary capacity needed; however, if the projected Capacity Shortfall is less than 12 weeks from when AEMO becomes aware of the shortfall, AEMO may enter directly into negotiations with potential suppliers.

Potential providers must specify the location of their capacity, availability restrictions on their capacity, an availability cost, and a usage cost reflecting costs directly incurred (e.g., a stand-by generator's fuel cost). AEMO must select offers to minimise the expected cost, based on the expected number of hours for which the supplementary capacity is required.

Selected providers will have their rights and obligations governed by a contract with AEMO, rather than by the WEM Rules. This allows supplementary capacity to be provided by parties that are not Rule Participants. The Supplementary Capacity Contract includes provisions around verification and testing, capacity adjustment, payment and refunds. AEMO must develop a standard form Supplementary Capacity Contract for this purpose; however, AEMO can negotiate variations to the standard conditions where this is required to secure sufficient capacity or to minimise costs.

The costs of supplementary capacity are recovered through the Shared Reserve Capacity Cost allocation (see Section 7.8.2).

7.8 Funding Reserve Capacity

7.8.1 Individual Reserve Capacity Requirements

One of the key market parameters used to allocate the cost of procuring Reserve Capacity is a Market Participant's IRCR.

AEMO calculates the IRCR for each Market Participant whose Facilities consume energy (including Loads, Facilities containing Loads, and energy producing Facilities that have auxiliary Load). A Market Participant's IRCR is largely based on its historical median consumption during the 12 Trading Intervals with the highest demand in the preceding Hot Season[91]. Hence, the higher a Participant's consumption during peak intervals, the higher its contribution towards funding Reserve Capacity[92].

Even though the IRCR is largely based on historical consumption in the preceding Hot Season, AEMO calculates the IRCR on a monthly basis to account for end-use customers shifting between retailers, new end-use customers entering the market, and existing end-use customers leaving the market.

A Market Participant's IRCR equals its contribution to system peak load, plus an additional reserve margin: approximately 30% for Loads which are temperature-dependent and 10% for Loads which are not temperature-dependent. Some Intermittent Loads are a special (grandfathered) case and are explained further below.

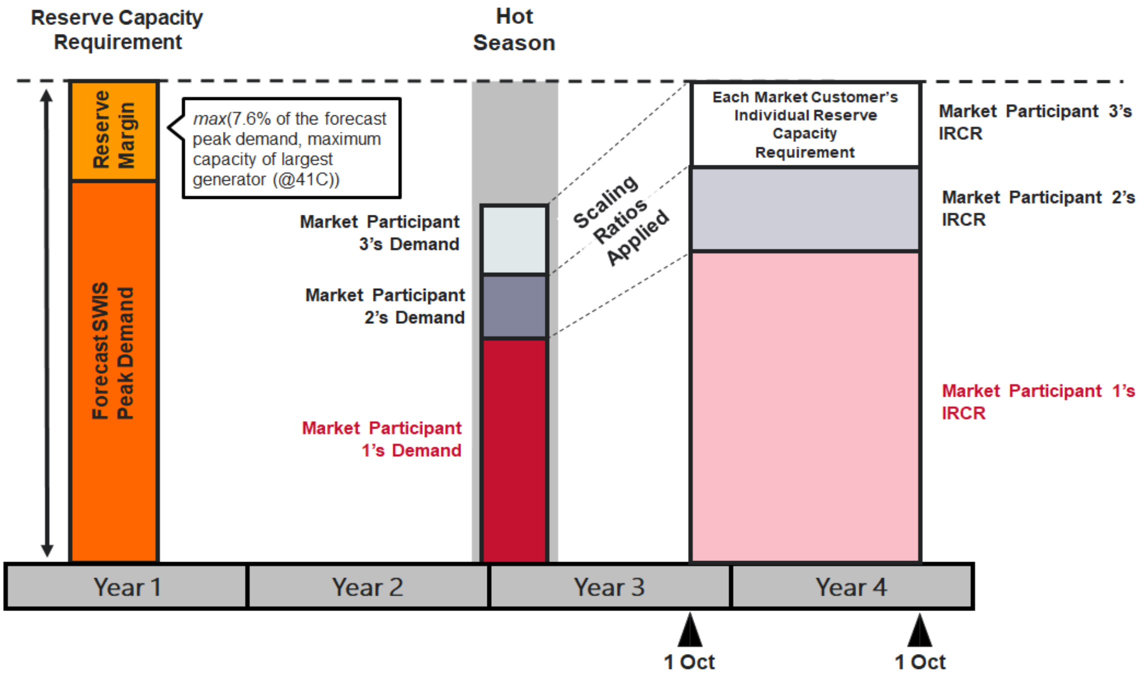
[91] The Hot Season spans 1 October of a given year to 31 March of the following year.

[92] The calculation of the IRCR of a Facility containing an Electric Storage Resource, will exclude consumptions from the storage system in any Trading Intervals in which it has received a Direction from AEMO.

While the IRCR contribution of each Market Participant changes each month, these quantities are scaled to ensure the total quantity sums to the Reserve Capacity Requirement (or the total number of Capacity Credits assigned to Market Participants, if this is lower).

Figure 13 is a simplified overview of the IRCR calculation assuming (hypothetically) that there are three Market Participants that capacity costs are to be recovered from[93].

Figure 13 Example IRCR calculation



7.8.2 Allocating Reserve Capacity Costs

Market Participants who do not hold enough Capacity Credits for a given Trading Month will be required to fund the Targeted Reserve Capacity Cost. This is the cost of Capacity Credits procured by AEMO up to the Reserve Capacity Requirement. The Targeted Reserve Capacity Cost is allocated in proportion to each Market Participant's Capacity Credit shortfall (relative to its IRCR). The purpose of this Targeted Reserve Capacity Cost is to provide an incentive for Market Participants to contract bilaterally for capacity.

Where AEMO has procured Capacity Credits in excess of the Reserve Capacity Requirement, then the cost of the surplus Capacity Credits is recovered via the Shared Reserve Capacity Cost. This cost comprises:

- The cost of Capacity Credits procured by AEMO that are surplus to the requirements of the market (that is, over and above the Reserve Capacity Requirement);
- Plus the cost of supplementary capacity payments;
- Less any refunds paid by grandfathered Intermittent Loads (see below);
- Less any revenue beyond that required to fund supplementary capacity payments earned by AEMO where it has claimed Reserve Capacity Security posted by a provider of Capacity Credits that fails to ever satisfy its obligations.

[93] The detailed methodology for calculating IRCR is described in Appendix 5 of the WEM Rules.

The Shared Reserve Capacity Cost is allocated between all Market Participants in proportion to their IRCRs. This approach is used because the components of the Shared Reserve Capacity Cost cannot meaningfully be assigned to any individual Market Participant[94].

7.8.3 Intermittent Loads[95]

Intermittent Loads registered after the beginning of the new market fund Reserve Capacity in the same way as any other Load: through the IRCR calculations.

Intermittent Loads which existed at the beginning of the new market have grandfathered arrangements with respect to funding Reserve Capacity. These Intermittent Loads are not allocated costs based on IRCRs but are instead required to pay refunds if their behind-the-fence Energy Producing System is on Outage.

7.9 Capacity Credit Allocation process[96]

Capacity Credits that a Market Participant has traded bilaterally with another Market Participant are accounted for in settlement via the Capacity Credit Allocation process.

Market Participants who are recipients of a Capacity Credit Allocation have reduced exposure to Reserve Capacity Costs (as their received allocations are netted off their IRCRs when calculating Targeted Reserve Capacity Cost shares); this reduced exposure also flows through to lower Prudential Requirements.

Market Participants who hold Capacity Credits must submit their Capacity Credit Allocations to AEMO for a Trading Day (no later than 5:00 pm of the previous day (Scheduling Day)), identifying the Facilities from which they are allocating Capacity Credits, along with the recipient of the allocation and the quantity being allocated.

AEMO reviews Capacity Credit Allocations and accepts those that meet the format requirements as long as the submitting participant has not allocated more Capacity Credits than it holds. AEMO can reject submissions where Capacity Credits have been over-allocated, and Market Participants can re-submit their allocations if it is before 5:00 pm of the relevant Scheduling Day.

7.10 Performance monitoring and Reserve Capacity Testing[97]

Scheduled Facilities and Semi-Scheduled Facilities assigned Capacity Credits must undergo testing throughout the year to prove they are able to output or curtail energy at their Required Level (see Section 7.5).

Reserve Capacity Testing is component based, and as such the requirements vary depending on the technology types contained within a Facility:

- Non-Intermittent Generating System components of a Facility are tested twice per year (once in summer and once in winter). The system must demonstrate the ability to meet its Required Level for two consecutive Trading Intervals at least once during each testing period.

[94] The rules governing allocation of Reserve Capacity Costs is set out in clause 4.28 of the WEM Rules.

[95] See also clause 4.28A of the WEM Rules.

[96] See also clause 4.14 of the WEM Rules.

[97] See also clauses 4.25, 4.25A and 4.27 of the WEM Rules.

- Electric Storage Resource components of a Facility are tested twice per year (once in summer and once in winter). The system must demonstrate the ability to meet its Required Level at least once during each testing period. Electric Storage Resources are subject to four continuous hours of testing to verify that they can be available continuously during the Electric Storage Resource Obligation Intervals.
- Intermittent Generating Systems are not tested as they have zero RCOQ.

In the first instance, AEMO would rely on historical meter data to confirm whether a Facility or Separately Certified Component has met the requirements above. The testing approach adopted by AEMO varies depending on whether a Facility is required to install Facility Sub-Metering[98]:

- Traditional non-hybrid Facilities that are not required to install Facility Sub-Metering are tested using Meter Data Submissions (i.e., meter data that is derived from the interval meter used for settlement).
- Hybrid Facilities that are required to install Facility Sub-Metering at tested using meter data derived from the Facility Sub-Metering of the relevant components being tested.

AEMO may Test Facilities or Separately Certified Components based on observation, if:

- A Market Participant fails to provide AEMO with Facility Sub-Metering data where relevant.
- Historical meter data indicate the Facility or Separately Certified Component did not meet the requirements above.
- AEMO has to retest a Facility or a Separately Certified Component because it has failed a previous Test by observation.

AEMO determines whether Facilities or Separately Certified Components have passed tests based on observation using, respectively, Meter Data Submissions and Facility Sub-Metering data. AEMO must reduce a Facility or Separately Certified Component's Capacity Credits if it fails a second test.

DSPs are tested as follows:

- The relevant Market Participant must undertake a Verification Test either within 20 Business Days of becoming a Registered Facility, or between 1 October and 30 November of Year 3 of the relevant Reserve Capacity Cycle. The DSP must be able to curtail a quantity no less than 10% of the Capacity Credit assigned to it.
- AEMO must conduct a Reserve Capacity Test for a DSP at least once during the Hot Season in which the DSP's Reserve Capacity Obligations apply. To pass the test, the DSP must be able to curtail Withdrawal from its Relevant Demand by the quantity of Capacity Credits assigned.

AEMO can retest a DSP that fails its Verification Test. However, a DSP can opt out of the re-test. If this happens, AEMO would reduce the Capacity Credits held by that DSP to reflects it Maximum Capability as demonstrated in the failed Verification Test).

As with other Facilities, if a DSP takes and fails a second test, AEMO will reduce its Capacity Credits accordingly.

[98] Hybrid Facilities comprising different technology types (e.g., wind and storage) will be required to install Facility Sub-Metering to facilitate Reserve Capacity Testing of Separately Certified Components. For Electric Storage Resources, the Facility Sub-Metering is also used to perform the Linearly Derated Method assessment during certification. The Facility Sub-Metering WEM Procedure (aemo.com.au) prescribes sub-metering requirements for such Facilities.

8 The Real-Time Market

8.1 Overview

The RTM enables secure, efficient dispatch of Registered Facilities in real time, allowing for participant energy production or consumption to differ from the day-ahead NCP in order to adjust for actual conditions and ESS market participation. This is achieved through:

- Security constrained economic dispatch of Facilities to match supply to demand in each five-minute Dispatch Interval while procuring sufficient FCESS to meet FOS.
- Determining Market Clearing Prices that can be used to settle participant differences from NCP, pay participants for providing FCESS, and recover the costs of FCESS provision.

Only participants that deviate from their NCP are exposed to Market Clearing Prices. Deviations can occur for physical reasons (e.g., demand differs from forecast, Forced Outages, or Network Constraints) or for market efficiency reasons (lower priced generation being dispatched in preference to higher priced generation).

All Scheduled Facilities and Semi-Scheduled Facilities must participate in the RTM. Facilities must meet technical and communication criteria to receive, confirm, and respond to electronic Dispatch Instructions from AEMO.

8.2 RTM Submissions[99]

Market Participants make RTM Submissions for each Dispatch Interval in the following seven days, representing the ability of each Registered Facility to provide energy and FCESS in the RTM. An RTM Submission is a series of Price-Quantity Pairs for a Dispatch Interval representing the quantities of service that the participant can make available, the prices at which it is prepared to do so, and the set of technical parameters which AEMO must respect (such as maximum ramp rates, ESS trapeziums (see Section 5.6.1) and Dispatch Inflexibility Profiles). Participants can submit a revised RTM Submission for a Dispatch Interval any time before Gate Closure for the interval[100].

Participants must ensure that their RTM Submissions accurately reflect:

- Their reasonable expectation of the capability of their Facilities to be dispatched in the RTM.
- Facility Outages, Commissioning Tests, and Reserve Capacity Tests.
- Intended commitment and decommitment.
  - Participants identify whether they intend to commit or decommit a Facility by submitting the quantity of Available Capacity and In-Service Capacity. In-Service Capacity represents the Facility capability (in MW or megawatt-seconds (MWs)) which the participant is currently expecting will be synchronised and ready to

[99] The detailed rules relating to RTM submissions are set out in clauses 7.4 and 7.4A of the WEM Rules.

[100] Under clause 7.4.35, Market Participants can revise submission after Gate Closure if the following apply:

- If a Semi-Scheduled or Non-Scheduled Facility's unconstrained forecasts change
- If the submission needs to be updated to reflect the impact of a Forced Outage
- If the Dispatch Inflexibility Profile of a Scheduled or Semi-Scheduled Facility needs to be updated to reflect a delayed start
- If a Market Participant expects it will be unable to comply with a Dispatch Instruction and indicates its Facility in Inflexible.

deliver service, while Available Capacity represents capability which the participant is not expecting to be synchronised, but which would be available if called on with sufficient notice (with the synchronisation time requirement included in the submission).

- Their own intermittent generation forecasts.
  - Participants must update RTM Submissions for Semi-Scheduled Facilities when their expected maximum output changes by more than a certain tolerance.

Participants must also take account of estimates of cleared energy and FCESS in AEMO's Market Schedules. If the Market Schedules project that a Facility will be dispatched for energy or FCESS in a way that is not physically feasible, the Participant will adjust its RTM Submission so that either the Facility is no longer forecast to be dispatched or the Facility is forecast to be dispatched to a feasible operating point. If Market Schedules project that a Facility will be dispatched for energy or FCESS, but the Participant's RTM Submission does not show the cleared capacity as In-Service Capacity, the Participant should either adjust its RTM Submission to offer the Facility with In-Service Capacity and prepare the Facility to be committed, or adjust its RTM Submission such that it is no longer forecast to be dispatched.

Participants holding Capacity Credits and SESSM Awards have more stringent requirements, as discussed in Section 7.4.3 and Section 6.3.4. In particular, if a Facility with Capacity Credits is offered as Available Capacity, and Market Schedules project that it will be dispatched for energy, the Participant must update its RTM Submission to show the cleared capacity as In-Service Capacity or face capacity refunds.

Prices in RTM Submissions:

- Are generally made by the Participant as at the network connection point for the Facility[101].
- Are adjusted by AEMO to be as at the Reference Node by applying the relevant Loss Factors for the network connection point.
- Increase monotonically with an increase in available quantity for each service.
- For energy, must be greater than or equal to the Energy Offer Price Floor and less than or equal to the Energy Offer Price Ceiling (after adjusting for Loss Factors).
- For Withdrawal, must be lower than any prices for Injection for the same Facility.

Participants must keep records of the underlying rationale for their RTM submissions, and the reasons for any updates within 48 hours of dispatch and any differences from Standing Data technical parameters.

'Fast Start' Facilities[102] can provide a Dispatch Inflexibility Profile in their RTM Submissions. AEMO Dispatch Instructions to Fast Start Facilities will respect this profile when the unit is starting. Participants can flag any Facility as 'Inflexible' in RTM Submissions, along with the level at which it can operate (and must lodge any related Forced Outage). AEMO will make reasonable endeavours to Dispatch Inflexible Facilities at the specified level.

Participants are not required to offer or schedule Withdrawal for Facilities containing an Intermittent Load.

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[101] Aggregated Facilities and DSPs offer as at the Electrical Location of their component Facilities or Associated Loads. The Electrical Location is the equivalent to Transmission Network Identifier (TNI) that the Facilities are connected to, or if embedded in the distribution network, the TNI to which the distribution network is connected. Such facilities must account for any Distribution Loss Factors in their submissions,

[102] Facilities which can:

- Synchronise and change their rate of Injection or Withdrawal within 30 minutes of receiving a Dispatch Instruction, and
- Shut down within 60 minutes of the initial Dispatch Instruction.

Participants must make RTM Submissions for Non-Scheduled Facilities reflecting their forecast Injection or Withdrawal and comprising a single Price-Quantity pair as follows:

- If the Market Participant intends for its Non-Scheduled Facility to be injecting, then it must offer the maximum intended Injection at the Energy Offer Price Floor;
- Otherwise, they must offer their intended maximum Withdrawal quantity at the Energy Offer Price Ceiling, once Loss Factor adjusted.

This helps improve accuracy of scheduling and dispatch.

Participants do not make RTM Submissions for DSPs, instead submitting Withdrawal Profiles setting out the estimated total Withdrawal by its Associated Loads in each Dispatch Interval. DSP Withdrawal Profiles must specify two quantities:

- A **DSP Unconstrained Withdrawal Quantity** which is the Market Participant's estimate of the average MW consumption of its DSP in a given Dispatch Interval assuming that DSP is not affected by any Dispatch Instruction or Reserve Capacity Test
- A **DSP Constrained Withdrawal Quantity** which adjusts the DSP Unconstrained Withdrawal Quantity to take into account the impact of any impending dispatch or Reserve Capacity Tests about which the Market Participant has been advised.

AEMO uses the DSP Withdrawal Profile information to adjust the Forecast Operational Demand used in the Dispatch Algorithm, so that dispatch is based on the best estimate of actual load. AEMO publishes two DSP Schedules (the DSP Pre-Dispatch Schedule and the DSP Week-Ahead Schedule) showing the available and expected curtailment for each Dispatch Interval in the schedule horizon. Most of the time, a Standing Withdrawal Profile will suffice, but if DSP dispatch looks likely, Participants need to update their Withdrawal Profiles.

8.3 The Dispatch Algorithm[103]

The Dispatch Algorithm is the core of the RTM. It is the method by which AEMO dispatches Facilities comprising Energy Producing Systems, Loads, and/or Electric Storage Resources to minimise the total cost of wholesale energy and FCESS, while explicitly accounting for the physical characteristics and security requirements of the SWIS. Finding the cheapest combination of supply involves optimising the dispatch of energy and ESS at all locations across the network, considering network losses and Constraints.

A Facility can provide either energy, Regulation, or Contingency Reserve from the same capacity. This means that if dispatch decisions for ESS are made separately from energy, there will be loss of efficiency, particularly where ESS requirements depend on energy output. Co-optimising dispatch of energy and ESS provides the mechanism to deliver the lowest-cost combination of dispatch from available Facilities. The Dispatch Algorithm dispatches energy and FCESS through a process called 'co-optimisation'.

Through co-optimisation, the Dispatch Algorithm can determine the overall least cost dispatch outcome for both energy and FCESS at the same time. Co-optimisation simplifies and de-risks the bidding process for Market Participants, allowing Facilities to simultaneously offer the same capacity into energy and multiple FCESS markets, while being commercially indifferent as to which services they are dispatched to provide.

[103] Refer also to clause 7.5 of the WEM Rules.

AEMO runs the Dispatch Algorithm every Dispatch Interval, to identify Dispatch Quantities for use in Dispatch Instructions and Market Clearing Prices for use in settlement processes. The Market Schedules (see Section 8.9) also use the Dispatch Algorithm, but with slightly different inputs.

This section provides an overview of the formulation describing the basic form of the Constraint Equations and parameters involved. It necessarily simplifies some aspects of the Dispatch Algorithm. For more detail, see the WEM Procedure: Dispatch Algorithm Formulation published by AEMO under clause 7.2.5.

8.3.1 Mathematical Formulation

Clause 7.2.4 of the WEM Rules sets out the high-level formulation for the Dispatch Algorithm, giving the 'objective function' and the constraints to be considered in the optimisation problem.

The objective function is the goal of optimisation. In the WEM, the goal of the Dispatch Algorithm is to maximise the value of RTM trading. Maximising the value of RTM trading is equivalent to minimising the total cost of supplying energy (including consideration of scheduled Loads that may increase or decrease their Withdrawal at certain prices) and FCESS in each Dispatch Interval, while respecting the various constraints on system operation. The objective function can be expressed as a mathematical formula, as shown in Equation 6, which adds up the total cost based on the bids and offers in RTM submissions. This ensures that a lower-priced Facility will be cleared ahead of a higher-priced one.

Equation 6 Simplified objective function

$$maximise\ TotalValue\ where$$

$$\begin{aligned}
TotalValue = & \sum_{f \in Facilities} energyBidPrice_f \times energyDispatch_f - \sum_{f \in Facilities} energyOfferPrice_f \times energyDispatch_f \\
& - \sum_{f \in Facilities} contingencyReserveRaiseOfferPrice_f \times contingencyReserveRaiseDispatch_f \\
& - \sum_{f \in Facilities} contingencyReserveLowerOfferPrice_f \times contingencyReserveLowerDispatch_f \\
& - \sum_{f \in Facilities} regulationRaiseOfferPrice_f \times regulationRaiseDispatch_f \\
& - \sum_{f \in Facilities} regulationLowerOfferPrice_f \times regulationLowerDispatch_f \\
& - \sum_{f \in Facilities} RoCoFControlOfferPrice_f \times RoCoFControlDispatch_f
\end{aligned}$$

While attempting to maximise the value of the objective function, the Dispatch Algorithm must also respect physical limitations on power system operations. These limitations are represented as Constraint Equations[104], and ensure that the Dispatch Algorithm:

- Respects network Equipment Limits. Examples of the form of Constraint Equations for Network Constraints are given in Section 6.6.2.

[104] Constraint Equations usually use the 'greater than or equal to' operator rather than the 'equal to' operator, as this simplifies the optimisation process.

- Dispatches NCESS according to pre-set Constraint Equations, either in the same form as Network Constraints, or as custom format Constraint Equations.
- Meets the total energy demand, through an 'energy balance constraint', in the form:

$$\sum_{f \in Facilities} energyDispatch_f = demandForecast$$

- Respects ramp rates in RTM Submissions, whether ramping up or down, using the form:

$$energyDispatch_{Facility1} \leq actualSCADA_{Facility1} + rampCapability_{Facility1}$$

$$energyDispatch_{Facility1} \geq actualSCADA_{Facility1} - rampCapability_{Facility1}$$

These constraints mean that a Facility will only be dispatched to a set point it can reach.

- Meets Regulation and Contingency Reserve Lower requirements (which are set outside the Dispatch Algorithm and provided as inputs), using the form:

$$\sum_{f \in Facilities} regulationRaiseDispatch_f \geq regulationRaiseRequirement$$

$$\sum_{f \in Facilities} regulationLowerDispatch_f \geq regulationLowerRequirement$$

$$\sum_{f \in Facilities} contingencyReserveLowerDispatch_f \geq contingencyReserveLowerRequirement$$

That is, the sum of Regulation Raise dispatch across all Facilities must deliver at least the needed quantity of Regulation Raise, and likewise for Regulation Lower and Contingency Reserve Lower.

- Procures sufficient Contingency Reserve Raise to cover the loss of any Facility that has been dispatched for energy, using the form:

$$\sum_{f \in Facilities} contingencyReserveRaiseDispatch_f - energyDispatch_{Facility1} \geq 0$$

$$\sum_{f \in Facilities} contingencyReserveRaiseDispatch_f - energyDispatch_{Facility2} \geq 0$$

$$\dots$$

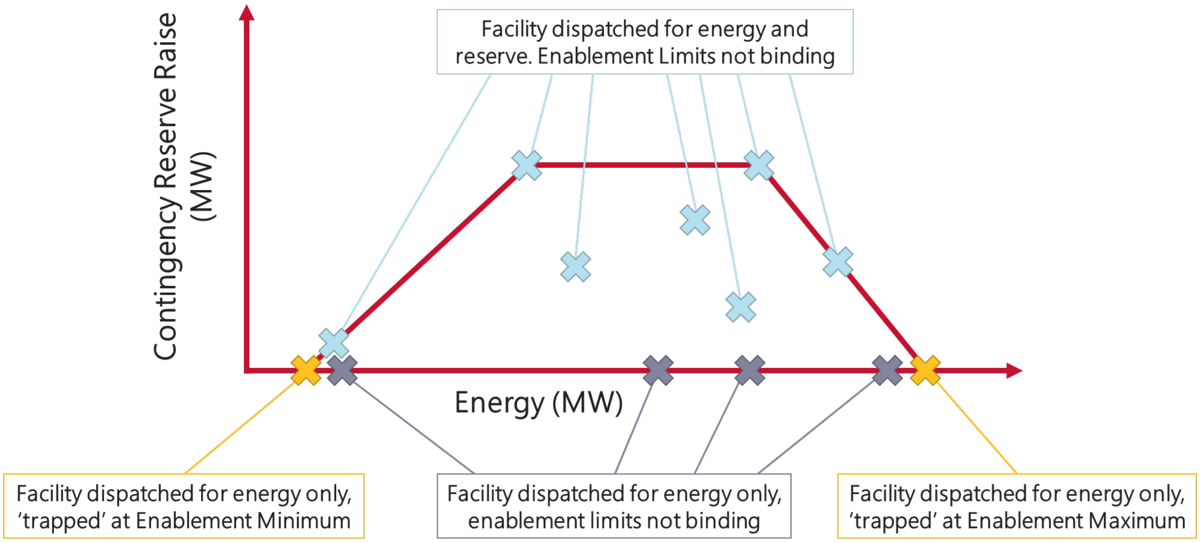
$$\sum_{f \in Facilities} contingencyReserveRaiseDispatch_f - energyDispatch_{FacilityN} \geq 0$$

The Dispatch Algorithm can also include Contingency Reserve Raise Constraint Equations to cover Network Contingencies which would result in the loss of multiple Facilities. These equations take a similar form, but also include a term for the Load that would be lost with a network element.

Most of these constraints will not bind, because only the highest output Facility (or group of Facilities forming the Network Contingency with the largest risk) will set the Contingency Reserve Raise requirement.

- Ensures that Facilities offering to provide FCESS are dispatched for energy at a feasible operating point, that is, to implement the FCESS trapezia discussed in Section 5.6.1.
- If a Facility offers to provide FCESS but is not currently producing energy at a point between the Minimum and Maximum Enablement Limits, its FCESS offers will be disregarded in the Dispatch Schedule (though they will be included in other Market Schedules). Such a Facility is said to be ‘stranded’ outside the FCESS trapezium.
- If a Facility offers to provide FCESS, and it is currently producing energy at a point between the Minimum and Maximum Enablement Limits, its energy dispatch will be restricted to being between those limits. If the Facility is not dispatched for ESS and is dispatched for energy at one of the Enablement Limits, it is said to be ‘trapped’ inside the FCESS trapezium, as shown in Figure 14. Without the Enablement Limit Constraints, such a Facility may have been dispatched for zero energy, or for more than its Enablement Maximum[105].

Figure 14 Possible dispatch outcomes for a Facility with active Enablement Limit Constraints



As noted above, this is a simplification of the formulation, and the actual equations used in the Dispatch Algorithm include additional complexity. For example, most constraints include ‘slack variables’ with ‘constraint violation penalties’ that allow the Dispatch Algorithm to still produce an output when one or more constraints cannot be fully satisfied. Where no feasible solution that respects all constraints exists, the Dispatch Algorithm will produce a solution that violates one or more Constraint Equations. When this happens, AEMO carries out an automatic Constraint Relaxation process where the right-hand sides of the violated Constraint Equations are adjusted in small increments until no violation occurs.

[105] AEMO will inform avoid the FCESS-based restrictions in future Dispatch Intervals by:

- Adjusting the RTM Submission for the Facility to remove FCESS offers.
- Adjusting the RTM Submission participants when their Facilities are trapped in each published Market Schedule. The operator of a trapped Facility which does not wish to remain committed can for the Facility to include an Enablement Minimum higher than the current energy Injection.
- Adjusting Facility energy output to reduce Injection below the stated Enablement Minimum (while remaining within the Dispatch Tolerance).

8.3.2 Non-linear parameters

ESS constraints also include some non-linear parameters that are determined by a dynamic assessment of system conditions:

- Contingency offsets to adjust the quantity of Contingency Reserve procured (a higher RoCoF Control Requirement means less Contingency Reserve required).
- Facility Performance Factors (based on the Facility Speed Factors discussed in Section 5.6.2) to reflect the contribution towards providing Contingency Reserve of different speed Facilities, which is also affected by the RoCoF Control Requirement.
- The RoCoF Control Requirement, which is traded off against the Contingency Reserve Raise Quantity through its ability to increase the capability of slower responding Facilities to arrest frequency during a contingency (by affecting Facility Performance Factors), and to reduce the overall Contingency Reserve Raise requirement (by affecting Contingency offsets).

The RoCoF Control Requirement is determined in two parts:

- The Minimum RoCoF Control Requirement is the quantity required to ensure that the Rate of Change in the SWIS Frequency is restricted to the RoCoF Safe Limit (currently 0.25 Hz over any 500 ms period).
- An Additional RoCoF Control Requirement may be determined if procuring additional RCS would allow a reduction in the quantity of Contingency Reserve Raise, at a lower overall cost.

8.4 Price determination[106]

Market suspension and pricing rules discussed are currently under review by EPWA. These rules may affect price determination. The draft rules for market suspension and pricing is covered in Section 8.8, However, this may be revised in a future release as more information becomes available.

For each Dispatch Interval, AEMO determines a Market Clearing Price for energy and each FCESS. The Market Clearing Price is the marginal cost of providing an increment of the service at the Reference Node (the Perth Southern Terminal 330 kV busbar). Marginal pricing ensures that participants are paid for the value of the service they provide rather than the cost, while providing an incentive to offer their actual costs of providing the service; assuming there is sufficient competition, a participant offering below cost risks losing money if dispatched as the marginal Facility, while a participant offering above cost risks not being dispatched (and losing profitable revenue).

Because pricing is determined as at the Reference Node, a binding Network Constraint can mean that a Facility not at the Reference Node is dispatched but the Market Clearing Price for energy is lower than its cleared offer price. Such a Facility will be eligible for Energy Uplift Payments, as discussed in Section 10.4.1.

In some situations, alternative pricing mechanisms apply:

- Where the Dispatch Algorithm fails to run, Market Clearing Prices are set based on the forecast prices for that Dispatch Interval.

[106] See also clauses 7.11A – 7.11B of the WEM Rules.

- Where the Dispatch Algorithm uses incorrect input data, and AEMO identifies the situation within 30 minutes, the Dispatch Interval is an 'Affected Dispatch Interval'. Market Clearing Prices are set to the prices for the most recent unaffected Dispatch Interval.
- Where AEMO intervenes in market processes, prices are set using a 'what if' run of the Dispatch Algorithm (see Section 8.7).

Although the Dispatch Interval is five minutes, five-minute energy metering data is not currently available from all Facilities, so energy settlement is performed based on 30-minute Trading Intervals[107]. The energy price used in settlement is the Reference Trading Price for a Trading Interval. The Reference Trading Price is the average of the Market Clearing Prices for the six Dispatch Intervals in the Trading Interval (see Section 10.4).

8.5 Co-optimisation examples

The following examples explore how co-optimisation and marginal pricing work to allow Market Participants to be commercially indifferent to whether their plant is dispatched for energy or for ESS. For simplicity, the examples:

- Do not include ramping, network, minimum enablement, or other constraints.
- Consider a single ESS: Contingency Reserve Raise.
- Take the ESS requirement as an input, rather than using risk constraints to set the requirement as part of the Dispatch Algorithm.
- Use MW rather than MWh, which effectively assumes instantaneous ramping.

Examples 1 and 2 are likely to represent market dynamics most of the time. Appendix A2 provides further examples which explore the interaction of binding minimum enablement constraints on pricing dynamics and implications for FCESS Uplift Payments.

8.5.1 Example 1: Reserve price set by opportunity cost of backing off cheap energy provider

In this example, Facility 1 is the only Facility that can provide reserve. Even though it has the cheapest energy offer, it must be backed off to provide reserve. The remaining energy is provided by the more expensive Facility 2.

Both Facilities can offer to supply reserve at their variable cost ($0/MW) without having to account for potentially missing out on profits from energy supply — the Market Clearing Prices determined by the Dispatch Algorithm account for the opportunity cost of backing off energy output to provide reserve.

Inputs

System parameters	
Energy demand	100 MW

Facility 1 parameters		
Maximum capacity		50 MW
	Price ($/MW)	Quantity (MW)
Energy offer	100	50

Facility 2 Parameters		
Maximum capacity		100 MW
	Price ($/MW)	Quantity (MW)
Energy offer	500	100

[107] Five-minute settlement (5MS) will be implemented on 1 October 2025 at which point the Dispatch Interval and Trading Interval will both be five-minutes and the energy settlement price will equal the relevant five-minute Energy Market Clearing Price.

Reserve requirement	25 MW

Facility 1 parameters		
Reserve offer	0	50

Facility 2 Parameters		
Reserve offer	0	0

Optimisation problem

The algorithm must:

- Dispatch at least enough energy to meet the demand.
- Dispatch at least enough reserve to meet the reserve requirement.
- Not dispatch a Facility for more than its total capacity.

The total cost is the dispatched energy and reserve multiplied by the relevant offer prices.

Equation 7: objective function for dispatch examples

$minimise\ TotalCost\ where$

$$\begin{aligned} TotalCost = \ & energyDispatch_{Facility1} \times energyOfferPrice_{Facility1} \\ & + energyDispatch_{Facility2} \times energyOfferPrice_{Facility2} \\ & + reserveDispatch_{Facility1} \times reserveOfferPrice_{Facility1} \\ & + reserveDispatch_{Facility2} \times reserveOfferPrice_{Facility2} \end{aligned}$$

$subject\ to:$

Equation 8: energy balance constraint for dispatch examples

$$\sum_{f \in Facilities} energyDispatch_f \geq demandForecast$$

Equation 9: reserve requirement constraint for dispatch examples

$$\sum_{f \in Facilities} reserveDispatch_f \geq reserveRequirement$$

Equation 10: joint capacity constraints for dispatch examples

$$energyDispatch_{Facility1} + reserveDispatch_{Facility1} \leq maximumCapacity_{Facility1}$$

$$energyDispatch_{Facility2} + reserveDispatch_{Facility2} \leq maximumCapacity_{Facility2}$$

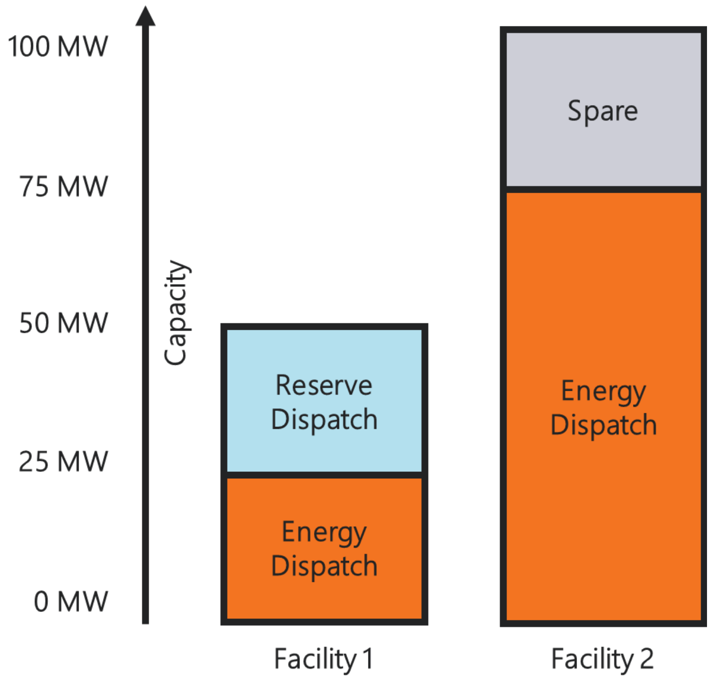
Outputs

Dispatch

The only way to satisfy the reserve requirement (Equation 9) is to dispatch Facility 1 for all the reserve. The cheapest way to meet the energy demand (Equation 8) is to dispatch Facility 1 for as much energy as possible (given its remaining capacity), then dispatching Facility 2 for the remainder.

- Facility 1 Energy dispatch: 25 MW, reserve dispatch: 25 MW.
- Facility 2 Energy dispatch: 75 MW, reserve dispatch: 0 MW.

Figure 15 Co-optimisation Example 1 dispatch



The total cost to serve load while meeting the reserve requirement is:

$$TotalCost = (25 \times \$100) + (75 \times \$500) + (25 \times \$0) + (0 \times \$0) = \$40{,}000$$

Marginal prices

The marginal prices are based on the additional cost of serving another increment of the service. Facility 2 is the marginal Facility for energy. Facility 1 is the marginal Facility for reserve, but pricing for the two markets interacts, so the marginal reserve price is affected by the marginal energy price.

- *Energy*: If demand increased by 1 MW (to 101 MW), Facility 2 would be dispatched for one more MW.

  $$TotalCost = (25 \times \$100) + (\mathbf{76} \times \$500) + (25 \times \$0) + (0 \times \$0) = \$\mathbf{40,500}$$

  The change in total costs would be $500/MW, and this is the marginal price for energy.

- *Reserve*: If the requirement were increased by 1 MW (to 26 MW), Facility 1 would have to be backed off by 1 MW energy to make room. That unit of energy would instead be provided by Facility 2 (at a cost of $500 instead of $100).

  $$TotalCost = (\mathbf{24} \times \$100) + (\mathbf{76} \times \$500) + (\mathbf{26} \times \$0) + (0 \times \$0) = \$\mathbf{40,400}$$

  The change in total costs would be $400, so this is the marginal price for reserve.

Payments

Facility 1 revenue is $(25MW \times \$500) + (25MW \times \$400) = \$22{,}500$

Facility 1 costs are $(25MW \times \$100) + (25MW \times \$0) = \$2{,}500$

Facility 1 profit is $\$22{,}500 - \$2{,}500 = \$20{,}000$

Facility 2 revenue is $75MW \times \$500 = \$37{,}500$

Facility 2 costs are $75MW \times \$500 = \$37{,}500$

Facility 2 profit is $\$37{,}500 - \$37{,}500 = 0$

Even though Facility 1 offers a price of $0 to provide reserve (because that is its cost of providing the service), the Facility is indifferent to whether it provided energy (at $500/MW, but with $100 fuel cost) or reserve (at $400/MW, with $0 fuel cost).

Facility 2 is the marginal Facility. Assuming its offer price reflects its cost to supply, it is indifferent to providing energy or not, as it receives payment equal to its costs.

8.5.2 Example 2: Reserve price is zero due to spare capacity at reserve capable Facility

Inputs

System parameters	
Energy demand	100 MW
Reserve requirement	25 MW

Facility 1 parameters		
Maximum capacity		50 MW
	Price ($/MW)	**Quantity (MW)**
Energy offer	100	50
Reserve offer	0	50

Facility 2 Parameters		
Maximum capacity		100 MW
	Price ($/MW)	**Quantity (MW)**
Energy offer	500	100
Reserve offer	0	**100**

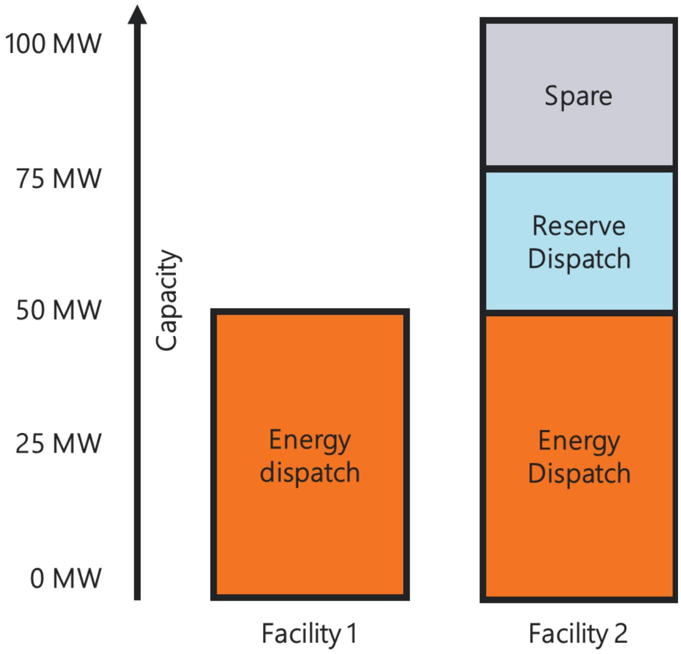
Outputs

Dispatch

The cheapest way to meet the energy demand (Equation 8) is to dispatch Facility 1 for as much energy as possible (to its maximum capacity), then dispatching Facility 2 for the remaining energy, and all the reserve.

- Facility 1 Energy dispatch: 50 MW, reserve dispatch: 0 MW.
- Facility 2 Energy dispatch: 50 MW, reserve dispatch: 25 MW.

Figure 16 Co-optimisation Example 2 dispatch



The total cost to serve load while meeting the reserve requirement is:

$$TotalCost = (50 \times \$100) + (50 \times \$500) + (0 \times \$0) + (25 \times \$0) = \$30{,}000$$

Marginal prices

The marginal prices are based on the additional cost of serving another increment of the service. Facility 2 is still the marginal Facility for energy and is now also the marginal Facility for reserve.

- *Energy*: If demand increased by 1 MW (to 101 MW), Facility 2 would be dispatched for one more MW.

  $$TotalCost = (50 \times \$100) + (\mathbf{51} \times \$500) + (0 \times \$0) + (25 \times \$0) = \$\mathbf{30,500}$$

  The change in total costs would be \$500, and this is the marginal price for energy.

- *Reserve*: If the requirement were increased by 1 MW (to 26 MW), Facility 2 will provide it with no other change to the dispatch.

  $$TotalCost = (50 \times \$100) + (50 \times \$500) + (0 \times \$0) + (\mathbf{26} \times \$0) = \$30{,}000$$

  The change in total costs would be \$0, so this is the marginal price for reserve.

Payments

Facility 1 revenue is $(50MW \times \$500) + (0MW \times \$0) = \$25{,}000$

Facility 1 costs are $(50MW \times \$100) + (0MW \times \$0) = \$5{,}000$

Facility 1 profit is $\$25{,}000 - \$5{,}000 = \$20{,}000$

Facility 2 revenue is $(50MW \times \$500) + (25MW \times \$0) = \$25{,}000$

Facility 2 costs are $(50MW \times \$500) + (25MW \times \$0) = \$25{,}000$

Facility 2 profit is $\$25{,}000 - \$25{,}000 = \$0$

Facility 1 receives the same profit as it did in Example 1 (the difference in revenue between the examples reflects the cost to generate the additional 25 MW of energy). Again, Facility 2 is the marginal Facility for both energy and reserve, so payment received is equal to the cost, and the owner is indifferent to providing either service.

8.6 Dispatch Instructions and dispatch compliance[108]

AEMO uses the energy and FCESS Dispatch Quantities calculated by the Dispatch Algorithm to issue Dispatch Instructions for each Dispatch Interval to Scheduled Facilities, Semi-Scheduled Facilities, DSPs, and Interruptible Loads. Dispatch Instructions are not issued to Non-Scheduled Facilities, but AEMO still records all the relevant information.

Almost all Dispatch Instructions are issued shortly before the start of the relevant Dispatch Interval. The exception is Dispatch Instructions to DSPs, which are issued two hours ahead of the relevant Dispatch Interval and are based on the forecast in the Pre-Dispatch Schedule.

Each Dispatch Instruction specifies:

- A Dispatch Interval.
- A Dispatch Target (for Scheduled Facilities or Semi-Scheduled Facilities providing ESS) or a Dispatch Cap (for Semi-Scheduled Facilities not providing ESS).
- A Dispatch Forecast (for Semi-Scheduled Facilities and Non-Scheduled Facilities), which represents the expected unconstrained output of the Facility based on its RTM Submissions.
- An ESS enablement quantity for each FCESS that the Facility is to provide.

All Facilities must comply with the most recently received Dispatch Instruction:

- Where issued a Dispatch Target, a Scheduled Facility or Semi-Scheduled Facility must ramp at a constant rate from the start of the Dispatch Interval to meet the Dispatch Target (within a tolerance) at the end of the Dispatch Interval[109].
- Where issued a Dispatch Cap, a Semi-Scheduled Facility must not inject more than the Dispatch Cap (within a tolerance) during the interval – with allowance for ramping (also at a constant rate), if the start of interval position is higher than the cap.
- Where Semi-Scheduled Facility output can be controlled in some way (such as by self-curtailment or by operating an Energy Storage Resource), the Market Participant is not allowed to use that control in a way that increases deviation from the Dispatch Forecast. Semi-Scheduled Facilities are otherwise free to inject according to their available fuel.
- Dispatch Targets issued to DSPs represent a required reduction from Relevant Demand (which is the expected consumption level on which Capacity Credits are based). If the DSP does not meet this reduction, it will be non-compliant with dispatch, and will also face Reserve Capacity Refunds.

[108] The Dispatch process is covered in more detail in clause 7.6 of the WEM Rules, while Market Participant obligations with respect to Dispatch Instructions are covered in clause 7.10 of the WEM Rules.

[109] AEMO can exempt Facilities from this requirement when supported by evidence that the Facility is not capable of linear ramping.

Where a Facility cannot meet a Dispatch Instruction, the Participant must notify AEMO, update its RTM Submissions to reflect the revised capability of the Facility, and submit any relevant Forced Outages. Participants holding Capacity Credits may also be required to refund Reserve Capacity payments.

AEMO monitors Facility compliance with Dispatch Instructions, according to the approach set out in the relevant market procedure on dispatch[110].

8.7 Scarcity and intervention[111]

When supply of energy or ESS is scarce, or where PSS is under threat, AEMO may need to intervene in market processes by directing Market Participants or Facilities to operate in a particular way. This may include producing energy at a level higher or lower than they would have absent the intervention, connecting to the SWIS to provide energy or FCESS that it otherwise would not have. It can also include instructions to Network Operators to drop load or curtail distributed solar PV. This can be achieved either by AEMO including manual Constraint Equations in the Dispatch Algorithm, by the participant updating its RTM Submissions to reflect the direction, or by a combination. This departure from standard market processes is an 'AEMO Intervention Event' and triggers a different approach to Market Clearing Price determination.

During scarcity, AEMO may also call upon providers with whom AEMO has entered into a Supplementary Capacity Contract with. The terms of dispatch will be governed by the relevant contract.

In an 'Intervention Dispatch Interval', Facility dispatch is still based on Dispatch Algorithm outputs, but pricing is based on an alternative Scenario where Dispatch Algorithm inputs are adjusted to remove the intervention — manual constraints will be removed, and affected offers will revert to what they were before the direction.

This approach ensures that Market Clearing Prices are not depressed by AEMO's intervention. For example, if AEMO directs an expensive Facility to synchronise and provide energy, that energy will displace a cheaper Facility, and the marginal cost of the next unit of energy will be lower than it would have been (because the cheaper Facility is now available to provide the marginal unit of energy). Without intervention pricing, this lower Market Clearing Price would have been used in settlement, but it is instead replaced by the Market Clearing Price from the alternative Scenario.

8.8 Market Suspension and Administered Pricing

Market suspension and pricing rules discussed are currently under review by EPWA. The content in this section reflects the draft rules for market suspension and pricing and may be revised in a future release as more information becomes available.

In extreme circumstances, AEMO may suspend the RTM. When the RTM is suspended, AEMO must apply administered prices for Energy and FCESS in all Dispatch Intervals in the suspension period. The administered prices depend on the reason that AEMO suspended the RTM as described below.

[110] See AEMO | WEM Procedures

[111] See also clause 7.7 of the WEM Rules.

Table 4 Administered pricing by reason for market suspension

Reason for market suspension	Administered Prices
System shutdown of major supply disruption	Final Market Clearing Prices for Energy and all FCESS are zero.
Suspension requested by Minister of Energy exercising emergency powers	Final Market Clearing Prices for Energy and all FCESS set based on Minister of Energy's instructions
AEMO determines it has become impossible to maintain PSR in accordance with the WEM Rules	Final Market Clearing Price for Energy and all FCESS for a given Dispatch Interval equals the average of Final Market Clearing Prices (for Energy or FCESS as relevant) in equivalent Dispatch Intervals over the most recently completed four Trading Weeks,

See clauses 7.11D and 7.11E of the WEM Rules for more details on market suspension and pricing.

8.9 Market Schedules

Although Dispatch Instructions are based on inputs for the next five-minute interval, AEMO also uses the Dispatch Algorithm to project future conditions. AEMO publishes three Market Schedules that forecast future dispatch and pricing outcomes. These schedules signal forecast market outcomes at regular intervals ahead of real time, allowing participants to see what is projected to happen, adjust their RTM Submissions, and react to changes made by other participants.

Market Schedules are Public Information[112], and include data on expected:

- Demand.
- FCESS requirements.
- Energy and ESS shortfalls.
- Dispatch Targets, Dispatch Caps, Dispatch Forecasts, and ESS Enablement Quantities by Facility.
- Binding and near-binding Constraint Equations.
- Market Clearing Prices.
- Facility testing (Reserve Capacity Tests and Commissioning Tests).

The Market Schedules are shown in Table 5.

Table 5 Market Schedules[113]

Schedule	Horizon	Resolution	Frequency	Notes
Dispatch Schedule	2 hours	5 minutes	Every 5 minutes	Very short-term schedule at Dispatch Interval resolution. First interval of horizon gives the actual dispatch. Only includes 'In-Service' Facility capacity.
Pre-Dispatch Schedule	48 hours	30 minutes	Every 30 minutes	Supports commitment, fuel procurement, and STEM activity. Includes 'In-Service' Facility capacity and 'Available' Facility capacity that still has time to synchronise according to Standing Data start-up times.

[112] The only non-public information in Market Schedules is 'trapped' and 'stranded' status of each Facility and Estimated Enablement Losses. These are confidential to the applicable Market Participant.

[113] See also clauses 7.8 and 7.8A of the WEM Rules.

Schedule	Horizon	Resolution	Frequency	Notes
DSP Pre-Dispatch Schedule	48 hours	5 minutes	Every 30 minutes	Provides transparency around potential dispatch of DSPs[114].
Week-Ahead Schedule	7 days	30 minutes	Daily	Provides indicative information to end of feasible short-term Load Forecast horizon.
DSP Week-Ahead Schedule	7 days	5 minutes	Daily	

Each schedule includes Scenarios covering a range of potential market inputs, such as high and low Load Forecasts, and possible network Outages. These Scenarios allow Market Participants to gauge the level of uncertainty in forecasts, and the sensitivity of market outcomes to underlying fundamentals. Each Market Schedule includes a 'Reference Scenario' which represents AEMO's best estimate of future dispatch and pricing outcomes.

8.10 Market Advisories[115]

AEMO must inform Rule Participants and the public of current or impending situations that could affect PSS or PSR, or the operation of market processes. Most of the time, this information is published in Outage Plans, ST-PASA or MT-PASA, or Market Schedules. When AEMO observes or forecasts an event that is not covered in other Market Information, it issues a Market Advisory.

AEMO issues a Market Advisory when any of the following has occurred or is expected to occur:

- The SWIS is in an Emergency Operating State (see Section 6.2).
- AEMO cannot operate the SWIS in accordance with the PSS Principles or cannot maintain the SWIS in a Reliable Operating State.
- An AEMO Intervention Event (see Section 8.7).
- A significant Contingency Event.
- Significant involuntary load shedding.
- Problems with AEMO's market systems, control systems, or communication systems.
- System Restart Service is activated.
- Fuel supply is significantly more restricted than usual.
- Any part of the WEM Rules is suspended (under clause 2.44.1).

A Market Advisory will specify the time period to which the advisory relates and information on how Market Participants should respond to the situation. The WEM Rules recognise that sometimes AEMO will have to react quickly to a situation and may not be able to issue a Market Advisory until after the event.

[114] AEMO calculates two key quantities for each DSP for each Pre-Dispatch Schedule and Week-Ahead Schedule:

- DSP Forecast Capacity: the forecast total available reduction in MW of a DSP taking into account its Relevant Demand, RCOQ and Minimum Consumption (as estimated by AEMO)
- DSP Forecast Reduction: the expected reduction in MW of a DSP based on its submitted DSP Unconstrained Withdrawal Quantities and DSP Constrained Withdrawal Quantities.

[115] See also clause 7.11 of the WEM Rules.

Market Participants are obliged to keep AEMO informed of any circumstances that they become aware of that might result in AEMO issuing a Market Advisory.

8.11 RTM Timetable

Figure 17 shows schedule horizons as at 08:00 on the current Trading Day. Figure 18 shows key activities in the dispatch process for the 08:00 to 08:05 Dispatch Interval. All information is available to the public.

AEMO can extend publication deadlines by up to two days if there is a problem with data processing.

Figure 17 Market Schedule horizons

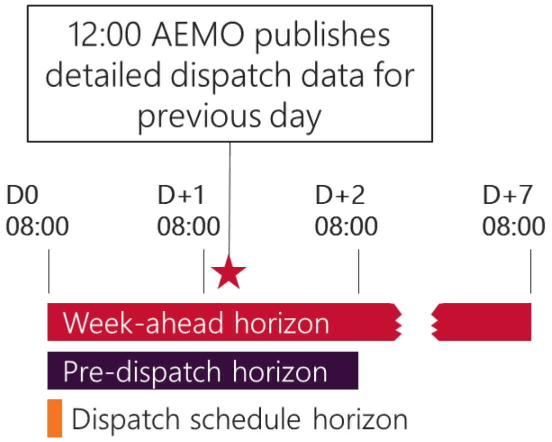
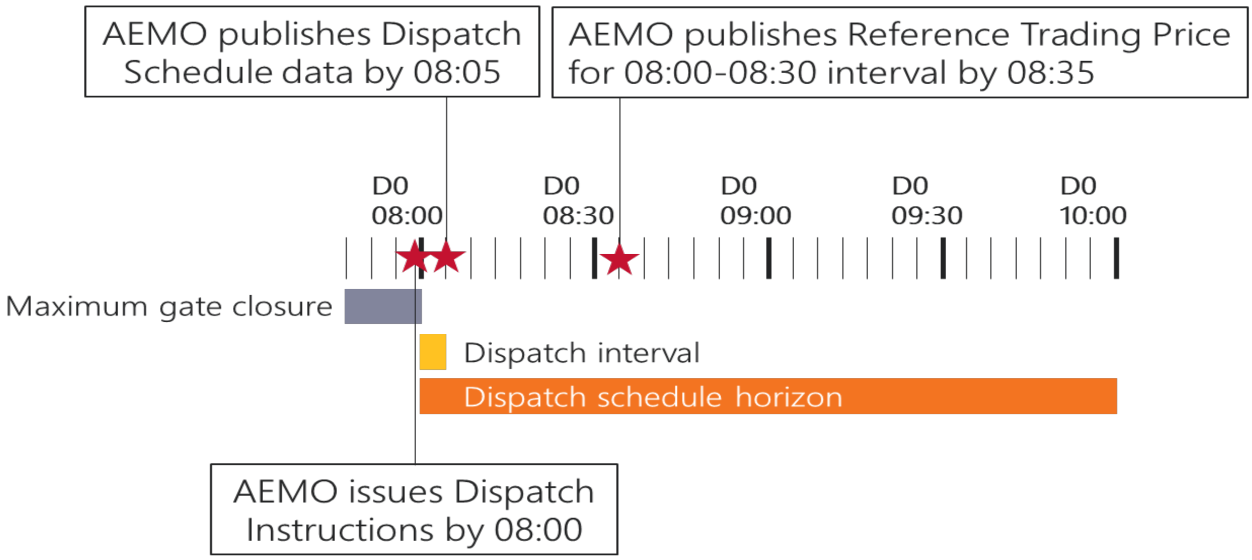


Figure 18 Dispatch activities



9 The Short-Term Energy Market

9.1 Overview

The STEM is a financially binding, energy-only, day-ahead market which provides a centrally coordinated opportunity for Market Participants to trade around their Bilateral Contract positions, supplementing and complementing the off-market Bilateral Contracts regime. This allows those trading under Bilateral Contracts to change their position, while allowing those not trading under Bilateral Contracts to take a position. It also provides a firm financial basis for commitment of long-start-time Facilities on the following Trading Day.

AEMO operates the STEM daily on the Scheduling Day for each Trading Interval of the following day (the Trading Day). AEMO determines, for each Trading Interval of the Trading Day, a single clearing price not including any potential network congestion, as well as the quantities that participants are cleared to sell to or purchase from AEMO. The STEM schedules are contracts between Market Participants and AEMO. The STEM Auction is designed so that AEMO purchases the same amount of energy it sells and has no net exposure.

Participation in the STEM is open to all Market Participants but is not compulsory. There is no obligation for a Market Participant to meet its NBP in the STEM, though Market Participants holding Capacity Credits must make adequate energy available in the STEM to cover their RCOQs or face capacity refunds.

9.2 Bilateral Contracts

Bilateral Contracts are agreements formed between any two parties for the sale of electricity by one party to the other. Bilateral Contracts are formed on a purely commercial basis, and the WEM has no role or interest in how they are formed, or in the conditions they impose on the parties. AEMO does not operate any secondary trading market for Bilateral Contracts.

Bilateral Contracts provide holders with certainty over their settlement position with respect to that transaction. To the extent that one party does not produce or consume the quantity of energy stated in the contract, (whether due to Facility Outage, Network Constraints, low demand, or deliberate choice), then the deviation will be settled through WEM settlement processes. This places discipline on Market Participants to only form Bilateral Contracts that reflect a reasonable expectation of the ability of the Network to facilitate the delivery of that energy.

9.3 STEM and Bilateral Submissions[116]

9.3.1 Bilateral Submissions

Bilateral Submissions are usually made by the supplying party. Market Participants can submit Bilateral Submission data for a Trading Day to AEMO at any time between 8:00 am seven days before the Scheduling Day to the Bilateral Submission Cutoff – 8:50 am on the Scheduling Day.

[116] The process for submitting Bilateral Submission and STEM Submissions is set out in clauses 6.2 to 6.3C of the WEM Rules. Require formats for submissions are described in clauses 6.6 and 6.7 of the WEM Rules.

Bilateral Submissions must be balanced, in the sense that the total Loss Adjusted energy to be supplied must match the total Loss Adjusted energy to be consumed. Loss Adjustments are based on static Loss Factors[117], fixed for a year and reflecting average marginal losses between the SWIS Reference Node and the relevant network connection point. These are set annually by Network Operators and published by AEMO.

Market Participants can also submit a Standing Bilateral Submission to AEMO at any time. A Standing Bilateral Submission comprises a Bilateral Submission for any of the seven days of a Trading Week. If a Market Participant does not make a Bilateral Submission to AEMO for a specific Trading Day, AEMO will use the relevant Standing Bilateral Submission as the default submission.

9.3.2 STEM Submissions

Market Participants can make STEM Submissions at any time between 8:30 am seven days before the Scheduling Day to the STEM Submission Cutoff – 10:50 am on the Scheduling Day.

To help Market Participants form their STEM Submissions, AEMO calculates and makes information available to each Market Participant for each Trading Interval in the eight-day period commencing on the relevant Trading Day:

- The RCOQ of each Scheduled and Semi-Scheduled Facility, including the RCOQ of each Separately Certified Component.
- The sum of Capacity-Adjusted Planned Outage Quantities, which relates to the quantity of energy the participant must make available to avoid capacity refunds.
- The total quantity specified in STEM Submissions and Standing STEM Submissions already sent to and accepted by AEMO.
- The Maximum Consumption Capability, which represents the limit on what the participant can bid to purchase in the STEM.
- The Forecast Operational Demand and Forecast Operational Withdrawal as published in the most recent Pre-Dispatch Schedule or Week-Ahead Schedule.

AEMO must also provide Market Participants with the Electric Storage Resource Obligation Intervals that will apply for the relevant Trading Day, and the Electric Storage Resource Obligation Intervals it expects will apply for the seven-day period commencing on the relevant Trading Day.

AEMO updates this information whenever there is a change in the underlying data.

Market Participants offer their entire supply and consumption capacity in the STEM Submission in the form of a generation Portfolio Supply Curve and a Portfolio Demand Curve. From these curves, AEMO generates offers to buy energy and bids to sell energy relative to the NBP of the Market Participant.

Market Participants can also make Standing STEM Submissions. As with standing Bilateral Submissions, these will be used in the STEM Auction for any periods where the Participant does not subsequently make a STEM Submission.

A STEM Submission for a Trading Day comprises:

[117] Determined by Western Power.

- A **Fuel Declaration** – this declares what fuel each dual-fuelled Facility was assumed to be using when forming the Portfolio Supply Curve.
- A **Portfolio Supply Curve for each Trading Interval** – a Portfolio Supply Curve is made up of Price-Quantity Pairs where the cumulative quantity offered represents all the energy being offered to the market from the Market Participant's energy producing resources. Offer Prices must be less than or equal to the Energy Offer Price Ceiling and greater than or equal to the Energy Offer Price Floor. The cumulative quantity of supply offered must increase with increasing price and must not exceed the quantity that the Market Participant has offered into the RTM.
- A **Portfolio Demand Curve for each Trading Interval** – a Portfolio Demand Curve is a demand curve made up of Price-Quantity Pairs where the cumulative quantity bid represents all the energy that the Market Participant might potentially purchase from the market. All bid prices must be greater than or equal to the Energy Offer Price Floor, less than or equal to the Energy Offer Price Ceiling and the cumulative quantity of energy consumption must increase with decreasing price and must not exceed the participant's Maximum Consumption Capability.

9.4 The STEM Auction[118]

AEMO runs the STEM Auction using accepted STEM Submissions and publishes results before the STEM Results Deadline —11:30 am on the Scheduling day.

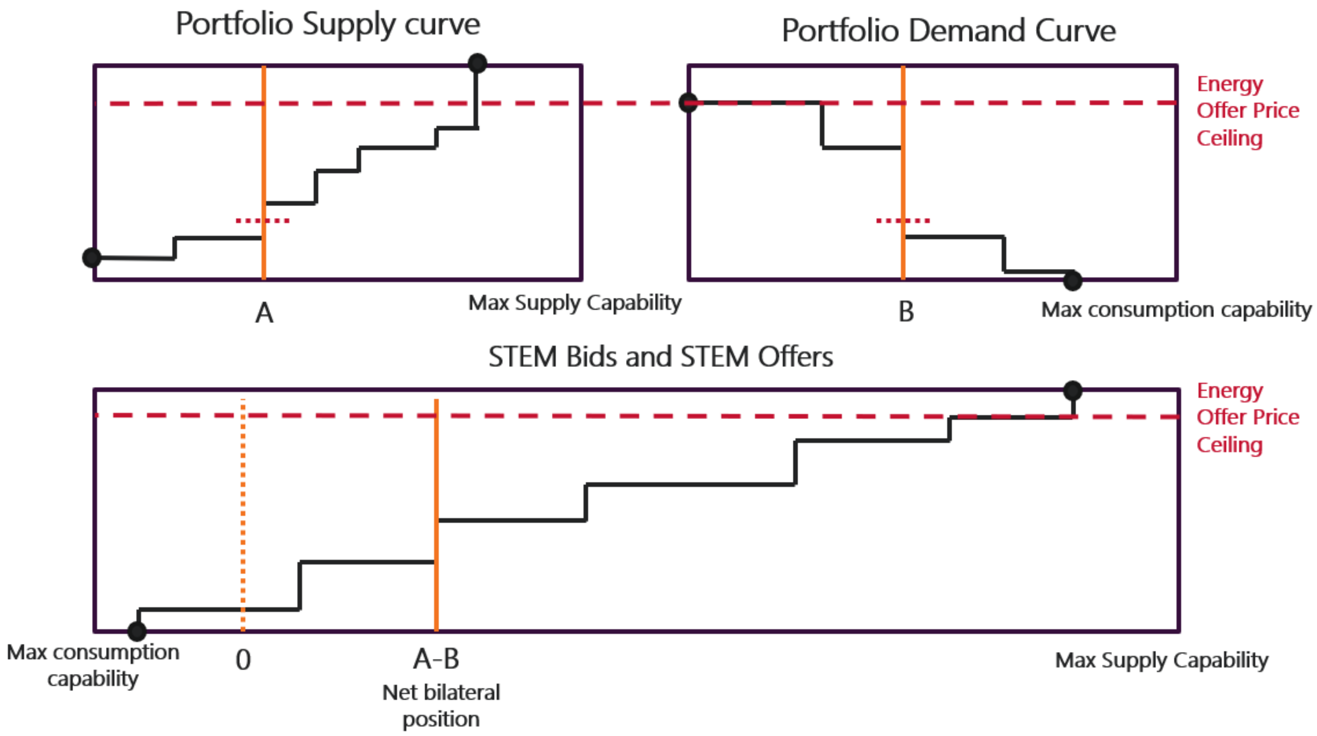
9.4.1 Establishing STEM Offers and Bids

Given a Market Participant's STEM Submission and NBP, AEMO calculates the Market Participant's STEM Offers and STEM Bids.

The top two curves in Figure 19 illustrate a Market Participant's Portfolio Supply Curve and Portfolio Demand Curve for a Trading Interval. The bottom curve illustrates how AEMO forms the STEM Bids and STEM Offers.

[118] See also clauses 6.4 and 6.9 of the WEM Rules. The rules governing suspension of the STEM is covered in clause 6.10 of the WEM Rules.

Figure 19 The Portfolio Supply Curve, Portfolio Demand Curve, and STEM Bids and Offers



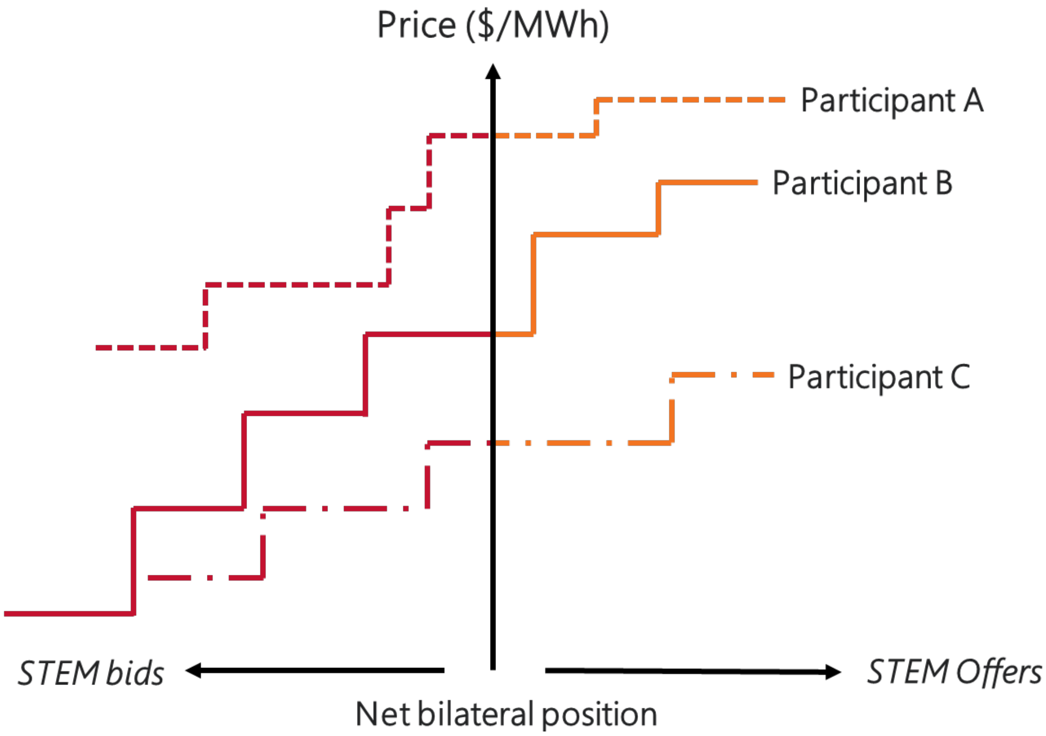
Some points to note about the Portfolio Supply Curve and Portfolio Demand Curve in Figure 19:

- The minimum price that can be included in a submission is the Energy Offer Price Floor.
- The maximum price that can be included in a submission is the Energy Offer Price Ceiling.
- When the Market Participant formed its Portfolio Supply Curve, it expected quantity A to be traded under Bilateral Contracts. Likewise, when it formed its Portfolio Demand Curve it expected quantity B to be traded under Bilateral Contracts. The Market Participant does not tell AEMO the values of A and B, but it does need to be aware of the quantity so it can ensure its Price-Quantity Pairs are consistent with its NBP. The short dotted horizontal lines centred on points A and B indicate the price corresponding to the NBP (A-B) in the bottom curve. If AEMO is to produce STEM Offers and Bids that match the Market Participant's expectation, the Market Participant must ensure that:
- Demand not traded bilaterally is bid at a price lower than that corresponding to the NBP.
- Generation not traded bilaterally is offered at a higher price.

The bottom part of Figure 19 shows an individual Market Participant's STEM Offers and Bids relative to its NBP. AEMO forms the lower curve in Figure 19 by determining the net quantity of energy that the Market Participant is willing to provide at every possible price. Having formed such a curve, AEMO identifies the quantity corresponding to the NBP. Relative to this point, everything with a higher price is a STEM Offer and everything with a lower price is a STEM Bid.

Each Market Participant will have its own set of STEM Offers and Bids. Different Market Participants will have different prices associated with their NBPs. This is illustrated for three Market Participants in Figure 20.

Figure 20 STEM Bids and Offers are defined relative to NBPs



The NBPs of the three participants shown in Figure 20 will all be different. Figure 20 does not indicate whether each Participant is solely a producer, solely a consumer, or both producer and consumer. Thus:

- Any of the participants could be a producer only, with a positive NBP indicating it will have net Injection. Its STEM Bids would reflect a decrease in Injection while its STEM Offers would reflect an increase in Injection.
- Any of the participants could be a consumer only, with a negative NBP indicating it will have net Withdrawal. Its STEM Bids would reflect an increase in consumption while its STEM Offers would reflect a decrease in consumption.
- Any of the participants could be both a producer and a consumer, in which case its NBP could be positive or negative. Its STEM Bids would reflect a combination of a decrease in Injection and an increase in consumption while its STEM Offers would reflect a combination of an increase in Injection and a decrease in consumption.

The three Participants are unlikely to have the exact same expectation as to what the STEM price will be. Participant A expects to incur a relatively high price to meet its NBP, while Participant C expects to incur a relatively low price. Because Participant A expects to incur a high price, it is prepared to pay a high price under its STEM Bid to buy out of its contract position. Participant C expects a lower price; perhaps its STEM Offers are at relatively low prices because it has lots of under-utilised low-cost generation capacity. It is apparent that a result of the STEM Auction should be that some of Participant A's STEM Bids are accepted, with the result that it sources energy from the STEM rather than its own supply, with Participant C's lower cost STEM Offers being used to replace that supply.

9.4.2 Auction

To see how the Auction works, all the STEM Offers must be formed into one aggregate offer stack, and all the STEM Bids into one aggregate bid stack. In Figure 20 above, the STEM Bids are shown as a reduction in net supply relative to the NBP as prices fall, but in Figure 21 below the bid curve is reversed, as it represents an increase in gross demand as prices fall.

Figure 21 The STEM Auction

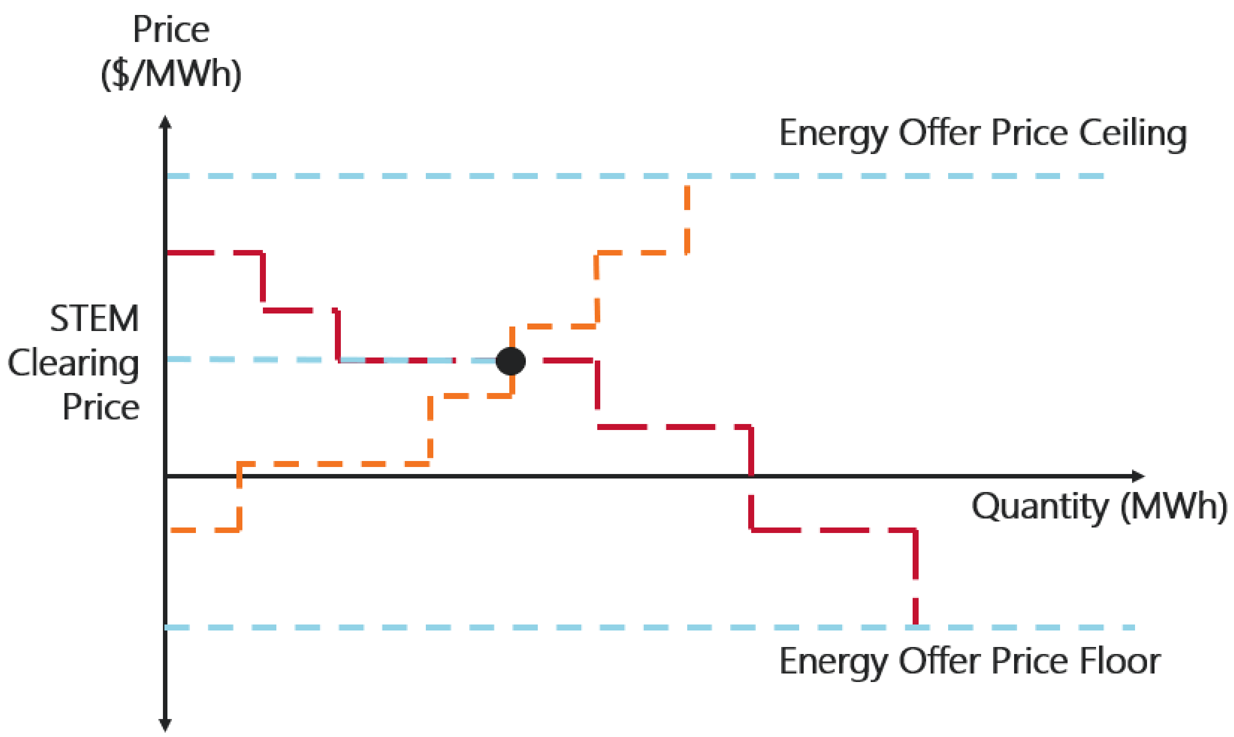


Figure 21 shows the same information as Figure 20, but the information has been re-organised to show the point where the total STEM Bids accepted equals the total STEM Offers accepted. It is apparent that the first step of Participant C's STEM Offer is fully scheduled, being used to offset the energy reduction caused by accepting all of Participant A's STEM Bids and some of Participant B's STEM Bids.

The point where the curves cross defines the market clearing STEM solution, which determines the STEM Clearing Price. All offers to sell with lower offer prices and all bids to buy with higher bid prices are deemed scheduled in the STEM. The STEM is designed to match supply with demand while supplying the maximum possible quantity of energy at the lowest possible price in all situations. Bids and offers with prices equal to the STEM price will be subject to additional tie-breaking rules. The STEM price can be negative.

The example illustrated above shows that the STEM Clearing Price would have a reasonable value even if no Portfolio Demand Curve were submitted to the STEM Auction. This is because, as shown in Figure 19, the supply curves for Facilities for levels below their NBP will be converted to STEM Bids. Even if no energy were scheduled in the STEM, the price would still have to be between the cost of the highest-priced STEM Bid and the lowest-priced STEM Offer, and this difference will normally only be a small amount (e.g. a few cents per MWh). The STEM Auction process will select the lowest price.

Those scheduled in the STEM will be required to settle the amount they are scheduled for with AEMO at the STEM Clearing Price. That is, net suppliers will be paid the STEM price and net consumers will pay the STEM price.

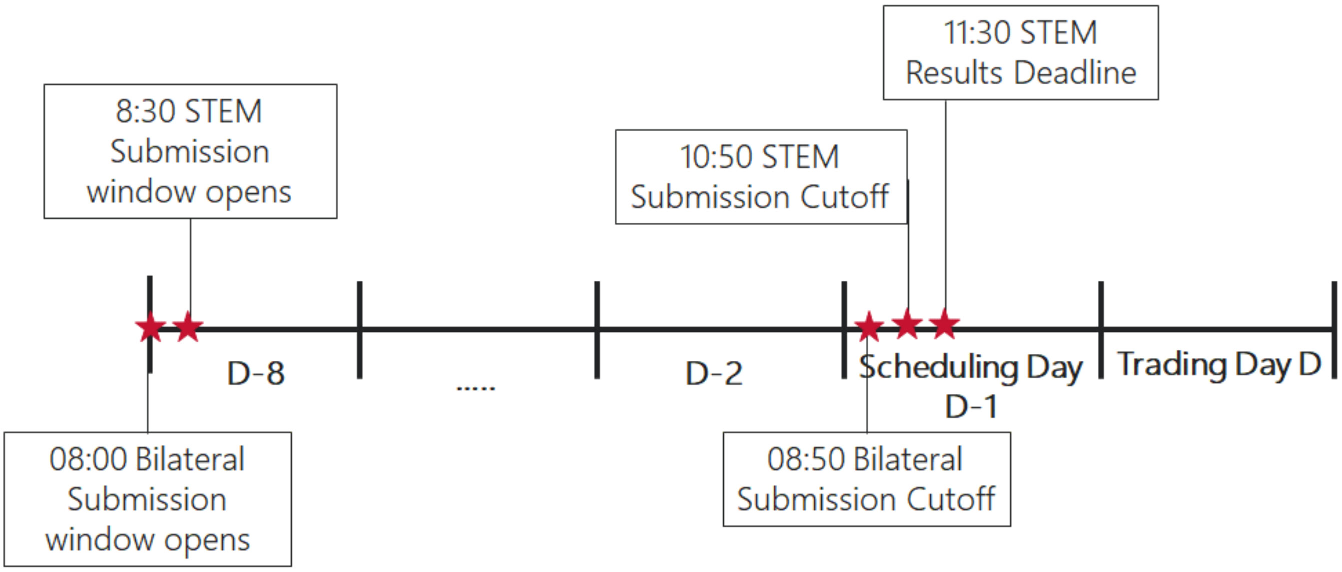
Once the STEM has been cleared, each Market Participant will have a NCP equal to its NBP as modified by its net purchase or sale in the STEM.

9.5 The STEM timetable

Figure 22 shows the relevant deadlines for the STEM on the Scheduling Day.

The Bilateral Submission Cut-off, the STEM Submission Cut-off, and the STEM Results Deadline can be extended by AEMO by up to two hours, as long as the extension would maintain at least 110 minutes for participants to make submissions with full and correct information.

Figure 22 STEM timetable



10 Settlement

The rules discussed in this section pertaining to the allocation of Market Fees and FCESS costs are currently under review by EPWA. This section will be revised in a future release as more information becomes available.

10.1 Overview of the settlement process

Settlement is the process by which transactions in, and costs of participation in, the WEM are financially settled by AEMO. AEMO is the settlement agent responsible for:

- Calculating all settlement amounts.
- Collecting amounts receivable from Rule Participants.
- Disbursing those amounts to Rule Participants for services provided.

Settlement amounts comprise multiple segments covering:

- Transactions in the STEM, the RCM, and RTM (the latter including energy and ESS).
- Market participation fees.
- Outage Compensation.

Settlement amounts are discussed in further detail in Section 10.4.

Settlement of all transactions occurs on a weekly basis, around four weeks after the end of the relevant Trading Week. Settlement adjustments will be made up to 12 months after the relevant Trading Week, allowing for resolutions of disagreements, incorporation of improved meter data or other data, and corrections of errors in settlement.

Settlement timelines are discussed further in Section 10.2.

10.2 Settlement timing[119]

10.2.1 Settlement period and interval

The settlement period in the WEM is a Trading Week which runs from 8:00 am on a Saturday to 8:00 am the following Saturday. A Trading Week comprises seven Trading Days with each Trading Day running from 8:00 am through to 8:00 am the next day. A Trading Day comprises 48 half-hour intervals. Hence, the first Trading Interval in a Trading Week is 8:00-8:30 am on a Saturday, and the last Trading Interval is 7:30-8:00 am the following Saturday.

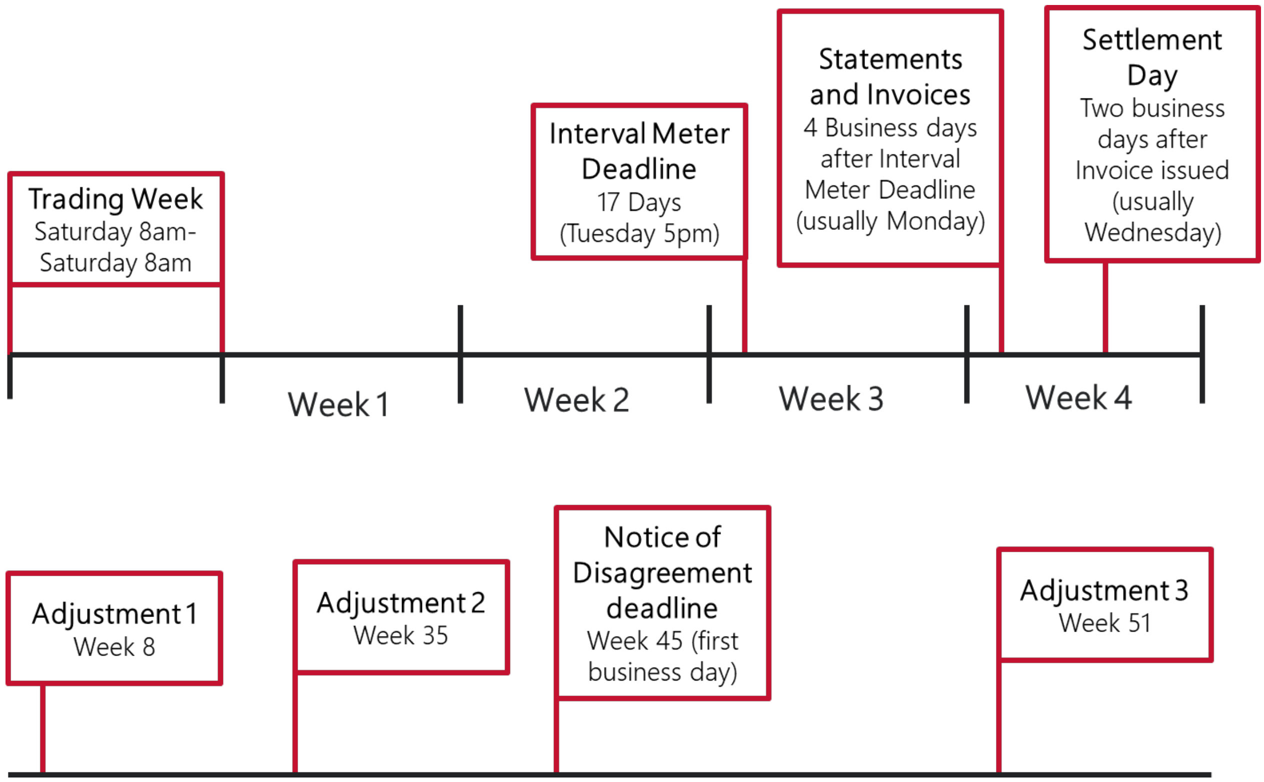
10.2.2 Settlement timeline

The weekly settlement timeline is illustrated in Figure 23:

[119] See clause 9.3 for more information on settlement timetables.

- The Interval Meter Deadline is 17 calendar days after the end of a Trading Week. This is the date by which the Meter Data Agent (Western Power) must submit all meter data pertaining to a Trading Week to AEMO. There are some manually read meters for which the Meter Data Agent is unable to submit meter readings within the required timeframe. For these meters, the Meter Data Agent submits estimated readings by the Interval Meter Deadline, which are then substituted with actual readings in the first adjustment (see below).
- AEMO sends Settlement Statements and Invoices to Rule Participants four Business Days after the Interval Meter Deadline. Settlement Statements contain detailed breakdowns of various settlement amounts, while the Invoice is a tax invoice setting out the amount payable or receivable.
- Settlement Day occurs two Business Days after AEMO has sent out Settlement Statements and Invoices. Participants owing money to AEMO must ensure cleared funds are transmitted to AEMO by this date, while AEMO must ensure that it transmits cleared funds to Participants it owes money to.
- AEMO conducts three adjustments to the initial settlement for a Trading Week to reflect missing or incorrect meter data, and resolution of disagreements and errors. These adjustments occur 8, 35, and 51 weeks after the end of a Trading Week (so that a Trading Week is completely settled within a 12-month period).
- Where a Participant disagrees with a settlement quantity, it must lodge a disagreement no later than 45 weeks after the end of the relevant Trading Week. This is to ensure AEMO has sufficient time to incorporate any disagreements into scheduled adjustments, including up to the final adjustment. If a Participant is unable to get resolution through the disagreements process (for example, it disagrees with AEMO's resolution of the issue in an adjustment), it can escalate the issue to the dispute resolution mechanism (see Section 4.5).

Figure 23 Settlement timeline



AEMO annually publishes detailed settlement timelines for a Financial Year that sets out the exact dates associated with activities to be performed by AEMO or Market Participants in relation to settlement functions.

10.3 Metered Schedules[120]

The Meter Data Agent (Western Power) submits meter data to AEMO on a weekly basis to facilitate settlement (see above). AEMO uses the meter data to calculate Metered Schedules for all Registered Facilities[121] and Non-Dispatchable Loads. The Metered Schedule of a Facility for a Trading Interval reflects its loss-adjusted meter reading for that Trading Interval. AEMO performs the loss adjustment by applying static Loss Factors[122] to the unadjusted meter reading, so that it is loss-adjusted to the Reference Node (see also Section 9.3.1).

AEMO calculates Metered Schedules for Non-Dispatchable Loads, which provides the loss-adjusted metered quantities for sites with interval meters (including Contestable Customers). However, AEMO does not receive meter data for the Captive Customers served by Synergy[123], so AEMO must calculate the aggregate loss-adjusted metered quantities associated with Synergy's Captive Customers. AEMO does this through the concept of the Notional Wholesale Meter. AEMO calculates a single Metered Schedule for the Notional Wholesale Meter (representing Synergy's Captive Customers) by taking the difference between the Metered Schedules where energy is consumed and the Metered Schedules where energy is produced.

There are special Metered Schedule calculations for Intermittent Loads. The value measured by the meter at the site is split into several parts:

- Injection is associated with the Registered Facility.
- Withdrawal is associated with a separate Non-Dispatchable Load.
- For grandfathered Intermittent Loads (see section 5.2.4), Withdrawal will be split into an Intermittent Load component (which is used for Reserve Capacity settlement calculations) and a Non-Intermittent Load component.

Complex metering situations (e.g., a separately metered Non-Dispatchable Load within an embedded network) are handled on a case-by-case basis.

Metered Schedules are a fundamental component of settlement, as they are the primary determinant of energy settlement amounts, and an important factor in cost recovery for some ESS and Market Fees.

10.4 Settlement amounts

AEMO is responsible for calculating settlement amounts which reflect AEMO's liability to a participant or a participant's liability to AEMO, in respect of WEM transactions occurring over a Trading Week.

[120] See clause 9.5 of the WEM Rules.

[121] This excludes DSPs (which are settled for Reserve Capacity payments only) and Interruptible Loads (which are settled on ESS enablement quantities only).

[122] Determined by Western Power.

[123] End-use customers with an annual consumption of below 50 MWh are Captive Customers that are served by Synergy by default.

Settlement amounts comprise six segments pertaining to:

- The STEM.
- The RCM.
- The energy component of the RTM.
- The ESS component of the RTM.
- Market Fees covering the cost of participation.
- Outage Compensation.

Table 6 summarises the key components of each segment and the parties that AEMO collects funds from and pays funds to.

In addition to the segments below, sometimes AEMO must administer ad-hoc payments when a Market Participant has paid a Financial Penalty (that is, a Civil Penalty or an Infringement, see Section 4.4). When this happens, AEMO must distribute the Financial Penalty via the settlement process to all other Market Participants other than the participant to whom the penalty was issued. The penalty is distributed to eligible Market Participants in proportion to the absolute value of their Metered Schedules over the previous 12-month period.

Table 6 Overview of settlement segment and amounts

<table>
<tr><th>Settlement segment</th><th>Description</th><th>Paid to</th><th>Recovered from</th></tr>
<tr><td>Short-Term Energy Market</td><td>Settled based on scheduled offers and bids, and STEM Price from STEM Auction.
Does not require Metered Schedules as settlement amounts are based on STEM Auction results.
See clause 9.7 of the WEM Rules for STEM segment calculations.</td><td>Market Participants who have a positive STEM Quantity (net seller)</td><td>Market Participants who have a negative STEM Quantity (net purchaser)</td></tr>
<tr><td>Reserve Capacity</td><td>Reserve Capacity settlement comprises two components:
• Payments to capacity providers
• Payments from capacity purchasers
See clause 9.8 of the WEM Rules for STEM segment calculations.</td><td>Capacity providers are those Market Participants who have been assigned Capacity Credits. Payments to providers comprise:
• A payment for capacity based on
– Capacity Credits assigned to the participant's Facilities (see Section 7.4.3)
– Capacity Credits allocated from the participant's Facilities to another participant; this quantity is netted off the total Capacity Credits held by the participant (see Section 7.9)
– The Reserve Capacity Price associated with the participant's Facilities (see Section 7.6)
• Capacity refunds charged to the participant for failing to meet its RCOQs (see Section 7.4.3)
• Capacity refund rebates returned to capacity providers (see Section 7.4.3)
• supplementary capacity payments (see Section 7.7)
• Excess allocation payments, where a participant has been allocated Capacity Credits over and above their IRCR</td><td>Payments to capacity providers are cost-recovered via:
• The Targeted Reserve Capacity Cost which is allocated to participants who have been unable to secure sufficient allocation of Capacity Credits to fully cover their IRCR (see Section 7.8.2)
• The Shared Reserve Capacity Cost, which is the cost of surplus Capacity Credits procured by AEMO over and above the Reserve Capacity Requirement, as well as the cost of supplementary capacity. This is allocated to all Market Participants in proportion to their IRCR (see Section 7.8.2).</td></tr>
<tr><td>Energy</td><td>Energy settlement comprises two components:
• Energy payments settled based on a participant's Metered Schedule, its NCP, and the Reference Trading Price for a Trading Interval.
– The Reference Trading Price for a 30-minute Trading Interval is the average of the five-minute Market Clearing Prices for energy calculated by the Dispatch Algorithm for all Dispatch Intervals contained in the Trading Interval
– The NCP reflects the participant's level of Bilateral Contract coverage and can reduce exposure to the market price.</td><td>• Energy payments are paid to Market Participants who are Injecting in a Trading Interval, based on their Metered Schedule and NCP.
• Energy Uplift Payments are paid to Market Participants whose Facilities are dispatched behind a binding Network Constraint, and whose marginal cost of generation exceeds the Reference Trading Price in a Dispatch Interval.</td><td>• Energy payments are recovered from all Market Participants who are consuming in a Trading Interval, based on their Metered Schedule and NCP.
• Energy Uplift Payments are recovered from all Market Participants who are consuming in a Trading Interval in proportion to their consumption.</td></tr>
</table>

Settlement segment	Description	Paid to	Recovered from
	• Energy Uplift Payment. This is a payment made to compensate (or make whole) energy producers who are dispatched behind a binding Network Constraint, because of which their marginal cost of generation exceeds the Reference Trading Price in a Dispatch Interval. Energy Uplift Payments are described in further detail in Section 10.4.1 below See clause 9.9 of the WEM Rules for RTM segment calculations.		
Essential System Services	Three groups of ESS are settled in the WEM: • FCESS comprises Contingency Reserve Raise, Contingency Reserve Lower, RoCoF Control Service, Regulation Raise and Regulation Lower • System Restart Services • NCESS See clause 9.10 of the WEM Rules for ESS segment calculations.	There are three components to payments made to Market Participants who provide FCESS • A real-time component, which is based on the quantity of FCESS their Facilities were enabled for in a Dispatch Interval and the prevailing Market Clearing Price for that FCESS • A SESSM component that exists only if the SESSM is triggered for that FCESS, and a SESSM Award is made to a Facility that did not previously provide FCESS. The SESSM component comprises a fixed Availability Payment and a refund component (where the Participant fails to meet their SESSM availability obligations). See also Sections 0 and 0 for more details on Availability Payments and SESSM refunds. • An FCESS Uplift Payment component which compensates FCESS Providers for Enablement Losses if their Facility is constrained on to their Enablement Minimum levels to provide FCESS, and the Energy Market Clearing Price is insufficient to recover energy production costs. FCESS Uplift Payments are detailed further in Section 10.4.2. Providers of System Restart Services are paid a fixed amount per Trading Interval as contractually agreed between the provider and AEMO. Only NCESS procured by AEMO is settled through the WEM. NCESS providers are paid a quantity per Trading Week as contractually agreed between the provider and AEMO.	ESS payments are recovered from Market Participants in accordance with cost recovery methodologies set out in the WEM Rules – see Section 6.3 for a summary of how costs are recovered. See Sections 10.4.3 and 10.4.4 below for further details on the approach to Contingency Reserve Raise and RCS cost recovery.
Market Fees	Market Fees are calculated in $/MWh using separate fee rates for AEMO, the Coordinator and the ERA (see Section 4.6) See clause 9.12 of the WEM Rules for Market Fees calculations.	Paid to AEMO, the Coordinator and the ERA	Recovered from all Market Participants by applying the relevant Market Fee rate to the absolute value of their Metered Schedules

Settlement segment	Description	Paid to	Recovered from
Outage Compensation	Market Participants who have had their Outages recalled at short notice (within 48 hours of Outage Commencement) by AEMO can apply for compensation. If AEMO accepts the claim, then AEMO determines a compensation amount and then converts that to per Trading Interval quantities for settlement. See clause 9.11 of the WEM Rules for Outage Compensation calculations.	Market Participants who have lodged an Outage Compensation claim and have had the claim accepted by AEMO.	All Market Participants in proportion to their consumption in the Trading Intervals for which AEMO has calculated a compensation quantity.

10.4.1 Energy Uplift Payment[124]

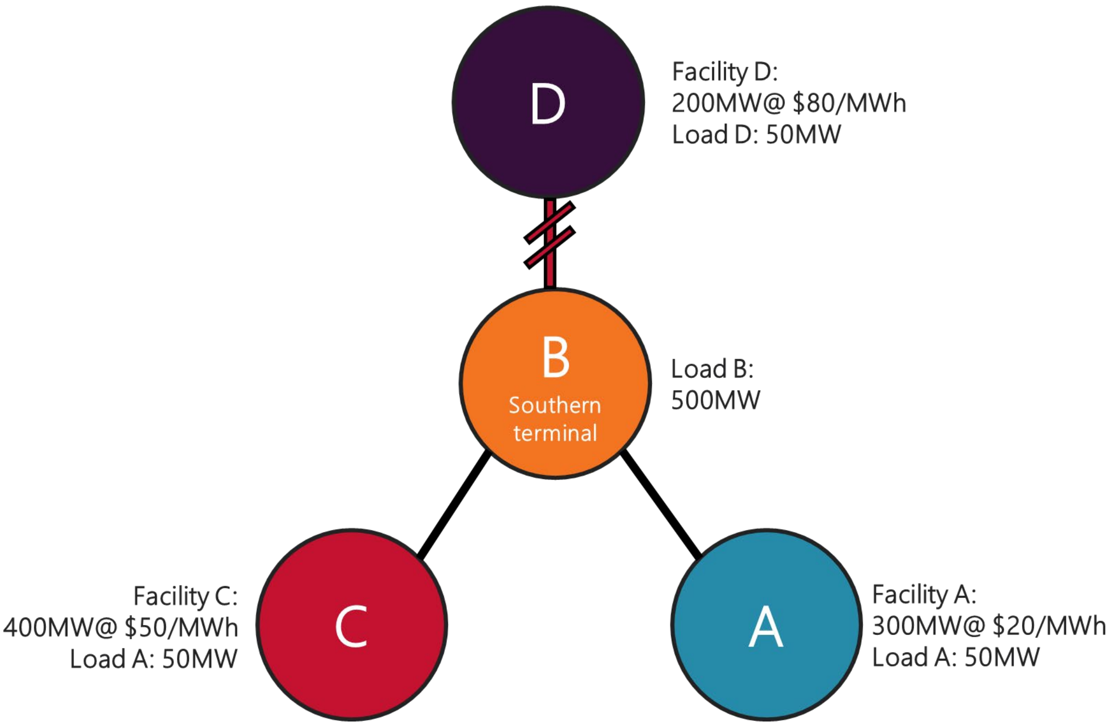
As discussed in Section 8.3, the Dispatch Algorithm clears energy offers to maximise welfare or minimise overall cost, while ensuring Network Constraints not violated.

The Market Clearing Price for energy is based on the marginal cost of supplying the Reference Node.

This means that when there is a binding Network Constraint, Facilities may be dispatched at a marginal cost higher than the Market Clearing Price to meet the local load. This situation is known as 'mispricing' and is illustrated in Figure 24 below.

In this example, the Reference Node is B, and there is a binding Network Constraint preventing the flow of energy from node B to node D. As a result, Facility D is dispatched for 50 MW (at a Marginal Offer Price of $80) to ensure the demand at node D is met. However, the marginal Facility at the Reference Node is Facility C (Facility C will supply the next increment of load at node B). Hence, the Market Clearing Price is set by Facility C's Marginal Offer Price, which is $50. Without an Energy Uplift Payment, Facility D will receive a price of $50, which is less than its Marginal Offer Price of $80. Hence, Facility D is mispriced, and must be 'uplifted' to ensure it receives a price of $80 for the relevant Dispatch Interval.

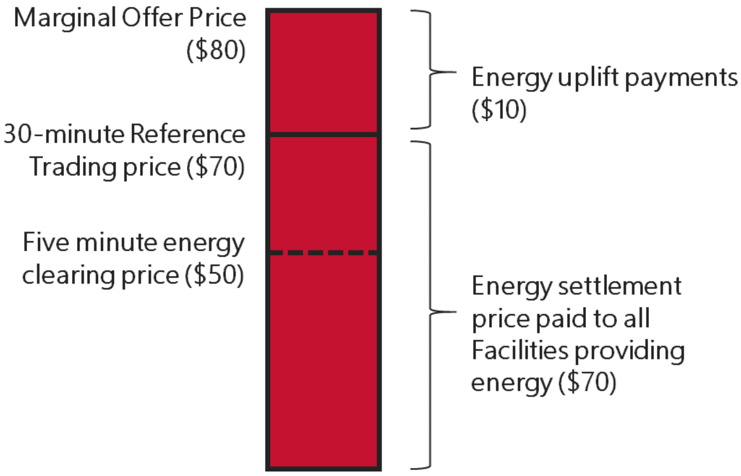
Figure 24 Example of mispricing



The Energy Uplift Payment mechanism gets triggered when a binding constraint causes the type of mispricing illustrated above to arise. When the mechanism is triggered in a Dispatch Interval, AEMO:

[124] Energy Uplift Payment calculations are detailed in clauses 9.9.6 to 9.9.15 of the WEM Rules.

Figure 25 Example of Uplift Price calculation



- Calculates a $/MWh Energy Uplift Price that denotes the price differential the Facility must be paid to make it whole. This is the difference between the mispriced Facility's Marginal Offer Price in that Dispatch Interval, and the Reference Trading Price in the relevant Trading Interval. Even though the Facility is mispriced relative to the Market Clearing Price, it is made whole relative to the Reference Trading Price, as that is the prevailing settlement price for any Dispatch Interval within a given Trading Interval (see Figure 25). Where the Reference Trading Price is greater than the mispriced Facility's Marginal Offer Price, the Facility does not need to be uplifted, as the settlement price is sufficient to cover its running costs in the mispriced Dispatch Interval.
- Calculates an Energy Uplift Quantity by estimating the mispriced Facility's generation output in that Dispatch Interval. AEMO does not have access to meter data for each five-minute interval, so must apportion the Facility's 30-minute Metered Schedule into five-minute Dispatch Intervals using five-minute SCADA readings.
- Calculates an Energy Uplift Payment by multiplying the Energy Uplift Price by the Energy Uplift Quantity.

Facilities are not eligible for uplift payments if they are:

- downwards ramp rate constrained;
- constrained by an ESS Enablement Minimum; or
- providing NCESS.

10.4.2 FCESS Uplift Payments[125]

Market Participants who are scheduled to provide FCESS must be dispatched for Energy to at least their Enablement Minimum level. When a Market Participant is constrained on for Energy to their Enablement Minimum level to provide one or more FCESS, the resulting Energy Market Clearing Price and relevant FCESS Market Clearing Prices may be insufficient to enable the Market Participant to recover their energy production costs. These losses are referred to as Enablement Losses.

FCESS Uplift Payments ensure that FCESS providers are able to recover their energy production costs when they are constrained on to their Enablement Minimum levels to provide FCESS.

In this section, we provide an example of how FCESS Uplift Payments are calculated when a Market Participant is providing multiple FCESS. Appendix A contains further examples of how FCESS Uplift Payments are calculated; however, these are limited to cases where the Market Participant is providing a single FCESS.

[125] FCESS Uplift Payment calculations are detailed in clauses 9.103A to 9.103H of the WEM Rules.

Example

In this example, in a given Dispatch Interval, a Market Participant is offering Energy, Contingency Reserve Raise, and Regulation Raise from a single Facility with nameplate capacity of 200MW and offers as indicated below.

	Energy	Contingency Reserve Raise	Regulation Raise
Offer Price	$50/MWh	$0/MW	$5/MW
Quantity Offered	100MW	25MW	25MW
Enablement Minimum		50MW	50MW

The Facility is cleared as follows:

	Energy	Contingency Reserve Raise	Regulation Raise
Quantity cleared (MW)	50MW	25MW	15MW
Quantity cleared (MWh)[126]	0.8333	0.4167	0.25
Market Clearing Price	$10	$5	$10

The Market Participants total costs with respect to the Facility are given by multiplying their cleared quantities by the relevant offer prices. Hence, the Market Participant incurs $43 in costs $(0.8333 \times \$50 + 0.4167 \times \$0 + 0.25 \times \$5)$

The Market Participants total revenues with respect to the Facility are given by multiplying their cleared quantities by the relevant Market Clearing Prices. Hence, the Market Participant earns revenues of $13 $(0.8333 \times \$10 + 0.4167 \times \$5 + 0.25 \times \$10)$

Without any FCESS Uplift Payments, the Market Participants incurs a loss of $30 $(\$13 - \$43)$.

The FCESS Uplift Payment for the Facility is calculated as follows:

- Enablement Losses are first calculated for each FCESS provided by the Facility. A Facility that has not been enabled for the relevant FCESS or has already been paid an Energy Uplift Payment is ineligible to receive an FCESS Uplift Payment. Otherwise, the FCESS Uplift Payment is calculated by multiplying the Enablement Minimum level for the relevant FCESS by the difference between the Energy Market Clearing Price and the Facility's Energy Offer Price applicable to that Enablement Minimum level. In this example, the Facility has an Enablement Minimum of 50MW for both Contingency Reserve Raise and Regulation Raise; hence its Enablement Losses for both FCESS is $166.67[127] $(50MW \times (\$50 - \$10) \times (5/60))$.
- The FCESS Uplift Payment payable to the Facility in the given Dispatch Interval is calculated as the maximum of all Enablement Losses incurred by the Facility for each FCESS provided (as otherwise the Market Participant would be compensated multiple times and over-paid). In this example, the FCESS Uplift Payment to the Facility is $166.67 $(Max(\$166.67, \$166.67))$.

For cost recovery purposes, AEMO needs to allocate the $166.67 FCESS Uplift Payment across the relevant FCESS services; AEMO does this by dividing the FCESS Uplift Payment payable to a Facility by the number of FCESS provided by the Facility with non-zero enablement. In this example, the Facility has been enabled for a non-zero quantity for two FCESS: Contingency Reserve Raise and Regulation Raise.

[126] The quantity cleared in MWh is calculated by multiplying the cleared MW quantities by 5/60 to convert an hourly quantity to a five-minute quantity.

[127] In this simplified example, we assume the Facility has a Loss Factor of 1; in practice the Enablement Losses are also multiplied by the Facility Loss Factor to convert the Enablement Minimum quantity to a sent-out value.

Hence, the cost recoverable quantity for each FCESS is \$83.33 ($\$166.67 \div 2$). That is, \$83.33 of the \$166.67 FCESS Uplift Payment to the Facility will be recovered through the Contingency Reserve Raise cost allocation methodology while the remaining \$83.33 will be recovered through the Regulation ESS cost recovery methodology[128].

10.4.3 Runway allocation[129]

The runway allocation method is used to allocate the costs per Dispatch Interval of procuring:

- Contingency Reserve Raise; and
- The Additional RoCoF Requirement component of RCS. As noted in Section 8.4, this is a substitute for Contingency Reserve Raise, and can be used to meet the Contingency Reserve Raise Requirement in a given Dispatch Interval, so is cost-recovered on the same basis.

The rest of this section refers to the above jointly as 'Contingency Reserves'.

As noted in Section 8.3, the Contingency Reserve Raise requirement is set by the Largest Credible Supply Contingency, which can be:

- An energy producing Facility (that is, a Facility Contingency representing loss of generation from a single Facility). The amount of energy and ESS (Contingency Reserve Raise) cleared in the RTM that could be lost as a result in the relevant Dispatch Interval is the Facility Risk.
  - If a Facility Contingency sets the Contingency Reserve Raise Requirement, the costs of procuring contingency reserves are recovered using the runway method from all energy producing Facilities that were cleared for more than 10 MW of energy in relevant Dispatch Interval.
- A Network Contingency representing the loss of one or more injecting Facilities due to loss of one or more lines. The amount of cleared energy, ESS (Contingency Reserve Raise), and load that could be lost as a result is the Network Risk.
  - If a Network Contingency sets the Contingency Reserve Raise Requirement, the costs of procuring Contingency Reserves are split into two components as described below and shown in Figure 26[130].
    - A Facility component recovered as above from all energy producing Facilities that were cleared for more than 10 MW of energy.
    - A Network component recovered using the runway method from all energy producing Facilities (cleared for more than 10 MW of energy), which would be disconnected as a result of the Network Contingency manifesting (that is, the relevant lines disconnecting). The magnitude of the network component reflects the delta between the Largest Network Risk and the Largest Facility Risk.

Embedded generating systems serving Intermittent Loads are included in the runway calculation in one of two ways:

1. Where a site has protection systems such that any generation Outage does not affect the overall consumption of the Facility by more than 10 MW (i.e., it will be offset by an automatic reduction in load,

[128] See Table 6 for a summary of how different FCESS are cost-recovered.

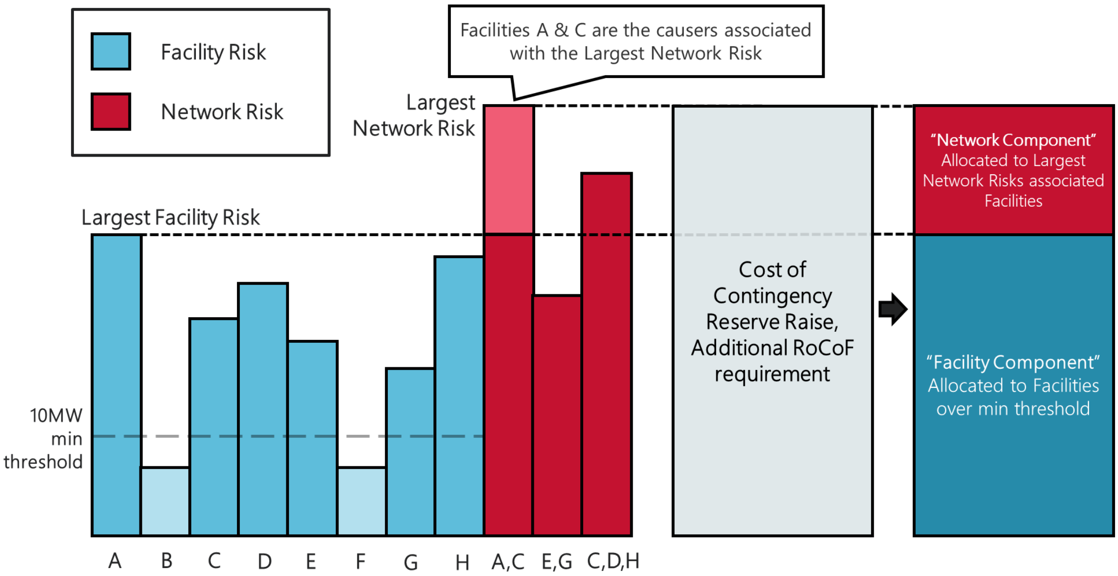
[129] See also Appendix 2A of the WEM Rules.

[130] If there are two or more Network Contingencies that are tied, in that they all have the Largest Network Risk, then the Network Component is shared equally amongst the tied contingencies. The causers of each Network Contingency are allocated the relevant tied share using the runway method.

or an automatic increase from other embedded generation at the site), the whole Facility will be included as a single entry represented by its net Injection into the Network.

2. Where such protection systems are not in place (i.e., an Outage of an embedded generating unit at the site would result in a change to the net consumption of more than 10 MW), then each individual generating unit at the site is included separately according to its as-generated MW[131].

Figure 26 Allocation of costs to Facility Risks and Network Risks



The runway method allocates Contingency Reserve costs to causers of contingencies, commensurate with the extent to which they have contributed to the *additional* procurement Contingency Reserve Raise Requirement.

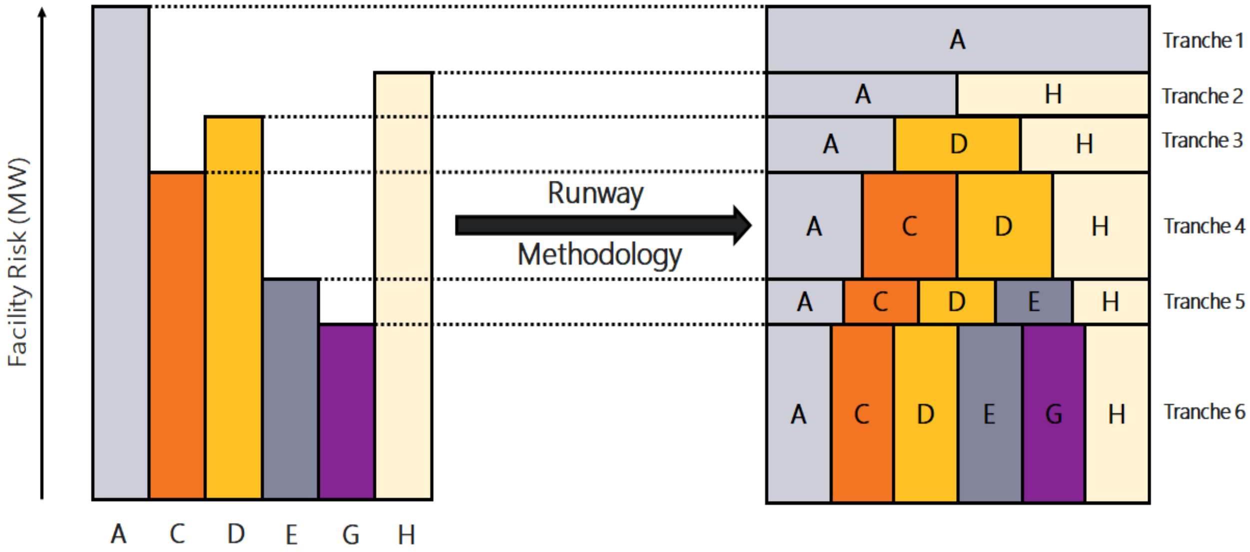
This is illustrated in the example below where six Facilities (A, C, D, E, G and H from Figure 26) have been cleared for more than 10 MW of energy and are deemed causers of the Facility component of the Contingency Reserve costs. In this example, the Contingency Reserve costs are allocated in six tranches (or shares):

- The first tranche reflects the difference between A's Facility Risk and H's Facility Risk, where H is the second largest Facility Risk. This tranche is allocated only to A. This is because if A was not generating, then this quantity of reserve would not have been procured.
- The second tranche reflects the difference between H's Facility Risk and D's Facility Risk, where D is the third largest Facility Risk. This tranche is allocated equally to Facilities A and H. This is because if Facilities A and H were not generating, then this quantity of reserve delta would not have been procured.
- The third tranche reflects the difference between D's Facility Risk and C's Facility Risk, where C is the fourth largest Facility Risk. This tranche is allocated equally to Facilities A, H, and D.
- The subsequent tranches are similarly allocated until the sixth tranche (which denotes the output of the smallest Facility Risk) is allocated equally across all six Facilities.

A given Facility's share of the cost can be calculated by summing its share across all six tranches.

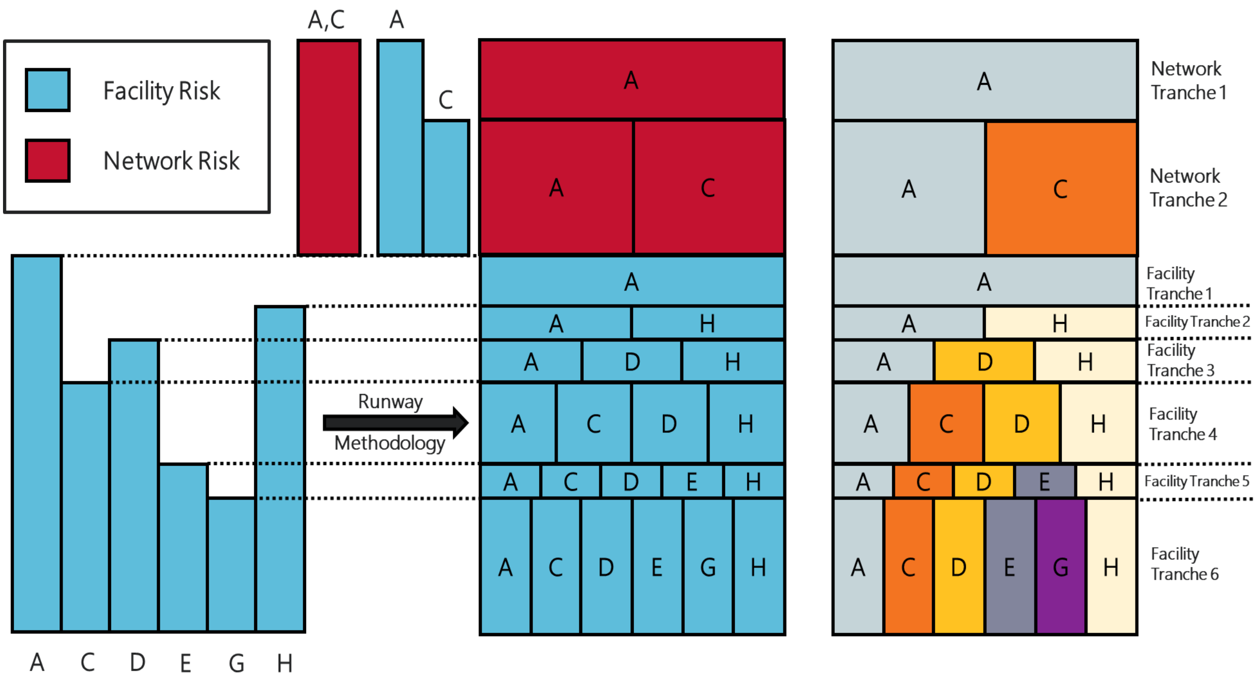
[131] Unless the total Injection from the site is greater than the largest output from any individual generating unit, in which case the Facility will be included as a whole for its total net Injection.

Figure 27 Example of runway method of allocating Facility component of Contingency Reserve costs



The above example shows how the Facility component of Contingency Reserve costs are allocated. The Network component is allocated in a similar manner to the causers of the Network Contingency that sets the Contingency Reserve Requirement; this means the causer Facilities pay two shares: one share pertaining to the Facility component and another to the network component. This is illustrated in Figure 28 below.

Figure 28 Example of runway method of allocating Facility and network components of Contingency Reserve costs



10.4.4 RoCoF cost recovery[132]

The rules discussed in this section are currently under review by EPWA. This section will be revised in a future release as more information becomes available.

The cost per Trading Interval of procuring the Minimum RoCoF Control Requirement component of RCS (shortened to 'RCS costs' in this section) is allocated in equal shares across three potential groups of causers:

- The Network Operator (Western Power) is allocated a one-third share of the Trading Interval cost.
- Registered Facilities that inject into (or generate energy in) the WEM are allocated a one-third share of the Trading Interval cost in proportion to the absolute value of their Metered Schedule in that Trading Interval.
- Non-Dispatchable Loads and Registered Facilities comprising only Scheduled Loads are allocated a one-third share of the Trading Interval cost in proportion to the absolute value of their Metered Schedule in that Trading Interval.

If a causer can provide evidence sufficient to accredit its Facility for a RoCoF Ride-Through Capability higher than 0.5 Hz per 500 milliseconds above the RoCoF Safe Limit (the Safe Limit being the limit under which AEMO operates the system) without adverse impacts (e.g. disconnection or damage to the Facility), it is not required to contribute towards RCS costs. Where there are no members of a particular causer group who are required to contribute, the RCS costs are allocated to members of the remaining causer groups. For example, if the Network Operator has demonstrated sufficient ride-through capability for its Distribution and Transmission Facilities, the cost will be shared in equal halves across non-exempt energy producers and energy consumers.

10.5 Default[133]

Default rules apply in the event of a Market Participant failing to meet its settlement obligations (e.g., where a participant fails to or is unable to make payment on settlement day or fails to meet a Prudential Obligation).

In the event of non-payment on settlement day, AEMO will deem the Market Participant to be in default and may draw down on Credit Support that it holds on behalf of the Market Participant. The Market Participant would be given at least one Business Day (and at AEMO's discretion, up to five Business Days) to rectify the situation. If the situation is not rectified, the Market Participant may, at AEMO's discretion, be fully or partially suspended from participation in the WEM.

If, following a default event, the market lacks adequate funds to settle, the shortfall is first allocated to Market Participants in proportion to what they would have been paid if there was no shortfall. Subsequently, the shortfall is reallocated based on a levy collected several days after the default and allocated across all Market Participants based on their Metered Schedules in the most recently settled Trading Week. If the defaulting participant eventually pays its outstanding obligations, the levy will be

[132] See also Appendix 2B of the WEM Rules.

[133] See clause 9.20 of the WEM Rules.

refunded. At the end of each Financial Year, the Default Levy will be reallocated between Market Participants based on their Metered Schedules over the year. This end-of-year adjustment ensures participants do not avoid funding a default simply because they do not happen to be producing or consuming in the month in which the default occurred.

A1. Overview of market processes

The information in this section is provisional and has been drafted with consideration to Taskforce decisions published on the EPWA website. This section will be revised in a future release as more information becomes available.

The table below provides an overview of market processes mapped against the administrator of the process, and the parties who are involved in the process.

Market Process	Administrator of process				Parties to process					
	AEMO	The Coordinator of Energy	ERA	Network Operator	AEMO	The Coordinator of Energy	ERA	Network Operator	Market Participants selling WEM services	Market Participants consuming WEM services
Rule Changes		x			x	x	x	x	x	x
Changes to WEM Procedures	x	x	x	x	x	x	x	x	x	x
Negotiating and approving Generator Performance Standards				x		x		x	x	
Registering as Rule Participant	x							x	x	x
Facility Registration	x							x	x	x
Reserve Capacity Procurement (Certification and assignment of Capacity Credits)	x							x	x	
IMLs/New IMLs TBD										
Supplementary Capacity Procurement	x								x[134]	
Non-Co-optimised Essential System Services	x	x		x	x	x	x	x	x[135]	

[134] Supplementary Capacity can also be provided by entities that are not a registered Rule Participant.

[135] NCESS can also be provided by entities that are not a registered Rule Participant

Market Process	Administrator of process				Parties to process					
	AEMO	The Coordinator of Energy	ERA	Network Operator	AEMO	The Coordinator of Energy	ERA	Network Operator	Market Participants selling WEM services	Market Participants consuming WEM services
Standing Data Submissions	x							x	x	x
Bilateral Contract Data Submission	x								x	
Short Term Energy Market	x								x	x
Real-Time Market Submissions	x								x	x
Real-Time Market Schedules (including pricing of energy and ESS)	x								x	x
Energy and ESS Dispatch	x								x	x
Manage PSS and PSR	x								x	
Procure Supplementary ESS (via SESSM)	x						x		x	
Settlement	x				x	x	x	x	x	x
Prudential Requirements	x							x	x	x
Compliance Monitoring – GPS	x								x	
Compliance Monitoring – Dispatch	x								x	x
Compliance Monitoring – other			x		x			x	x	x
Market Surveillance and Monitoring	x (supports ERA)		x						x	x
Market effectiveness monitoring		x			x		x			
Outage planning	x							x	x	

Market Process	Administrator of process				Parties to process					
	AEMO	**The Coordinator of Energy**	**ERA**	**Network Operator**	**AEMO**	**The Coordinator of Energy**	**ERA**	**Network Operator**	**Market Participants selling WEM services**	**Market Participants consuming WEM services**
Facility Testing – Commissioning and Reserve Capacity Tests	x								x	
10-year Transmission Planning (TSP), published annually				x	x	x			x	x
10-year Generation Planning (LT-PASA), published annually	x							x	x	x
20-year Whole of System Planning (WOSP), published every five years		x			x			x	x	x
3-year Capacity Planning (MT-PASA), published weekly	x							x	x	x
1-week Capacity Planning (ST-PASA), published daily	x							x	x	x

A2. Enablement Limit examples

This appendix provides further examples of market clearing outcomes, extending the examples provided in Section 8.5 to explore the interaction of binding minimum enablement constraints on pricing dynamics and implications for offer construction. These examples can be seen as iterations of market outcomes as Facility 1 adjusts its offers in response to projected market outcomes in the Pre-Dispatch Schedule.

Example 3: Reserve price is zero with Enablement Limits, single provider

In this example, we adjust the offer prices (so that the Facility 1 is more expensive for energy than Facility 2) and introduce a minimum Enablement Limit for Facility 1 (as discussed in Section 5.6.1). To ensure a feasible dispatch outcome, the Dispatch Algorithm includes a new constraint that makes sure Facility 1 is dispatched for energy to at least its minimum Enablement Limit.

Inputs

System parameters	
Energy demand	100 MW
Reserve requirement	25 MW

Facility 1 parameters		
Maximum capacity		50 MW
Enablement Minimum		**20 MW**
	Price ($/MW)	**Quantity (MW)**
Energy offer	500	50
Reserve offer	0	**30**

Facility 2 Parameters		
Maximum capacity		100 MW
	Price ($/MW)	**Quantity (MW)**
Energy offer	100	100
Reserve offer	0	0

Optimisation problem

The optimisation problem is the same as for examples 1 and 2, with an additional constraint to set the minimum energy dispatch level for Facility 1. In the actual Dispatch Algorithm, such constraints are only included if the Facility is already Injecting above the minimum enablement level.

Equation 11: Minimum Enablement Limit constraint

$$energyDispatch_{Facility1} \geq minimumEnablementLimit_{Facility1}$$

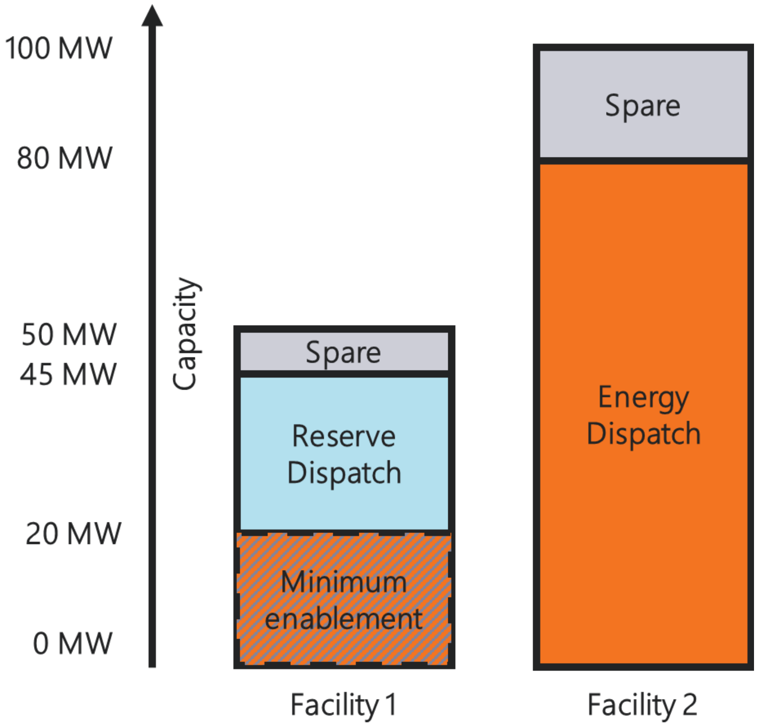
Outputs

Dispatch

Facility 1 is the sole reserve provider, so it is dispatched for 25 MW of reserve. Even though Facility 1 is more expensive than Facility 2 for energy, the minimum Enablement Limit constraint requires that it be cleared for 20 MW of energy. The cheapest way to meet the remaining energy demand is to dispatch Facility 2.

- Facility 1 Energy dispatch: 20 MW, reserve dispatch: 25 MW.
- Facility 2 Energy dispatch: 80 MW, reserve dispatch: 0 MW.

Figure 29 Co-optimisation Example 3 dispatch



The total cost to serve load while meeting the reserve requirement is:

$$TotalCost = (20 \times \$500) + (80 \times \$100) + (25 \times \$0) + (0 \times \$0) = \$18{,}000$$

Marginal prices

The marginal prices are based on the additional cost of serving another increment of the service. Facility 2 is the marginal Facility for energy. Facility 1 is the marginal Facility for reserve.

- *Energy*: If demand increased by 1 MW (to 101 MW), Facility 2 would provide it, with no other changes to dispatch.

  $$TotalCost = (20 \times \$500) + (\mathbf{81} \times \$100) + (25 \times \$0) + (0 \times \$0) = \$\mathbf{18,100}$$

  The change in total costs would be $100, and this is the marginal price for energy.

- *Reserve*: If the requirement were increased by 1 MW (to 26 MW), Facility 1 would provide it, with no other change to the dispatch.

  $$TotalCost = (20 \times \$500) + (80 \times \$100) + (\mathbf{26} \times \$0) + (0 \times \$0) = \$18{,}000$$

  The change in total costs would be $0, so this is the marginal price for reserve.

There is also a 'shadow price' relating to the minimum enablement constraint, but it does not flow through into the energy or reserve prices.

- Enablement Minimum at Facility 1: If the Enablement Limit increased by 1 MW (to 21 MW), Facility 1 would be dispatched for one more MW of energy (and Facility 2 backed off accordingly).

  $$TotalCost = (\mathbf{21} \times \$500) + (\mathbf{79} \times \$100) + (5 \times \$0) + (20 \times \$0) = \$\mathbf{18,400}$$

  The change in total costs would be $400, and this is the shadow price on the minimum enablement constraint for Facility 1.

Payments

Prior to applying FCESS Uplift Payments:

- Facility 1 revenue is $(20MW \times \$100) + (25MW \times \$0) = \$2{,}000$
- Facility 1 costs are $(20MW \times \$500) + (25MW \times \$0) = \$10{,}000$
- Facility 1 profit is $\$2{,}000 - \$10{,}000 = -\$8{,}000$. Facility 1 will require a FCESS Uplift Payment to recover its Enablement Losses (see below).
- Facility 2 revenue is $(80MW \times \$100) + (0MW \times \$0) = \$8{,}000$
- Facility 2 costs are $(80MW \times \$100) + (0MW \times \$0) = \$8{,}000$
- Facility 2 profit is $\$8{,}000 - \$8{,}000 = 0$. Facility 2 does not require a FCESS Uplift Payment as it is not providing FCESS.

Note that Facility 1 is receiving $100/MW while it costs $500/MW to run. It is *losing* money in the energy market because the effects of binding minimum enablement constraints do not flow through into the marginal prices, which reflect only the cost of the next increment of service.

Assuming that Facility 1 has not also received an Energy Uplift Payment, it is eligible to receive a FCESS Uplift Payment:

- Facility 1 has an Enablement Minimum of 20MW. Hence its Enablement Losses equal $8000 (20MW*($500/MW - $100/MW))[136].
- Assuming Facility 1 is only providing one FCESS, its FCESS Uplift Payment will equal $8000 which covers its initial losses of -$8,000[137].

Example 4: Reserve price is zero with Enablement Limits

This example is the same as Example 3, except that Facility 2 can provide reserve, and has a minimum Enablement Limit (as discussed in Section 5.6.1). To ensure a feasible dispatch outcome, the Dispatch Algorithm includes constraints that makes sure each Facility is dispatched for energy to at least its minimum Enablement Limit.

Inputs

System parameters	
Energy demand	100 MW
Reserve requirement	25 MW

Facility 1 parameters		
Maximum capacity	50 MW	
Enablement Minimum	20 MW	
	Price ($/MW)	**Quantity (MW)**
Energy offer	500	50
Reserve offer	0	30

Facility 2 parameters		
Maximum capacity	100 MW	
Enablement Minimum	**20 MW**	
	Price ($/MW)	**Quantity (MW)**
Energy offer	100	100
Reserve offer	0	**80**

[136] For simplicity, we have excluded the factor of 5/60 in the Enablement Loss calculation that converts MW quantities to MWh for settlement in all FCESS Uplift Payment examples in this appendix. See Section 10.4.2 for an example where the conversion factor is applied.

[137] See Section 10.4.2 for an example of how FCESS Uplift Payments are calculated for Facilities providing multiple FCESS.

Optimisation problem

The optimisation problem is the same as for Example 3, with an additional constraint to set the minimum energy dispatch level for Facility 2.

Equation 12: minimum Enablement Limit constraints

$$energyDispatch_{Facility1} \geq minimumEnablementLimit_{Facility1}$$

$$energyDispatch_{Facility2} \geq minimumEnablementLimit_{Facility2}$$

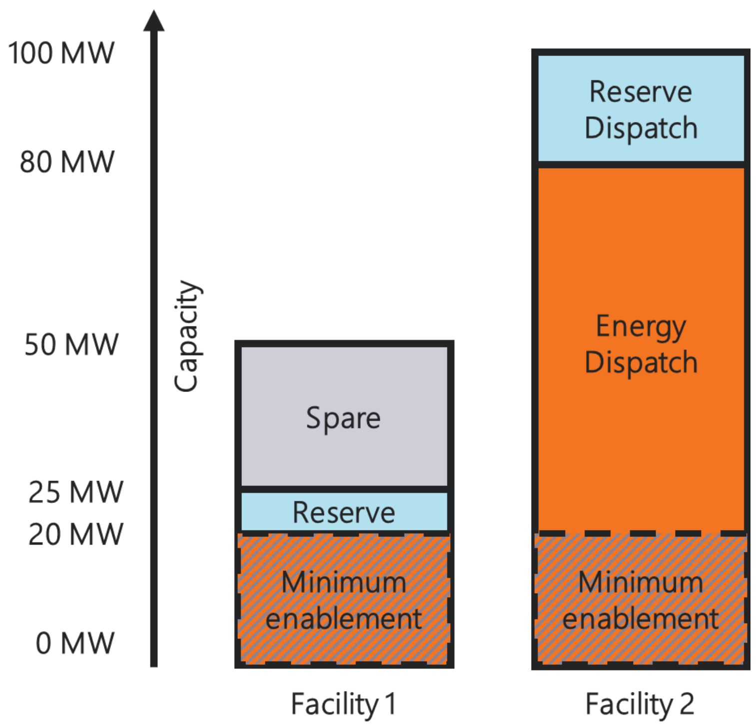
Outputs

Dispatch

Even though Facility 1 is more expensive than Facility 2, the minimum Enablement Limit constraint requires that it be cleared for 20 MW of energy. Facility 2 is also required to be cleared for at least 20 MW of energy, but is cleared for more because the cheapest way to meet the remaining energy demand is to dispatch Facility 2. The cost to dispatch either Facility for reserve is the same ($0), so the Dispatch Algorithm is indifferent to dispatching either. This example assumes it is allocated first to Facility 2, with Facility 1 providing the remainder.

- Facility 1 Energy dispatch: 20 MW, reserve dispatch: 5 MW.
- Facility 2 Energy dispatch: 80 MW, reserve dispatch: 20 MW.

Figure 30 Co-optimisation Example 4 dispatch



The total cost to serve load while meeting the reserve requirement is:

$$TotalCost = (20 \times \$500) + (80 \times \$100) + (5 \times \$0) + (20 \times \$0) = \$18{,}000$$

Marginal prices

The marginal prices are based on the additional cost of serving another increment of the service.

- *Energy*: If demand increased by 1 MW (to 101 MW), Facility 2 would back off provide it, and Facility 1 would provide the unit of reserve instead.

$$TotalCost = (20 \times \$500) + (\mathbf{81} \times \$100) + (\mathbf{6} \times \$0) + (\mathbf{19} \times \$0) = \$\mathbf{18,100}$$

  The change in total costs would be $100, and this is the marginal price for energy.

- *Reserve*: If the requirement were increased by 1 MW (to 26 MW), Facility 1 would provide it, with no other change to the dispatch.

$$TotalCost = (20 \times \$500) + (80 \times \$100) + (\mathbf{6} \times \$0) + (20 \times \$0) = \$18{,}000$$

  The change in total costs would be $0, so this is the marginal price for reserve.

The shadow price for each minimum enablement constraint is as follows:

- Enablement Minimum at Facility 1: If the Enablement Limit increased by 1 MW (to 21 MW), Facility 1 would be dispatched for one more MW of energy (and Facility 2 backed off accordingly)

$$TotalCost = (\mathbf{21} \times \$500) + (\mathbf{79} \times \$100) + (5 \times \$0) + (20 \times \$0) = \$\mathbf{18,400}$$

  The change in total costs would be $400, and this is the shadow price on the minimum enablement constraint for Facility 1.

- Enablement Minimum at Facility 2: If the Enablement Limit increased by 1 MW (to 21 MW), dispatch would not change, because the constraint is not binding.

$$TotalCost = (20 \times \$500) + (80 \times \$100) + (5 \times \$0) + (20 \times \$0) = \$18{,}000$$

  The total cost would stay the same, so the shadow price on the minimum enablement constraint for Facility 2 is 0.

Payments

Prior to applying FCESS Uplift Payments:

- Facility 1 revenue is $(20MW \times \$100) + (5MW \times \$0) = \$2{,}000$
- Facility 1 costs are $(20MW \times \$500) + (5MW \times \$0) = \$10{,}000$
- Facility 1 profit is $\$2{,}000 - \$10{,}000 = -\$8{,}000$. Facility 1 will require a FCESS Uplift Payment.
- Facility 2 revenue is $(80MW \times \$100) + (20MW \times \$0) = \$8{,}000$
- Facility 2 costs are $(80MW \times \$100) + (20MW \times \$0) = \$8{,}000$
- Facility 1 profit is $\$8{,}000 - \$8{,}000 = 0$

Again, Facility 1 is receiving $100/MW while it costs $500/MW to run. Facility 1 is losing money in the energy market, because the effects of binding minimum enablement constraints do not flow through into the marginal prices, which reflect only the cost of the next increment of service.

Assuming that Facility 1 has not also received an Energy Uplift Payment, it is eligible to receive a FCESS Uplift Payment:

- Facility 1 has an Enablement Minimum of 20MW. Hence its Enablement Losses equal $8000 (20MW*($500/MW - $100/MW)).

- Assuming Facility 1 is only providing one FCESS, its FCESS Uplift Payment will equal $8000 which covers its initial losses of -$8,000.

Example 5: Reserve price is zero with Enablement Limits

Examples 5 is the same as example 4, but with Facility 2 maximum capacity reduced by 5 MW. These examples demonstrate that breakeven point is driven by the quantity of service over which the Enablement Losses are recovered.

Inputs

System parameters	
Energy demand	100 MW
Reserve requirement	25 MW

Facility 1 parameters		
Maximum capacity	50 MW	
Enablement Minimum	20 MW	
	Price ($/MW)	**Quantity (MW)**
Energy offer	500	50
Reserve offer	0	30

Facility 2 parameters		
Maximum capacity	**95 MW**	
Enablement Minimum	20 MW	
	Price ($/MW)	**Quantity (MW)**
Energy offer	100	**95**
Reserve offer	0	**75**

Optimisation problem

The optimisation problem is the same as for Example 4.

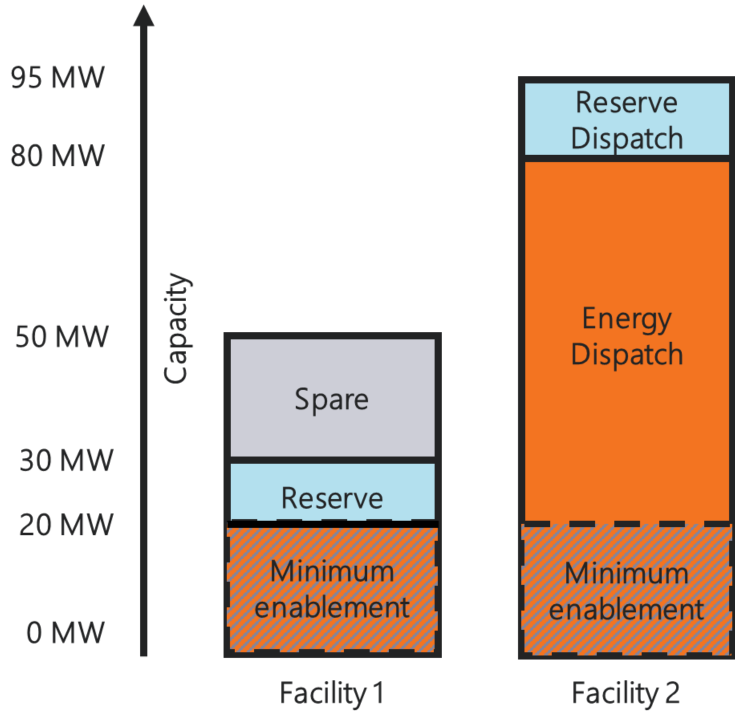
Outputs

Dispatch

Even though Facility 1 is more expensive than Facility 2, the minimum Enablement Limit constraint requires that it be cleared for 20 MW of energy. Facility 2 is also required to be cleared for at least 20 MW of energy but is cleared for more because the cheapest way to meet the remaining energy demand is to dispatch Facility 2. The cost to dispatch either Facility for reserve is the same ($0), so the Dispatch Algorithm is indifferent to dispatching either. This example assumes that it is allocated first to Facility 2, with Facility 1 providing the remainder.

- Facility 1 Energy dispatch: 20 MW, reserve dispatch: 10 MW.
- Facility 2 Energy dispatch: 80 MW, reserve dispatch: 15 MW.

Figure 31 Co-optimisation Example 5 dispatch



The total cost to serve load while meeting the reserve requirement is:

$$TotalCost = (20 \times \$500) + (80 \times \$100) + (10 \times \$0) + (15 \times \$0) = \$18{,}000$$

Marginal prices

The marginal prices are based on the additional cost of serving another increment of the service.

- *Energy*: If demand increased by 1 MW (to 101 MW), Facility 2 would increase energy output, reducing the amount of reserve it could provide, and Facility 1 would provide the unit of reserve instead.

  $$TotalCost = (20 \times \$500) + (\mathbf{81} \times \$100) + (\mathbf{11} \times \$0) + (\mathbf{14} \times \$0) = \$\mathbf{18,100}$$

  The change in total costs would be $100, and this is the marginal price for energy.

- *Reserve*: If the requirement were increased by 1 MW (to 26 MW), Facility 1 would provide it, with no other change to the dispatch.

  $$TotalCost = (20 \times \$500) + (80 \times \$100) + (\mathbf{11} \times \$0) + (10 \times \$0) = \$18{,}000$$

  The change in total costs would be $0, so this is the marginal price for reserve.

The shadow price for each minimum enablement constraint is as follows:

- Enablement Minimum at Facility 1: If the Enablement Limit increased by 1 MW (to 21 MW), Facility 1 would be dispatched for one more MW of energy (and Facility 2 backed off accordingly)

  $$TotalCost = (\mathbf{21} \times \$500) + (\mathbf{79} \times \$100) + (10 \times \$0) + (15 \times \$0) = \$\mathbf{18,400}$$

  The change in total costs would be $400, and this is the shadow price on the minimum enablement constraint for Facility 1.

- Enablement Minimum at Facility 2: If the Enablement Limit increased by 1 MW (to 21 MW), dispatch would not change, because the constraint is not binding.

$$TotalCost = (20 \times \$500) + (80 \times \$100) + (15 \times \$0) + (10 \times \$0) = \$18{,}000$$

The total cost would stay the same, so the shadow price on the minimum enablement constraint for Facility 2 is 0.

Payments

Prior to applying FCESS Uplift Payments:

Facility 1 revenue is $(20MW \times \$100) + (10MW \times \$0) = \$2{,}000$

Facility 1 costs are $(20MW \times \$500) + (10MW \times \$0) = \$10{,}000$

Facility 1 profit is $\$2{,}000 - \$10{,}000 = -\$8{,}000$. Facility 1 will require a FCESS Uplift Payment.

Facility 2 revenue is $(80MW \times \$100) + (15MW \times \$0) = \$8{,}000$

Facility 2 costs are $(80MW \times \$100) + (15MW \times \$0) = \$8{,}000$

Facility 2 profit is $\$8{,}000 - \$8{,}000 = 0$

Again, Facility 1 is receiving $100/MW while it costs $500/MW to run. Facility 1 is losing money in the energy market, because the effects of binding minimum enablement constraints do not flow through into the marginal prices, which reflect only the cost of the next increment of service.

Assuming that Facility 1 has not also received an Energy Uplift Payment, it is eligible to receive a FCESS Uplift Payment:

- Facility 1 has an Enablement Minimum of 20MW. Hence its Enablement Losses equal $8000 (20MW*($500/MW - $100/MW)).
- Assuming Facility 1 is only providing one FCESS, its FCESS Uplift Payment will equal $8000 which covers its initial losses of -$8,000.

Glossary

Defined terms from the WEM Rules have been capitalised. In these instances the definition as provided in the WEM Rules should be applied when reading this document. Some are paraphrased below for convenience.

Term	Definition
AEMO	Australian Energy Market Operator Limited
AGC	Automatic Generator Control
BRCP	Benchmark Reserve Capacity Price
CCGT	Combined-cycle gas turbine
Contingency Event	The failure or removal from service of one or more energy producing units, Facilities or Network Elements, or an unplanned change in load, Intermittent Generation, or other elements of the SWIS not controlled by AEMO
CRC	Certified Reserve Capacity
Credible Contingency Event	One or more Contingency Events that are reasonably possible in the prevailing circumstances.
DER	Distributed Energy Resources
DSM	Demand-side management
DSOC	Declared Sent Out Capacity as specified in a network access agreement
DSP	Demand Side Programme
Electric Storage Resource	A resource capable of receiving energy and storing it for later Injection
EOI	Expression of Interest to provide Reserve Capacity
EPWA	Energy Policy WA
ERA	Economic Regulation Authority
ESS	Essential System Services
FCESS	Frequency Co-optimised Essential System Services
FOS	Frequency Operating Standards
GPS	Generator Performance Standards
Intermittent Generating System	A generating system whose output cannot be reliably controlled, being dependent on a fuel source that is difficult to store and whose availability is difficult to predict (such as wind or sunlight)
IRCR	Individual Reserve Capacity Requirement
LRC	Low Reserve Condition
LRCD	Low Reserve Condition Declaration
NAQ	Network Access Quantity
NBP	Net Bilateral Position
NCESS	Non-Co-optimised Essential System Services
NCP	Net Contract Position
Non-Intermittent Generating System	A generating system which is not an Intermittent Generating System, such as those fuelled on coal, gas, or distillate
OCGT	Open-cycle gas turbine
PASA	Projected Assessment of System Adequacy
PSR	Power System Reliability
PSS	Power System Security

Term	Definition
RAC	Remaining Available Capacity
RCM	Reserve Capacity Mechanism
RCOQ	Reserve Capacity Obligation Quantity
RCS	RoCoF Control Service
RCS costs	Cost per Trading Interval of procuring the Minimum RoCoF Control Requirement component of RCS
RoCoF	Rate of Change of Frequency
RTM	Real-Time Market
SESSM	Supplementary Essential System Service Mechanism
SOO	Statement of Opportunities report
SSOF	Self-Scheduling Outage Facility
STEM	Short Term Energy Market
SWIS	South West Interconnected System
TSP	Transmission System Plan
WEM	Wholesale Electricity Market
WEM Procedure owners	AEMO, the Coordinator of Energy, the Network Operator, and the ERA
WoSP	Whole of System Plan