



WEM Reform: Wholesale Electricity Market Design Summary

May 2021

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 document provides a high-level summary of the design of the WEM.

This publication has been prepared by AEMO using information available at 1 March 2021. Information made available after this date may have been included in this publication where practical.

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VERSION CONTROL

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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). It describes the various components of the market, their purposes and objectives, and how they interact with each other.

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 market¹.

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 2021

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 the peak 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 managed variations between day-ahead market outcomes and real-time demand and provided all Ancillary Services at administered prices (though there were a small number of bilateral contracts between the system operator and other providers).

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

- The competitive A gross pool Balancing Market operating every half-hour to schedule supply from all generators in the SWIS (with the incumbent state-owned generator 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 the incumbent state-owned generator. Other Ancillary Services were still provided by the incumbent state-owned generator or through bilateral contracts with the system operator.

¹ A copy of the most recent version of the consolidated unofficial Market Rules is available on the Rule Change Panel website, at <https://www.erawa.com.au/rule-change-panel/>. 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/>.

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

1.3 A new market design – 2022 and beyond²

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 no longer always occurring in the late afternoon. 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, displacing lower-priced wind output at significant cost to customers, and
 - Significant medium to long-term network investment.
- 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.

The WA 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)³, 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 system security. 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 regulation and WEM Rules underpinning the maintenance of power system security and reliability was no longer fit for purpose. Changes to power system security and reliability standards and planning processes, as well as changes to the procurement and type of ESS provided to the

² 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>.

³ Historically known as Ancillary Services, with the name change reflecting that such services are increasingly essential to energy supply rather than ancillary.

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 will feature:

- 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 power system security and reliability 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 manage on the day differences between contractual positions and physical outcomes in a way that respects power system constraints and ESS requirements, including facility-level dispatch of Synergy facilities.
- A Supplementary Essential System Service Procurement 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.

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 power system security and reliability issues, including outage planning.
- Chapter 7 describes the RCM.
- Chapter 8 covers the RTM for energy and ESS.
- Chapter 9 describes the Short Term Energy Market (STEM).
- Chapter 10 describes the SESSM.
- Chapter 11 describes the settlement process, 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 purely providing energy.

2. A brief overview of the market

2.1 The market entities

The market comprises the following entities.

- The Coordinator of Energy (Coordinator) and supporting unit Energy Policy WA is a government body reporting to the Minister for Energy. It is responsible for the development of the WEM, including overseeing and administering changes to WEM Rules. At least every five years, it publishes the Whole of System Plan 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 SWIS. It operates the various energy, capacity and ESS mechanisms, conducts short- and medium-term system planning (including outage planning), and dispatches the power system in accordance with the WEM Rules. It also forecasts long-term generation 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 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 ESS, or providing 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 participant to purchase energy in the WEM.
- The Economic Regulation Authority (ERA) is the independent regulator responsible for oversight of the WEM. It monitors market performance and enforces the compliance of Rule Participants with the WEM Rules. It periodically reviews 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), requiring a different treatment of the load of these customers in settlement.

Market Participants, Network Operators, and AEMO are Rule Participants. Becoming a Rule Participant requires an entity to comply with the WEM Rules. Rule Participants that trade in the Reserve Capacity or energy markets are automatically Market Participants. Appendix A2 provides more information on the different functions of these and other entities.

2.2 The trading mechanisms

The market supports the following trading mechanisms:

- **Reserve Capacity Mechanism** – the primary role of the RCM is to ensure capacity is available to meet system demand and maintain ESS requirements during the summer peak load event. 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 future. If there are insufficient Capacity Credits to meet requirements, AEMO can procure Supplementary Capacity via direct contracts.

- Eligible suppliers are issued Capacity Credits for their facilities and must make that capacity available to the market from 1 October to 30 September in the final year of the three-year cycle. Suppliers are paid for their Capacity Credits at an administered Reserve Capacity Price (RCP), and pay capacity refunds if they fail to make capacity available.
- If AEMO determines that normal RCM processes will not ensure enough capacity to meet the Reserve Capacity Requirement, 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. 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 Individual Reserve Capacity Requirements (IRCR).
- **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.
- **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).
 - 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.
- **The Real-Time Market** – the RTM is a gross pool dispatch mechanism. All Registered Facilities must participate and comply with the resulting Dispatch Instructions.
 - 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 way to dispatch Facilities in each five-minute Dispatch Interval to meet demand while respecting network limits and maintaining power system security, and issues 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 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. Market Participants receive (pay) this Reference Trading Price for any quantity above (below) their NCP. Market Participants may be eligible for Energy Uplift Payments where there is network congestion between their Facility's location and the Reference Node. Participants providing Frequency Co-optimised Essential System Services (FCESS) are paid based on the Market Clearing Price for those services in each Dispatch Interval.
- **The Supplementary Essential System Services Mechanism** – the SESSM is a mechanism for procuring ESS capability over a longer timeframe than provided 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.

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.

A subset of ESS is procured in the RTM from accredited Facilities. These are the FCESS: Regulation, Contingency Reserve, 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 via the SESSM, and the ERA can do the same where FCESS Market outcomes are inconsistent with competitive provision.

Other ESS (including System Restart Services and locational services used to substitute for network upgrades) are procured through contestable contracts from capable providers.

2.4 Facility classes and characteristics

The information in this section is provisional and has been drafted with consideration to Taskforce decisions published on the Energy Policy Western Australia (EPWA) website. This section will be revised in a future release as more information becomes available.

Entities are either mandated to register or can optionally register themselves as Market Participants and their Facilities in various Facility Classes in the WEM to provide services such as energy, ESS, and Reserve Capacity from the relevant Registered Facility.

A Facility is either:

- A transmission system or a distribution system, which is registered in the Network Facility Class (with the Network owner having to register in the Network Operator Rule Participant class), or
- A combination of technology types behind a network connection point. For example:
 - A combined-cycle gas turbine (CCGT) at a network connection point.
 - A hybrid system comprising an Intermittent Generating System and an Electric Storage Resource at a network connection point.
 - One or more Loads at a network connection point.
- A Small Aggregation comprising distribution connected technologies at a single Electrical Location⁴.

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.

⁴ 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.

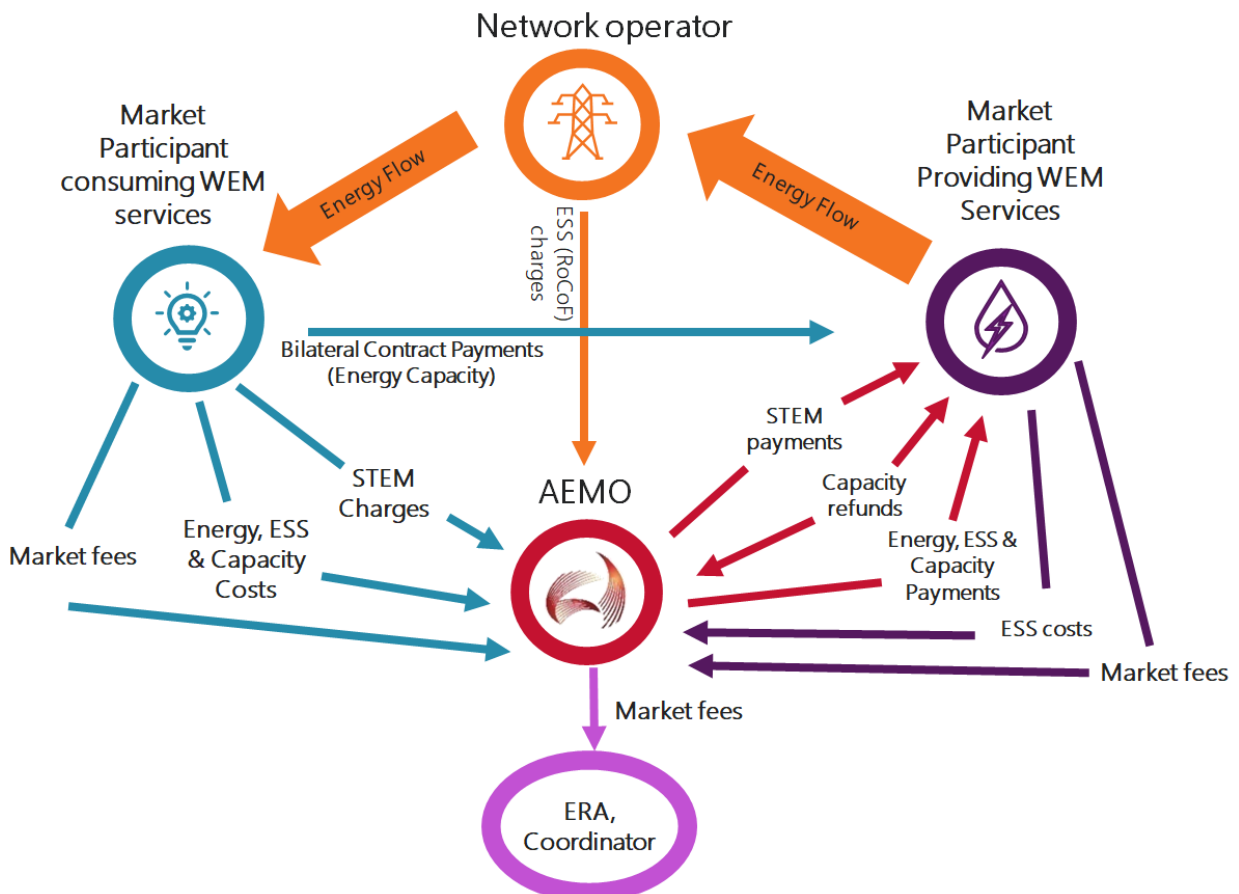
- A Non-Scheduled Facility comprises an Energy Producing System with a System Size less than 10 MW that is not required to comply with Dispatch Targets or Dispatch Caps but must respond to Directions during system emergencies.
- An Interruptible Load comprises one or more Non-Dispatchable Loads that can provide Contingency Reserve Raise ESS by interrupting their supply from the network in when they detect that system frequency has deviated from the target band.
 - A Non-Dispatchable Load is an unregistered Facility comprising one or more uncontrollable loads (for example, commercial and industrial loads or households).
 - 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.

2.5 Market settlement

Market Participants settle WEM transactions with AEMO. Market Participants buy energy or capacity from, or sell energy or capacity to, AEMO. 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.

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.

Figure 1 Settlement cash flows



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 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) are recovered on the basis of energy volumes.

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, such as suspension from the market, on a party in default.

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 resolved quickly then the outstanding amount will be recovered by a default levy. Default is expected to be 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

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 Energy Policy WA (EPWA), the state government energy policy body. EPWA and the Coordinator report to the Minister for Energy.

The Coordinator's functions under the WEM Rules are:

- Maintaining and developing the WEM Rules, including developing amendments, administering the rule change and procedure change processes, and making decisions on Rule Change Proposals.
- Maintaining and developing Market Procedures relating to rule and procedure administration.
- Publishing a Whole of System Plan for the SWIS every five years, including modelling various scenarios over a 20-year horizon.
- Providing independent oversight for certain market processes by conducting periodic reviews of:
 - General market effectiveness.
 - 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 Minister 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 for existing facilities.

3.3 Australian Energy Market Operator

AEMO is responsible for operating western, eastern, and south-eastern energy markets and systems, including the WEM and the Western Australia Gas Bulletin Board. AEMO is the market operator for the WEM and the system operator for the SWIS.

AEMO's WEM functions are:

- 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 Whole of System Plan.
 - Advising and consulting with Network Operators in respect of System Operation Functions as contemplated under the technical rules for their networks.
 - Maintaining and developing WEM Procedures relating to market operation, market administration and system operation.
- 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.
 - Operating the STEM.
 - Operating the RTM and issuing Dispatch Instructions to Market Participants.
 - Procuring, scheduling, and dispatching sufficient ESS to meet the ESS Standards.
 - Coordinating and, where applicable, conducting tests of equipment (Commissioning Tests and Reserve Capacity Tests).
 - Conducting market settlement.
- 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 participant compliance with some rule obligations.
 - Maintaining a register of DER.

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. The AEMO Board has a majority of independent directors, who are accountable to the members. 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). 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. It regulates competition and monopoly infrastructure in the electricity, gas, water, and rail sectors. Its primary WEM function is to monitor compliance of Rule Participants with the WEM Rules, investigate potential breaches, and initiate enforcement action where appropriate. The ERA can impose a variety of penalties including warnings, infringement notices, financial penalties, and, in the most serious situations, bringing proceedings before the Electricity Review Board.

The ERA's other WEM functions are:

- Maintaining and developing WEM Procedures relating to market monitoring and compliance.
- Approving efficient costs for AEMO's operation and the resulting Market Fees.
- Determining the Benchmark Reserve Capacity Price (BRCP) and the market price limits.
- Triggering the SESSM in case of inefficient market operation.
- 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.

3.5 The Electricity Review Board

The Electricity Review Board is the primary appeals body for the WEM, having the functions of:

- Considering cases referred to it by the ERA for more serious breaches of the WEM Rules, and imposing penalties, including financial penalties, suspension, and deregistration.
- Hearing appeals against the ERA's decisions pertaining to WEM rule breaches.
- Hearing appeals against Reviewable Decisions.
- At the behest of a Rule Participant, conducting a Procedural Review as to whether the Coordinator, the ERA, AEMO, or a Network Operator has correctly followed the rules pertaining to rule changes and procedure changes, and where appropriate over-turning rule change and procedure change decisions if the outlined process has not been followed.

3.6 The Market Advisory Committee

The Market Advisory Committee is an industry group made up of industry representatives and convened by the Coordinator. It advises the Coordinator on the development and evolution of the market and the WEM

Rules, and advises the Coordinator, the ERA, AEMO, and Network Operators on WEM Rule and Procedure changes and general market operation issues.

The Market Advisory Committee consists of an independent chair appointed by the Minister, and 13 to 17 other members appointed by the Coordinator (in consultation with the independent chair) from representatives nominated by:

- Market Participants (seven to nine members, including one representing Synergy).
- Contestable Customers (one or two members).
- AEMO (two members).
- Network Operators (one or two members, including one representing Western Power).
- The Minister (at least two members independent of government representing small consumers).

The Minister and the ERA may both appoint representatives to attend meetings of the Market Advisory Committee as observers. Where an issue to be addressed by the Market Advisory Committee is highly technical or specialised, the Market Advisory Committee may decide to form a working group of industry representatives to investigate and report back on the issue.

3.7 Network Operators

Some Network Operator functions are also covered under the WEM Rules. Western Power is currently the only registered Network Operator in the SWIS. Network Operator functions are:

- 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 preparation of the Whole of System Plan.
- Managing the connection of new Facilities to its transmission network, including:
 - Reviewing, negotiating, approving, and maintaining a register of Generator Performance Standards for connected Facilities.
 - Issuing and revoking Approval to Generate and Interim Approval to Generate Notifications for newly connected Facilities.
- 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

The Coordinator is responsible for maintaining and developing the WEM Rules. When deciding to confer rule-making functions on the Coordinator, the WA government acknowledged that, as an entity supported by a government policy body, there are potential perceived conflicts of interest in the Coordinator having administrative control and decision making powers of rules which may affect state-owned Rule Participants such as Synergy and Western Power, noting that⁵:

While the governance reforms address many present challenges, perceptions around the potential for conflict of interest have been raised in several stakeholder submissions.

To manage such conflicts, 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 partially follow their advice), it must justify the reasons in the Final Rule Change Report.

Rule Participants may appeal decisions made by the Coordinator in amending the rules to the Electricity Review Board on procedural grounds. This means the Electricity Review Board can only overturn a rule change if the Coordinator has not followed the correct rule change process.

Every three years, the Coordinator must arrange an independent review of the effectiveness of the rule 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

There are no restrictions on who can propose a rule change. Proponents must submit Rule Change Proposals to the Coordinator in a prescribed format including the reasons why they think the rule change is desirable.

Upon receiving a Rule Change Proposal, the Coordinator decides whether the proposal should be progressed. If the Coordinator deems the Rule Change Proposal merits further investigation, then it commences the rule change process, in which it assesses the requested changes against the WEM Objectives and practical considerations. The only appeal option is to the Electricity Review Board, and then only in the case of procedural breaches by the Coordinator; that is, it is not possible to dispute the merit of the rule change.

A Rule Change Proposal may include explicit proposed wording for changes to specific rule clauses, or could be a more general identification of an issue with a general proposal as to how it could be addressed. In processing a Rule Change Proposal, the Coordinator develops amendments to the WEM Rules to implement the proposed changes and consults with Rule Participants on the need and form of the rule amendment.

There is a Fast Track Rule Change process for urgent rule changes, and rule changes to correct manifest errors or to address minor issues. Under the fast track process the Coordinator undertakes a single round of consultation. This process takes approximately five weeks from submission of the Rule Change Proposal.

⁵ See https://www.wa.gov.au/sites/default/files/2021-01/Energy%20Sector%20Governance-%20Public%20Consultation%20Response%20Paper_final.pdf.

The Standard Rule Change process includes two rounds of formal consultation, with the second round allowing consultation on a draft report published by the Coordinator prior to the finalisation of the report and will usually take around 19 weeks from submission of the Rule Change Proposal.

The Coordinator makes a final decision on a Rule Change Proposal and if the rule change relates to a Protected Provision⁶ will seek the Minister's approval. The decision of the Minister is not subject to appeal. The Coordinator's decision and its reasons are published on the market website, together with a time and date when accepted rule changes will come into force.

4.2 WEM Procedures

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 Generator Performance Standards, Limit Advice, and Determination of Loss Factors.
- The ERA develops and changes the WEM Procedure relating to 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 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 Monitoring and enforcement of the WEM Rules

The ERA monitors the compliance of Rule Participants with the WEM Rules and WEM Procedures. AEMO supports the ERA in its monitoring role.

AEMO monitors the compliance of Market Participants with their dispatch compliance obligations and reports any breaches to the ERA.

Rule Participants must self-report breaches of the WEM Rules and WEM Procedures to the ERA, and can allege breaches against other Rule Participants (including AEMO and the Network Operator) to the ERA.

When the ERA becomes aware of a rule breach by a Rule Participant, it logs the breach, notifies and consults with the breaching Rule Participant, and investigates whether a breach has occurred. Following investigation, the ERA may then consider whether any enforcement action should be taken. Enforcement can include:

⁶ Examples of Protected Provisions includes 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 Reserve Capacity and certain Reserve Capacity Security provisions, and some aspects of settlement such as certain default provisions.

- Issuing a financial penalty in the form of an infringement or a civil penalty. The classes of financial penalties under the Regulations for breaches of the Market Rules are:
 - 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 involving system security or financial matters.
 - Infringements which are a prescribed amount as a proportion of a civil penalty.
- Bringing proceedings before the Electricity Review Board for an order under the WEM Regulations for very serious offences which may require temporary or permanent Rule Participant de-registration or Facility disconnections.

4.4 Reviewable Decisions and disputes

In the WEM Rules, some 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 Generator Performance Standards 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.

4.5 Budgets and fees

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 is regulated by the ERA. The Allowable Revenue represents a medium-term view of AEMO's operational costs. The ERA periodically determines the Allowable Revenue of AEMO. Every year AEMO submits a budget to the ERA, which must be consistent with the Allowable Revenue determination.

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 reassessment of Certified Reserve Capacity (CRC).

4.6 Price limits

4.6.1 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).

4.6.2 Maximum STEM Price and Alternative Maximum STEM Price

Each year, the ERA determines maximum price limits for the STEM and RTM under section 6.20 of the WEM Rules. These function as a cap on prices when there is a shortage and are also used to restrict market participant offer prices.

Two price caps are defined, based on the ERA's estimate of the short run marginal cost of the most expensive facility in the generation fleet:

- The Maximum STEM Price assumes the facility will be fuelled by gas.
- The Alternative Maximum STEM Price assumes the facility will be fuelled by liquid fuel.

Participants may only offer into the STEM at the Alternative Maximum STEM Price if their facility is actually using liquid fuel.

In the RTM, energy offers can be up to the Energy Offer Price Ceiling, which is equal to the Alternative Maximum STEM Price.

4.6.3 Minimum STEM Price

Each year, the ERA determines minimum price limits for the STEM and RTM under section 6.20 of the WEM Rules. The Minimum STEM Price provides a floor for market prices in times of extreme system conditions (when Market Participants would prefer to pay to inject energy rather than shut down a Facility) and is also used to restrict market participant offer prices.

The Minimum STEM Price is set based on the principles that it should:

- Be low enough that the market clears above it in most 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.

STEM Offers must be above the Minimum STEM Price. RTM Offers must be above the Energy Offer Price Floor, which equals the Minimum STEM Price.

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 Western Power 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 agree a Generator Performance Standard (GPS) that will apply to Facility operation^{7,8}. 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 power system security 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 Generator Performance Standards 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 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 Generator Performance Standards and must monitor its own compliance according to an AEMO-approved Generator Monitoring Plan (which must be based on principles

⁷ The technical requirements of distribution-connected Facilities are governed by the Technical Rules, which, unlike the GPS, are not a negotiated framework.

⁸ Note that the connection process is governed by the Electricity Networks Access Code, while the GPS requirements are governed by the WEM Rules.

set out in AEMO's Generator Performance Standards WEM Procedure). On self-detecting non-compliance, the participant must notify AEMO immediately, and propose a Rectification Plan. Where a participant self-notifies and corrects the issue as per their Rectification Plan, they are not subject to non-compliance penalties from the ERA⁹.

5.2 Rule Participant and Facility registration

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.

5.2.1 Rule Participant classes

WEM Rules confer obligations on Rule Participants who fall into three classes:

- Network Operator – Rule Participant registration is enforced on Network Operators only if AEMO requires information about the relevant Network to ensure Power System Security and Reliability.
- 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. Rule Participant registration on these groups is enforced based on the size of their Energy Producing Systems (see Section 5.2.4). Where Rule Participant registration is not enforced, entities can register optionally.
 - Entities that serve end-use customers (retailers), and purchase WEM services to serve their customers – Rule Participant registration is enforced on this group.
- AEMO.

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

5.2.2 Definition of a Facility

A Facility is either:

- A transmission system or a distribution system, which is registered in the Network Facility Class (with the Network owner having to register in the Network Operator Rule Participant class), or
- A combination of technology types at a network connection point. For example:
 - An Energy Producing System behind a network connection point. An Energy Producing System is one or more energy producing technology types; a Facility containing an Energy Producing System might be (but is not limited to):
 - A Non-Intermittent Generating System like a CCGT at a network connection point.
 - An Intermittent Generating System like wind turbines and/or solar systems at a network connection point.
 - A hybrid system comprising an Intermittent Generating System and an Electric Storage Resource at a network connection point.
 - One or more Loads at a network connection point. Loads can be optionally registered if they are fully controllable or curtailable (see Section 5.2.4).

⁹ The Network Operator can exempt participant from compliance with Generator Performance Standards if costs would outweigh the benefits. However, the exempted Facility would still be subject to the requirements set out in the Technical Rules.

- A Small Aggregation comprising distribution connected technologies at a single Electrical Location¹⁰.

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 the next section).

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 (DSP).

The section below 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 determines that it requires information from the Network Operator's Network to ensure Power System Security and Power System Reliability; and if Registered Facilities are directly connected to that Network. 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 the System Size of a Facility comprising an Energy Producing System that triggers the mandatory requirement to register.

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

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 minimum of its DSOC and total MW output capability of all energy producing technologies comprising the Facility, and
- The minimum of its Contracted Maximum Demand and the total consumption capability of all Electric Storage Resources comprising the Facility.

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

¹⁰ 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.

Figure 2 System Size of Facility comprising wind and battery hybrid

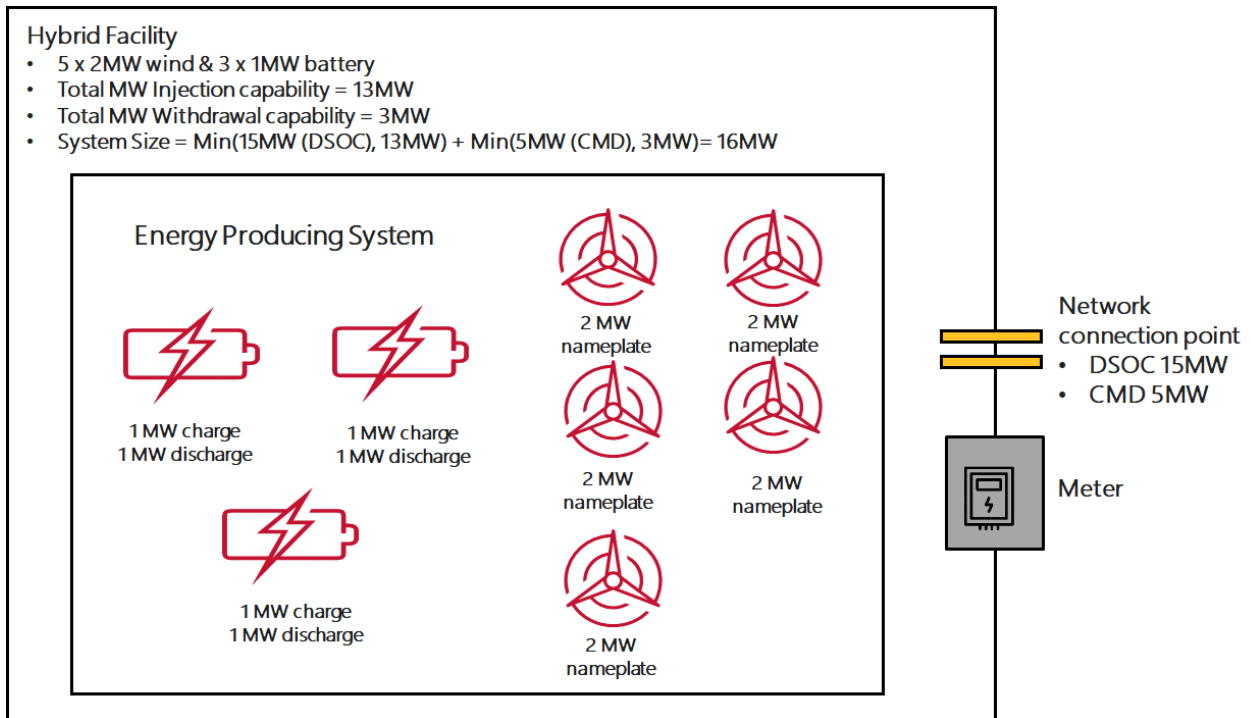


Table 1 summarises the registration requirements for Market Participants and their Facilities comprising Energy Producing Systems.

Table 1 Rule Participant and Facility registration requirements

Facility System Size	Registration requirements
10 MW or greater	Unregistered participant must register in the Market Participant class, and must register its Facility.
5 MW or greater but less than 10 MW	Unregistered participant must apply to AEMO for exemption from Rule Participant and Facility registration. If exemption is not granted, the participant must register in the Market Participant class and register its Facility. AEMO can revoke exemption if participant's Facility must be registered for power system security and reliability purposes. Participant may optionally register as a Market Participant and register its Facility if it wishes to provide WEM services.
Less than 5 MW	Unregistered participant has standing exemption from AEMO from Rule Participant and Facility registration. AEMO can revoke exemption if participant's Facility must be registered for power system security and reliability purposes. Participant 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	<p>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).</p> <p>A Facility containing an Energy Producing System which is deemed to be fully controllable by AEMO must be registered in the Scheduled Facility class.</p>
Semi-Scheduled Facility	<p>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).</p>
Non-Scheduled Facility	<p>Not required to comply with Dispatch Targets or Dispatch Caps but must respond to Directions during system emergencies.</p> <p>Only Facilities with a System Size below 10 MW can be registered in this category.</p> <p>Under certain circumstances (relating to power system security and reliability), AEMO may enforce registration in the Scheduled Facility or Semi-Scheduled Facility Classes or sub-10 MW Facilities which could otherwise have registered as a Non-Scheduled Facility.</p>

Facilities containing Loads

A Facility may also comprise one or more Loads, which are electricity consuming resources other than an Electric Storage Resource. 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	<p>A Facility containing one or more Scheduled Loads can register in the Scheduled Facility Class. A Scheduled Load is a Load that has been certified by AEMO as being fully controllable and able to respond to Dispatch Instructions by increasing and decreasing its Withdrawal.</p>
Interruptible Load	<p>Facility comprising one or more Non-Dispatchable Loads that can be interrupted in response to a frequency signal to provide Contingency Reserve Raise ESS.</p> <p>The Facility must be registered in the Interruptible Load Facility Class.</p> <p>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-Dispatchable Load with an Interruptible Load provided they have an agreement with the party operating or controlling the Load.</p> <p>Interruptible Loads are compensated solely via ESS payments, which are paid to the Market Participant who has registered the Interruptible Load.</p> <p>Energy consumed by the associated Non-Dispatchable Loads is settled by the participant for that Non-Dispatchable Load.</p>

Facility class	Description
Demand side programme	<p>Facility comprising one or more Non-Dispatchable Loads that can be curtailed on request by AEMO.</p> <p>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.</p> <p>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.</p> <p>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.</p> <p>Energy consumed by the associated Non-Dispatchable Loads is settled by the participant for that Non-Dispatchable Load.</p>

Intermittent Loads

An Intermittent Load is a load that is normally fully supplied by a generator at the same site as the load without requiring any electricity to be supplied from a Network registered with AEMO. In effect, it is load normally served by embedded generation. An Intermittent Load only requires electricity from the network when its embedded generator is not fully operational, and consequently its exposure to funding Reserve Capacity is reduced. A Non-Dispatchable Load can simultaneously be an Intermittent Load or be part of an Intermittent Load if it satisfies the required registration conditions.

There are currently six Intermittent Loads participating in the WEM. These Loads have been grandfathered under the new market arrangements. No new Intermittent Loads will be allowed to enter the WEM. Registered generation systems serving the grandfathered Intermittent Loads will be transitioned to the relevant new Facility Class.

Participants wishing to register Facilities which comprise an Energy Producing System and a co-located Load at a single network connection point can still participate in the WEM; however, they would not be able to avail themselves to the specialised funding arrangements for Reserve Capacity, or the Facility registration exemption requirements that existing Intermittent Loads are subject to.

5.3 Facility aggregation

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.

Participants may wish 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 power system security and reliability.
- The participant can provide AEMO with Standing Data for individual Facilities, and for the aggregation as required.

5.4 Registration process

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.

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

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 an externally administered body corporate, 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 relevant WEM Procedure, including timelines and information requirements.

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.

5.4.3 Standing Data

Rule Participants must submit "Standing Data" to AEMO to complete the registration process.

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, or if the participant becomes aware of an error.

5.5 Facility commissioning

AEMO requires a Facility to undergo Commissioning Tests to (but not limited to):

- 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 Generator Performance Standards.
- Demonstrate ability to be accredited under the ESS accreditation process (see below).

Facilities undergoing commissioning must have their Commissioning Test Plan approved by AEMO, and must comply with AEMO's Dispatch instructions when carrying out the Commissioning Test.

5.6 Facility accreditation for ESS

Before a Facility can participate in the RTM for a FCESS, AEMO must confirm its 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. Accreditation can be reassessed:

- On a Participant's request, where at least 12 months has elapsed since the previous accreditation; and
- At AEMO's discretion, where less than 12 months has elapsed since the previous accreditation, and there is reason to believe accredited parameters no longer accurately reflect facility capability.

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

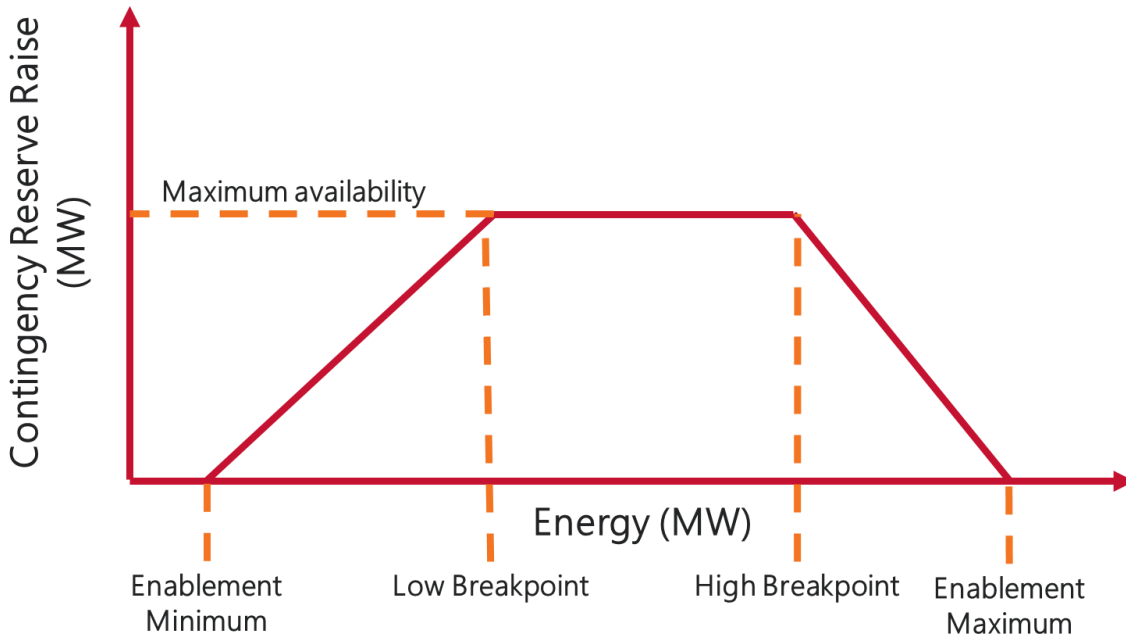
5.6.1 FCESS trapezium

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

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



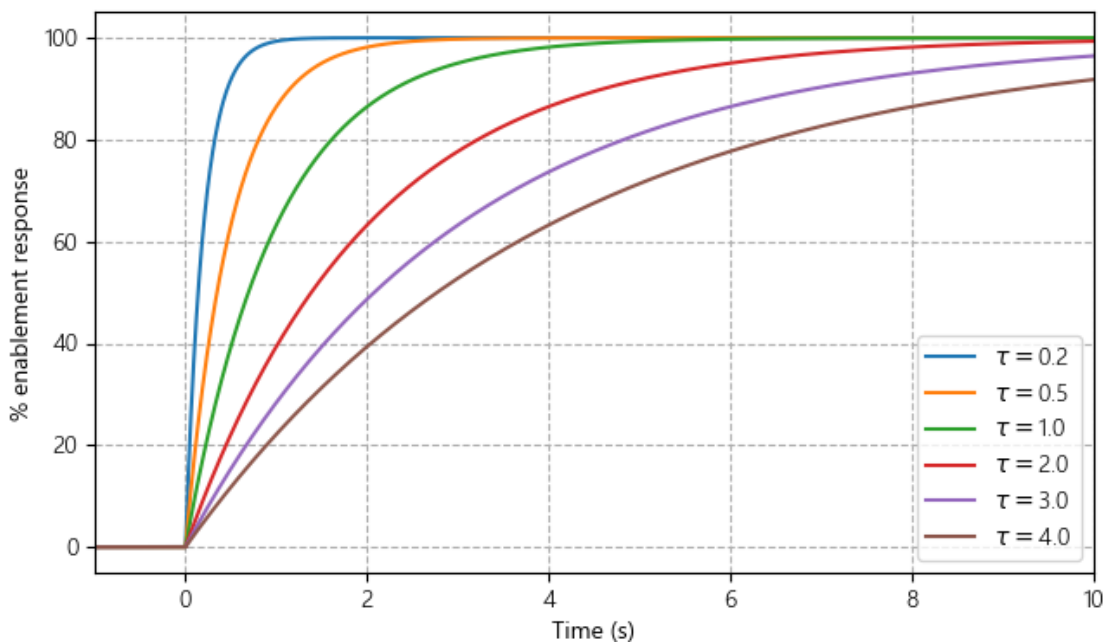
5.6.2 Speed factors

For Facilities providing Contingency Reserve, accreditation test results will be used to determine a '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 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 Speed Factor.

Equation 1: Facility Speed Factor curve

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

Figure 4 Example translation of response curves to speed factors



A Facility which 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. Market Participants must post Credit Support with AEMO which must at least equal their Credit Limit; the latter is the maximum net dollar amount that the Market Participant is likely to owe AEMO within the maximum 35-day period between being the start of a Trading Week and the date on which 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-payment¹¹.

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 (covering settled and unsettled transactions). 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 can address by posting additional Credit Support. Failure by a Market Participant to address a Margin Call may lead to the participant being declared to be in default.

5.8 Facility and Rule Participant de-registration

5.8.1 Facility de-registration

Market Participants may de-register Facilities that are being retired or transferred to another Market Participant. A Facility for which a Participant holding 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. Market 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 for more than 90 days.

¹¹ 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.

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 Power System Reliability in the SWIS is 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 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 when and what discretionary actions AEMO 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 security and reliability issues.
- Mandatory outage reporting and approval processes, to ensure visibility of participant 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. They apply to the SWIS, and to embedded networks 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.

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

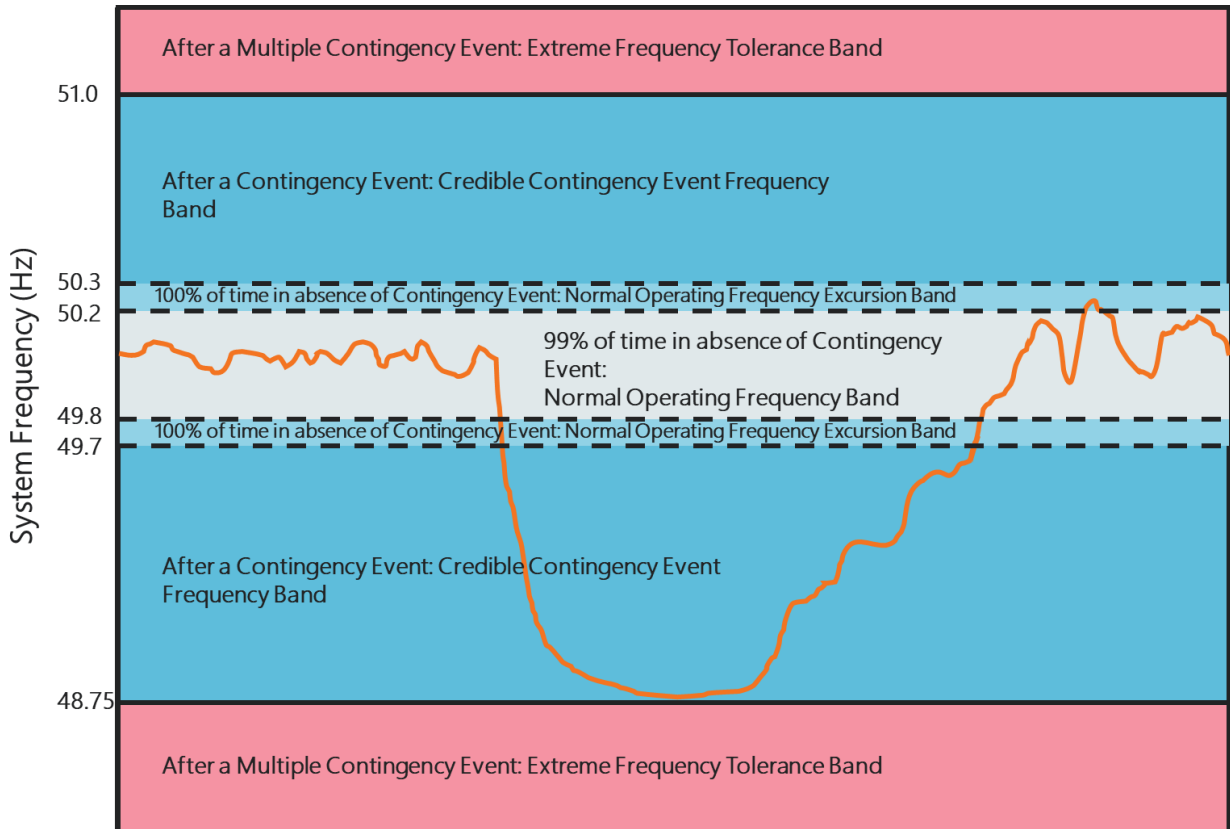
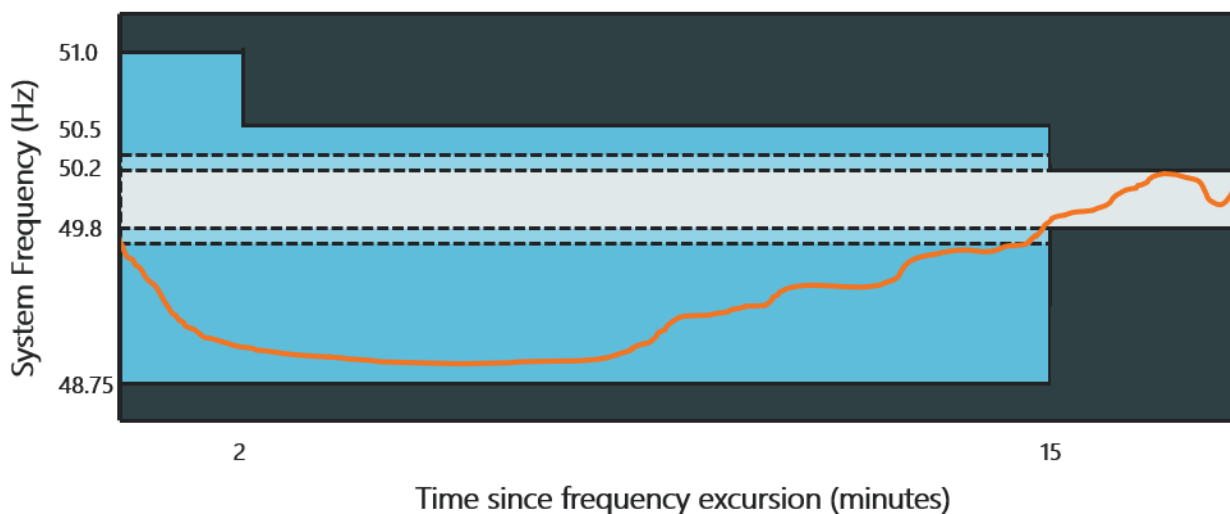


Figure 6 Stabilisation and recovery times following a single Credible Contingency Event



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.

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.

The operating states are the basis of the Power System Security Principles and Power System Reliability 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):

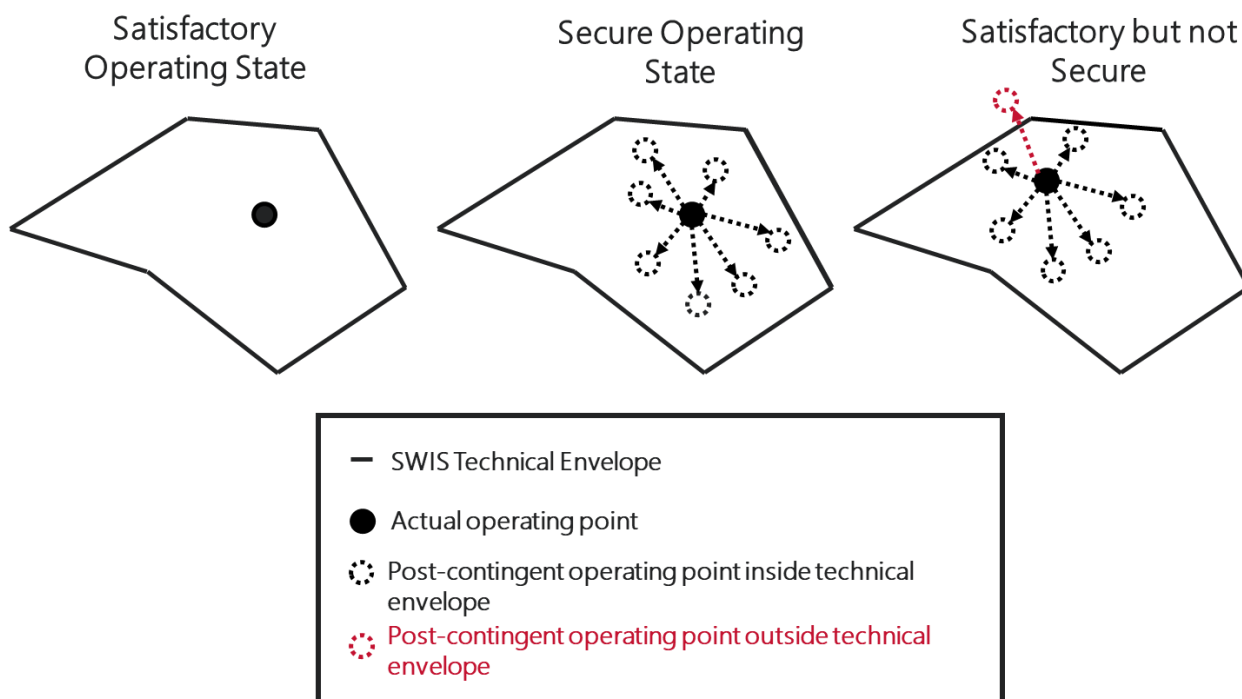
- A **Reliable Operating State** applies when the power system can meet expected load and there are no constraints requiring load shedding; that is, no manual load shedding has occurred or is projected to occur. AEMO must operate the SWIS to stay in this state as far as practicable. When the SWIS is 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 will return to a Satisfactory Operating State after a Credible Contingency Event without further AEMO intervention, or within 30 minutes with AEMO intervention; that is, if 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: the system is operating with "n-1" security.
- 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 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 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.

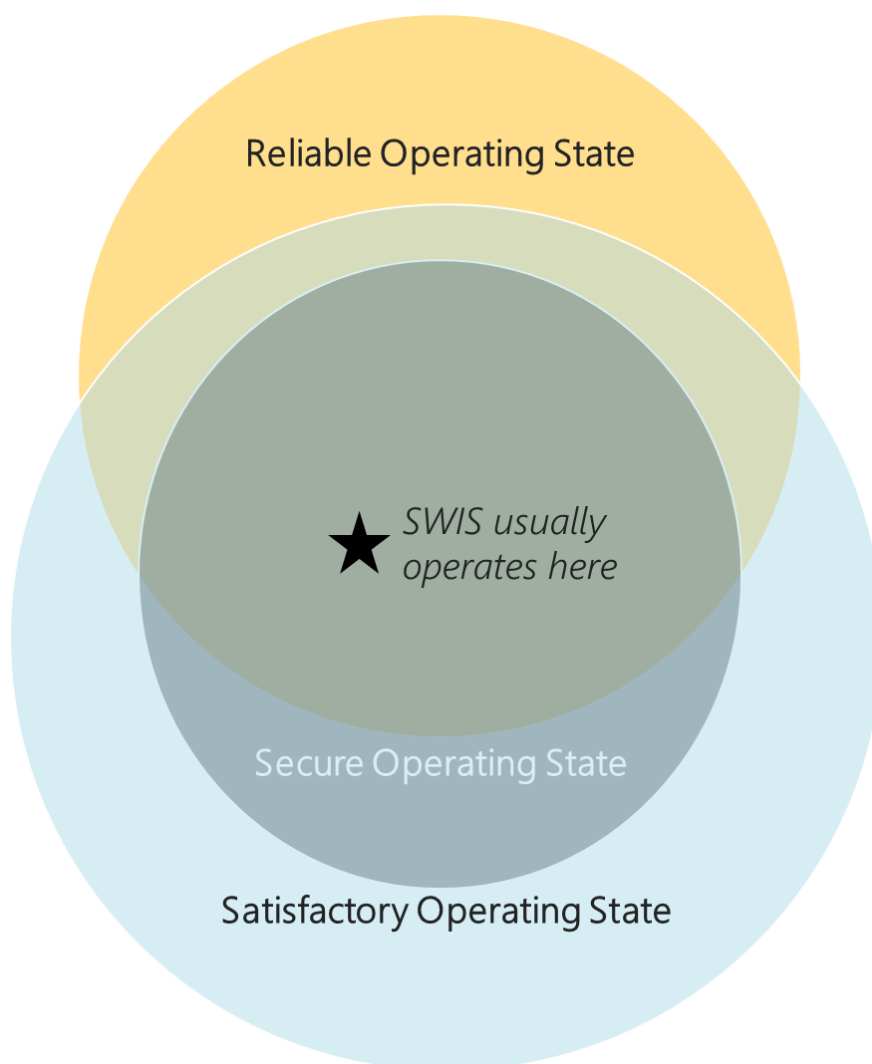
Figure 7 Satisfactory and Secure Operating States



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 it is necessary to restore or maintain Reliable, Satisfactory, or Secure operation, AEMO may intervene in market processes by rejecting or recalling Facility outages, directing Facilities to adjust output in accordance with their Generator Performance Standards, or directing a Network Operator to operate or disconnect network equipment.

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 8.9) if the system 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.

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 “Essential System Services” are becoming more and more important as the energy transition continues and conditions on the power system become more volatile.

There are two categories of ESS:

- FCESS are procured via the RTM.

- ESS not procured via the RTM are the Non Co-optimised Essential System Services (NCESS). At present, System Restart Service is the only defined NCESS. In future, other NCESS may be defined to provide services in specific network locations, or to describe other ways Facilities can provide support for power system operations.

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 ESS are defined in the market rules:

- FCESS:
 - **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** 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.
- NCESS:
 - **System Restart Service** assists in re-energising the SWIS in the event of a system-wide blackout or major supply disruption. It is provided by Facilities which can start without needing energy from the network.

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, as well as decreasing RoCoF, increasing the amount of inertia on the SWIS has an additional benefit in that it acts to reduce the quantity of Contingency Reserve Raise service required to maintain minimum frequency levels. 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.

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 11.4.2 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 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.
 - An additional portion is only procured if it reduces the overall cost of supply (by reducing the required quantity of Contingency Reserve Raise) and 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.

Rule Participants do not have to pay for the 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 11.4.3 for a detailed discussion of how the first portion is cost-recovered).

- System Restart costs are recovered from Registered Facilities and Non-Dispatchable Loads in proportion to their metered consumption in the relevant Trading Interval.

6.4 Projected Assessment of System Adequacy

As part of ensuring power system security and reliability, 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 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 (LRCs), and considering the 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

Good visibility of future network and generator 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.

Market Participants are required to tell AEMO when their Registered Facilities are unavailable for dispatch, by submitting planned 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:

- AEMO needs this information to accurately forecast expected power system conditions, including reserve margins and appropriate Constraints Sets for use in the Dispatch Algorithm. AEMO 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 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-ratings¹². This list includes Facilities holding Capacity Credits, Facilities that provide ESS, items of network equipment that could limit the output of such Facilities, and any other equipment that could affect the security and reliability of the SWIS. 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.

¹² At <https://aemo.com.au/-/media/files/electricity/wem/data/system-management-reports/equipment-list.pdf>.

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.

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 as long as 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). Where 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 starting the outage, 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.

Market 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 unaffected capability, 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 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. This information helps coordinate network and generator outages. AEMO uses the information provided to construct and publish a consolidated Outage Intention Plan covering all 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 Market Participants' ability 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 the reliability and security of the power system.
- 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 followed 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 power system security 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

Where 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, its 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).

6.6 Network limits and Constraint Equations

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 a key input to constrained optimisation calculations in the 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.

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.

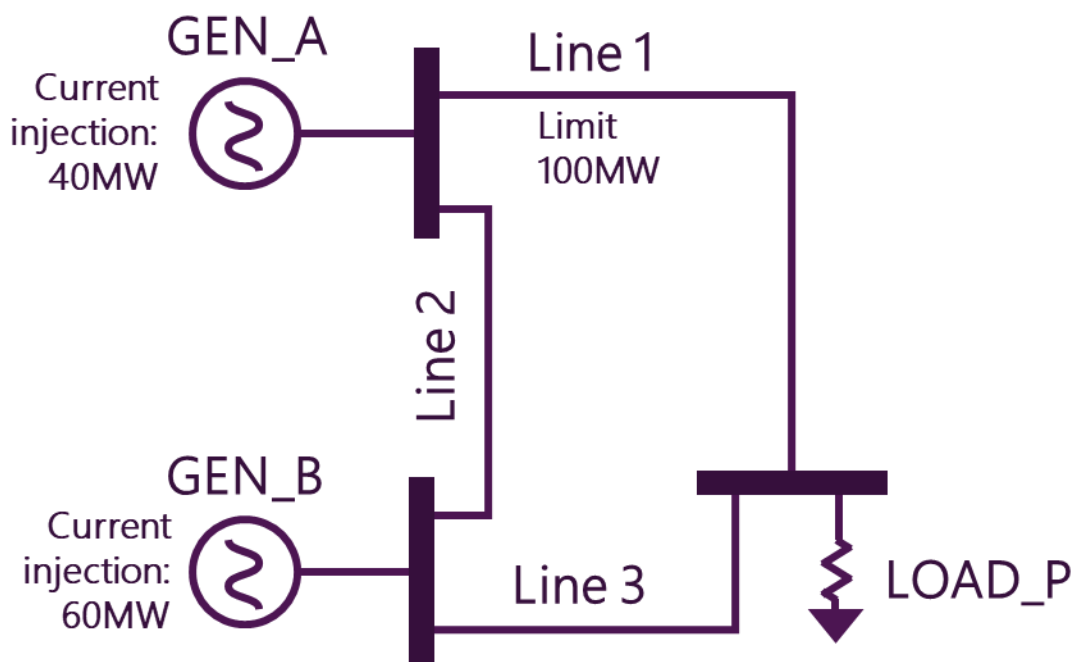
In practice, the topography of the transmission network means equations need to account for multiple facilities which contribute unequally to the flow on a line. A more generic formulation might be Equation 3.

Equation 3: Generic multi-Facility line limit constraint

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

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



For example, 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 – 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 Constraint Library includes thousands of Constraint Equations, potentially containing one equation for each combination of limit, network configuration, and Credible Contingency Event. That is:

- For each different network configuration (which equipment is in service, how that equipment is connected, and what the level of demand is), there will be a set of equations;
- for every equipment limit (thermal and non-thermal) provided by the Network Operator in Limit Advice, with a set of equations that describes 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 Constraint 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

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 library of Constraint Equations, 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 power system security and market costs. Power System Security 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 Western Power 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.

7. The Reserve Capacity Mechanism

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, specifies the Annual Reserve Capacity Requirements, and publishes these 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 Individual Reserve Capacity Requirement (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 Certified Reserve Capacity (CRC) (as determined during certification); and
- Their network access rights as determined by the Network Access Quantity (NAQ) calculated by AEMO.

Market Participants can either procure Capacity Credits bilaterally from Capacity Credit suppliers, or they can purchase them from AEMO.

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.

Figure 10 Reserve Capacity Cycle timeline

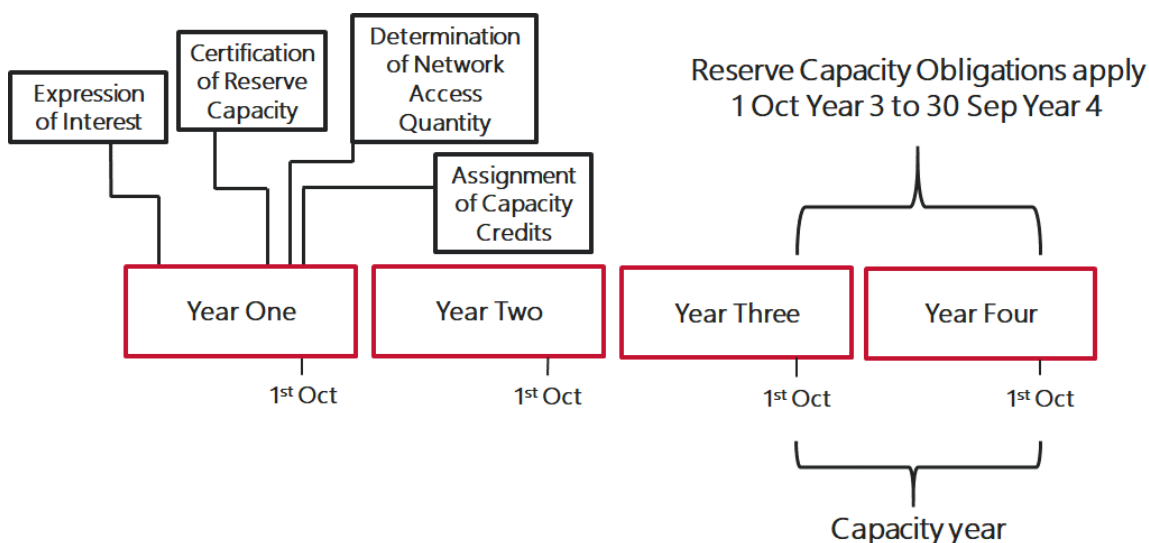
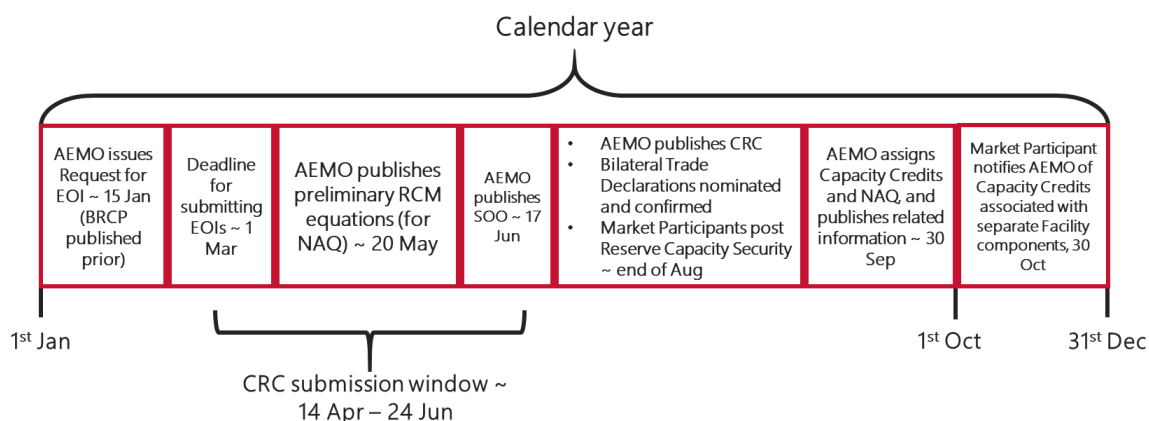


Figure 11 Reserve Capacity timeline for Year 1



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.

7.3.1 Expressions of interest for new capacity and retirement notifications

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 Expression of Interest (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 retirement¹³, so AEMO can incorporate the resulting additional network access into the NAQ determination.

¹³ The three-year window can be shortened in extenuating circumstances; for example, where a Market Participant becomes insolvent, suffers a force majeure incident, or has to retire a plant for commercial reasons.

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 Whole of System Plan; however, the ESOO may make use of transmission planning information provided by Network Operators.

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:

- Capacity from generation systems¹⁴ 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 available at all times. 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 power system security and reliability (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 power system security and reliability).

7.4 Capacity allocation

7.4.1 Certified Reserve Capacity

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 Facilities¹⁵, 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:

¹⁴ This includes hybrid Facilities comprising generation systems paired with Electric Storage Resources.

¹⁵ For example, by considering whether access contracts exist, and whether environmental permits have been obtained.

- 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 Resource at a Facility are awarded capacity based on a Linear 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, given their storage (MWh) capability and capacity (MW).
- 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 Intervals¹⁶.

Hybrid Facilities can comprise two or more of the 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. Where conditional certification has been granted, when the Market Participant applies for final certification, if 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 trade bilaterally, 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 traded bilaterally 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

Network congestion may preclude a Facility that has been awarded CRC injecting the full amount of CRC it intends to trade bilaterally during peak Trading Intervals. As such, before assigning Capacity Credits AEMO needs to consider the forecast effects of congestion on a Facility's ability to provide capacity during peak Trading Intervals. AEMO does this by determining a NAQ for each Facility that has been awarded CRC. In doing so, AEMO must consider 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, Western Power provides Limit Advice to AEMO, which AEMO uses to develop RCM Constraint Equations to model the facility dispatch scenarios.

¹⁶ 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).

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.

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 which 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 Access¹⁷ arrangement prior to the 2022 cycle) that 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

¹⁷ 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.

- 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 Reserve Capacity Obligation Quantity (RCOQ). As with CRC, RCOQs vary depending on the Facility's technological characteristics and capabilities.

- The Intermittent Generating System component of a Facility has an RCOQ of zero in all Trading Intervals; this reflects the unpredictability of their output.
- 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). At other times, the RCOQ of the storage component is zero.
- The Non-Intermittent Generating System component of a Facility has an RCOQ equal to the quantity of Capacity Credits assigned in all Trading Intervals.
- 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. as a result of a Forced Outage. 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 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.

7.5 Reserve Capacity Security

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 Level¹⁸ 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 Reserve Capacity.

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).

¹⁸ 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.

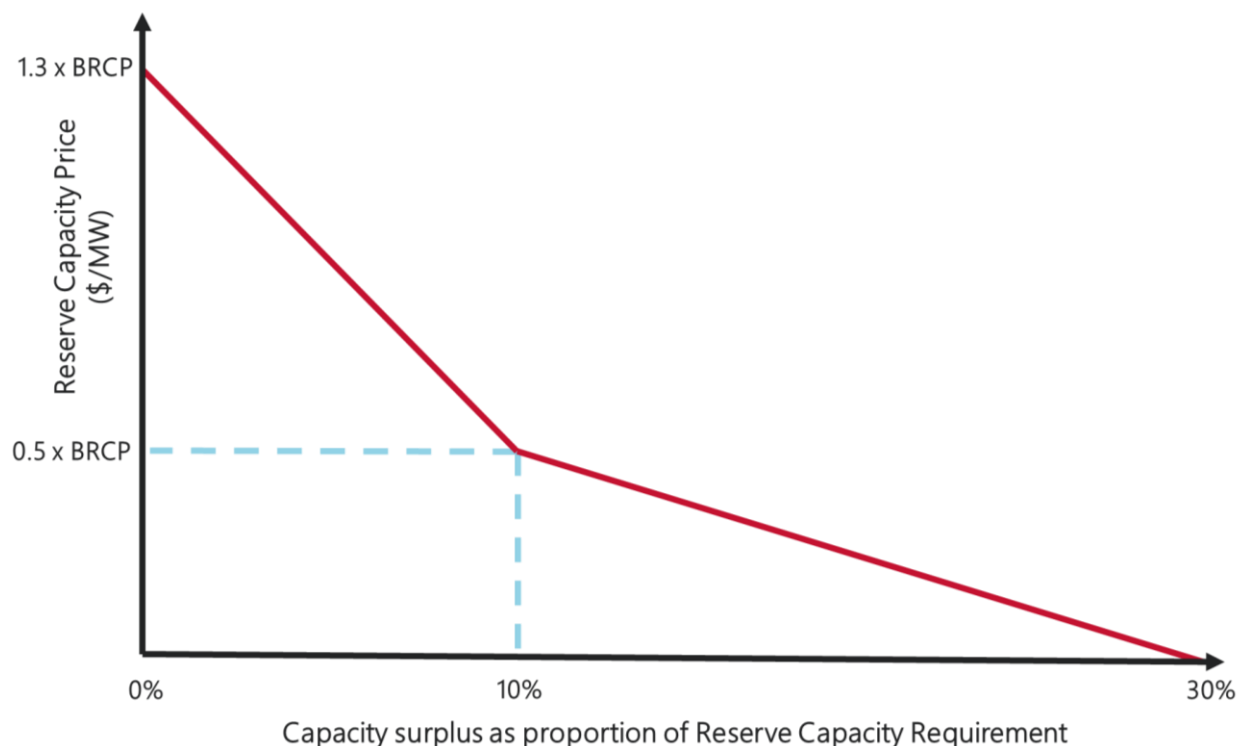
7.6 Reserve Capacity Prices

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.

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%¹⁹, 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



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.

¹⁹ Deemed to be the level of surplus at which no capacity should enter the market (from an economic perspective).

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 Reserve Capacity

If AEMO considers at any time during the six months prior to the Capacity Year that there will be insufficient capacity available to maintain power system security and reliability, it may acquire additional Supplementary Reserve Capacity. Supplementary Reserve Capacity contracts may have alternative pricing arrangements to the Reserve Capacity Price mechanism in Section 7.6, but will have a term of not more than 12 weeks.

AEMO can seek Supplementary Reserve Capacity through a tendering process; 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.

The procurement will only be open to demand-side and Energy Producing System options that are not currently Registered Facilities; and existing demand-side and Energy Producing System options, but only to the extent that the relevant capacity is not associated with Capacity Credits in the current Reserve Capacity Cycle.

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 Reserve 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 Reserve Capacity to be provided by parties that are not Rule Participants. A standard Supplementary Capacity Contract exists, but AEMO can negotiate variations to the standard conditions where this is required to secure sufficient capacity or to minimise costs.

The costs of Supplementary Reserve 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 Facilities comprising Loads as well as 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 Season²⁰. Hence, the higher a Participant's consumption during peak intervals, the higher its contribution towards funding Reserve Capacity.

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.

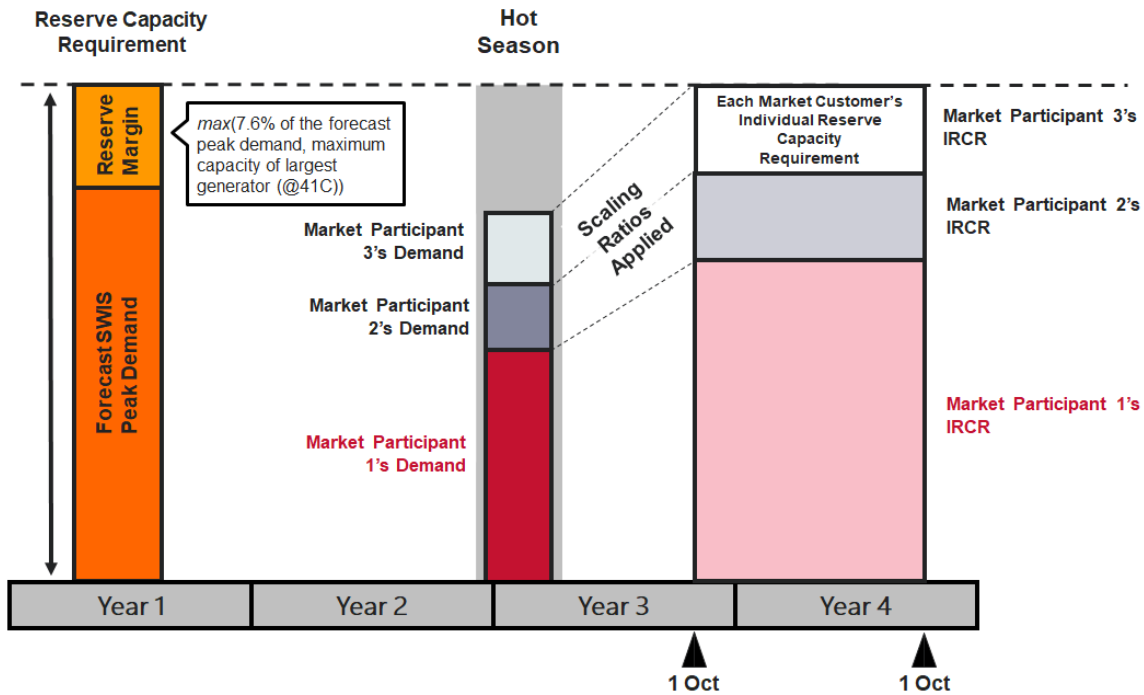
A Market Participant's IRCR equals its contribution to system peak load, plus an additional reserve margin: 30% for Loads which are temperature-dependent, and 10% for Loads which are not temperature-dependent. Intermittent Loads are a special (grandfathered) case and are explained further below.

²⁰ The Hot Season spans 1 October of a given year to 31 March of the following year.

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.

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 are 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 to the extent this is not offset through AEMO claiming Reserve Capacity Security posted by a provider of Capacity Credits that fails to satisfy its obligations,
- Less any refunds paid by 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.

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.

7.8.3 Intermittent Loads

Intermittent Loads (existing embedded Loads with self-supplying Energy Producing Systems) have grandfathered arrangements with respect to funding Reserve Capacity. 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

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 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

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.

Facilities that have been 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.
- Electric Storage Resource components of a Facility are tested twice per year. They 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.
- Demand Side Programmes 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 must conduct Reserve Capacity tests for each Facility at least twice a year (other than DSPs, which are tested once a year), and can do this by either observation (during real-time dispatch of Facilities), or by verification (by issuing instructions).

AEMO may conduct Reserve Capacity Tests by either observation (during real-time dispatch of Facilities), or by scheduled testing.

Facilities that fail their first test will be subject to a second test. If the Facility fails the second test, AEMO will reduce its Capacity Credits accordingly.

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 Net Contract Position (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 Frequency Operating Standards.
- 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

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. A 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.

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 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

do 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 10.6.

Prices in RTM Submissions:

- Are generally made by the Participant as at the network connection point for the Facility²¹.
- 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.
- 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' Facilities²² 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 make RTM Submissions for Non-Scheduled Facilities, but if they do, the expected Injection (Withdrawal) quantity must be priced at the Energy Offer Price Ceiling (Energy Offer Price Floor). This helps improve accuracy of scheduling and dispatch. Output from other Non-Scheduled Facilities is accounted for in the Forecast Operational Demand.

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. AEMO combines this with the Facility's RCOQ to determine an effective RTM Submission for use in the Dispatch Algorithm, with DSP response priced at the Energy Offer Price Ceiling. 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

The Dispatch Algorithm is the core of the RTM. It is the method by which AEMO dispatches Generators, Loads, and 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

²¹ 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 have to account for any distribution Loss Factors in their submissions,

²² Facilities which can:

- Synchronise and ramp to minimum generation within 30 minutes of receiving a Dispatch Instruction, and
- Shut down within 60 minutes of the initial Dispatch Instruction.

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.

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 8.8) 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 full description of the Dispatch Algorithm published by AEMO under WEM Rule 7.2.5.

8.3.1 Mathematical Formulation

WEM Rule 7.2.4 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 the optimisation. In the WEM, the goal is to maximise the value of market trading. Maximising the value of 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 Equations²³, and ensure that the Dispatch Algorithm:

²³ Constraint Equations usually use the ‘greater than or equal to’ operator rather than the ‘equal to’ operator, as this simplifies the optimisation process.

- Respects network equipment limits. Examples of the form of Constraint Equations for network constraints are given in Section 6.6.2.
- Meets the total energy demand, through an ‘energy balance constraint’, in the form:

$$\sum_{f \in \text{Facilities}} \text{energyDispatch}_f = \text{demandForecast}$$

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

$$\text{energyDispatch}_{\text{Facility1}} \leq \text{actualSCADA}_{\text{Facility1}} + \text{rampCapability}_{\text{Facility1}}$$

$$\text{energyDispatch}_{\text{Facility1}} \geq \text{actualSCADA}_{\text{Facility1}} - \text{rampCapability}_{\text{Facility1}}$$

- 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:

$$\sum_{f \in \text{Facilities}} \text{regulationRaiseDispatch}_f \geq \text{regulationRaiseRequirement}$$

$$\sum_{f \in \text{Facilities}} \text{regulationLowerDispatch}_f \geq \text{regulationLowerRequirement}$$

$$\sum_{f \in \text{Facilities}} \text{contingencyReserveLowerDispatch}_f \geq \text{contingencyReserveLowerRequirement}$$

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:

$$\sum_{f \in \text{Facilities}} \text{contingencyReserveRaiseDispatch}_f - \text{energyDispatch}_{\text{Facility1}} \geq 0$$

$$\sum_{f \in \text{Facilities}} \text{contingencyReserveRaiseDispatch}_f - \text{energyDispatch}_{\text{Facility2}} \geq 0$$

...

$$\sum_{f \in \text{Facilities}} \text{contingencyReserveRaiseDispatch}_f - \text{energyDispatch}_{\text{FacilityN}} \geq 0$$

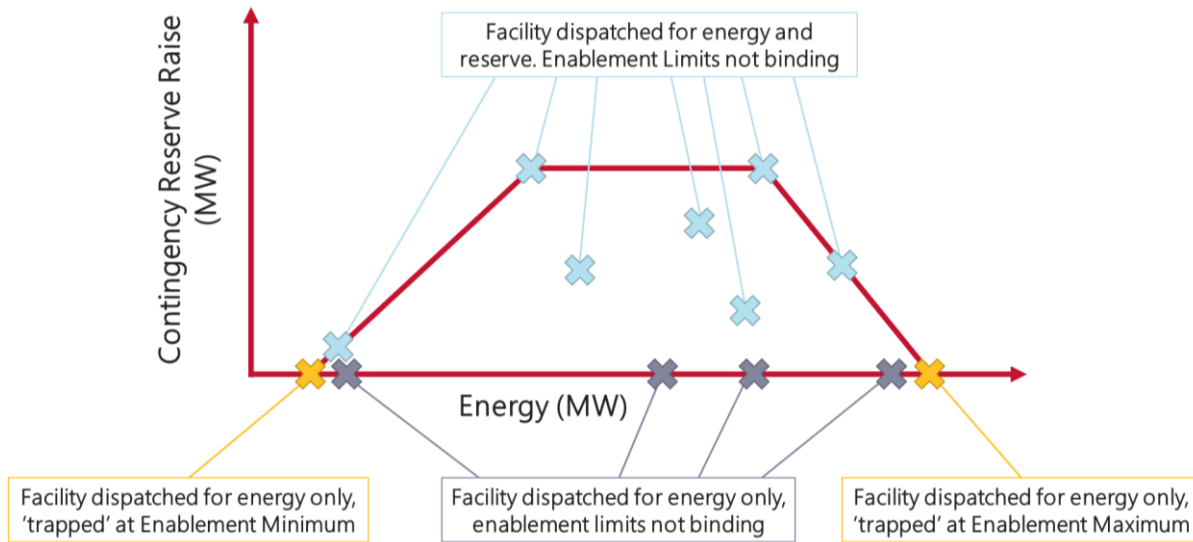
The Dispatch Algorithm can also include Contingency Reserve Raise Constraint Equations to cover Network Contingencies which would result in the loss of multiple Facilities. These equations take a similar form, but also include a term for the load that would be lost with a network element.

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 Maximum²⁴.

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.

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 Factors 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

²⁴ AEMO will inform 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 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 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).

contingency (by affecting Facility Performance Factors), and to reduce the overall Contingency Reserve Raise requirement (by affecting Contingency Factors).

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

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 300 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 11.4.1.

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.
- 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. 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 11.4).

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 offer construction.

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 which 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 (\$/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	Facility 1 parameters			Facility 2 parameters		
	Maximum capacity	50 MW		Maximum capacity	100 MW	
		Price (\$/MW)	Quantity (MW)		Price (\$/MW)	Quantity (MW)
Energy demand 100 MW	Energy offer	100	50	Energy offer	500	100
Reserve requirement 25 MW	Reserve offer	0	50	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

$$\begin{aligned}
 TotalCost = & \text{energyDispatch}_{Facility1} \times \text{energyOfferPrice}_{Facility1} \\
 & + \text{energyDispatch}_{Facility2} \times \text{energyOfferPrice}_{Facility2} \\
 & + \text{reserveDispatch}_{Facility1} \times \text{reserveOfferPrice}_{Facility1} \\
 & + \text{reserveDispatch}_{Facility2} \times \text{reserveOfferPrice}_{Facility2}
 \end{aligned}$$

subject to:

Equation 8: energy balance constraint for dispatch examples

$$\sum_{f \in Facilities} \text{energyDispatch}_f \geq \text{demandForecast}$$

Equation 9: reserve requirement constraint for dispatch examples

$$\sum_{f \in \text{Facilities}} \text{reserveDispatch}_f \geq \text{reserveRequirement}$$

Equation 10: joint capacity constraints for dispatch examples

$$\begin{aligned} \text{energyDispatch}_{\text{Facility1}} + \text{reserveDispatch}_{\text{Facility1}} &\leq \text{maximumCapacity}_{\text{Facility1}} \\ \text{energyDispatch}_{\text{Facility2}} + \text{reserveDispatch}_{\text{Facility2}} &\leq \text{maximumCapacity}_{\text{Facility2}} \end{aligned}$$

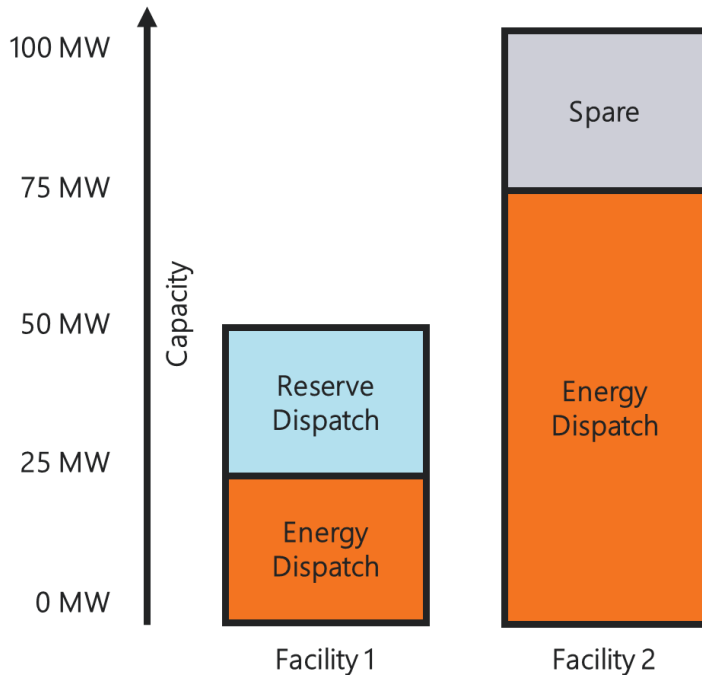
Outputs

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:

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

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.

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

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).

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

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

Payments

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

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

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

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

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

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

In this example, Facility 2 is offering to provide reserve. As a result, Facility 1 can be completely dispatched for energy. The optimisation problem has the same setup as for example 1.

Inputs

System parameters		Facility 1 parameters		Facility 2 parameters			
		Price (\$/MW)	Quantity (MW)	Price (\$/MW)	Quantity (MW)		
Energy demand	100 MW						
Reserve requirement	25 MW						
		Maximum capacity	50 MW	Maximum capacity	100 MW		
		Energy offer	100	50	Energy offer	500	100
		Reserve offer	0	50	Reserve offer	0	100

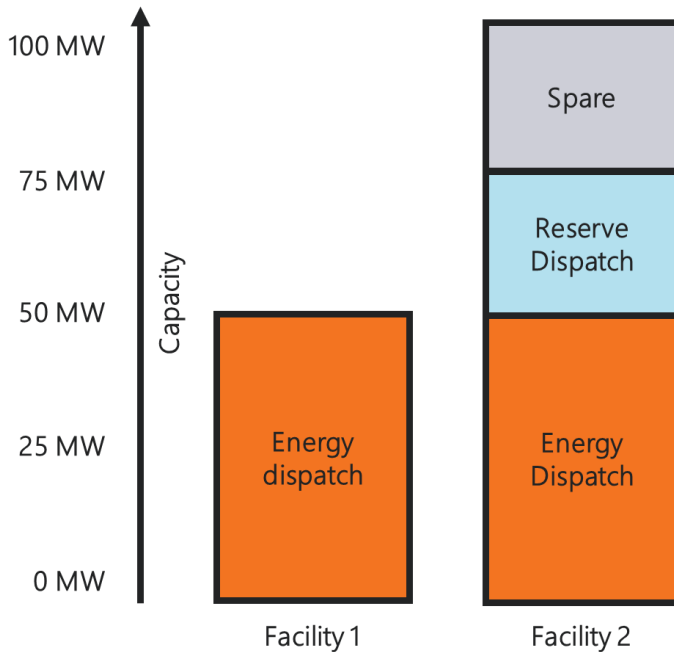
Outputs

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:

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

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.

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

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.

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

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

Payments

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

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

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

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

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

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

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 Interval²⁵.
- 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.

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.

²⁵ AEMO can exempt Facilities from this requirement where supported by evidence that the Facility is not capable of linear ramping.

8.7 Scarcity and intervention

When supply of energy or ESS is scarce, or where power system security 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, or even by connecting to the SWIS to provide energy or FCESS that it otherwise would not have.

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.

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 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 information²⁶, 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 4.

Table 4 Market Schedules

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

²⁶ 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.

Schedule	Horizon	Resolution	Frequency	Notes
				'Available' facility capacity that still has time to synchronise according to standing data start-up times.
Week-Ahead Schedule	7 days	30 minutes	Daily	Provides indicative information to end of feasible short-term load forecast horizon.

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.

8.9 Market Advisories

AEMO must inform Rule Participants and the public of current or impending situations that could affect power system security or reliability, 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 Power System Security 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.

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.

8.10 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

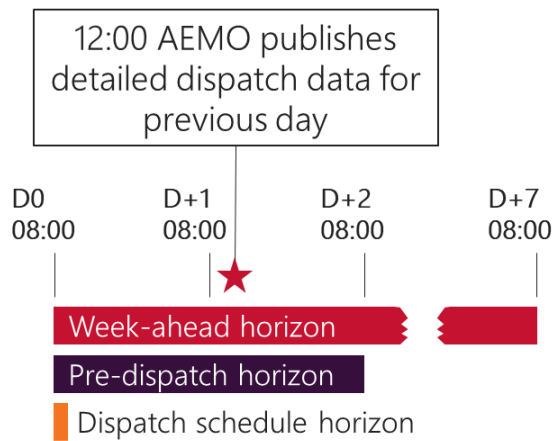
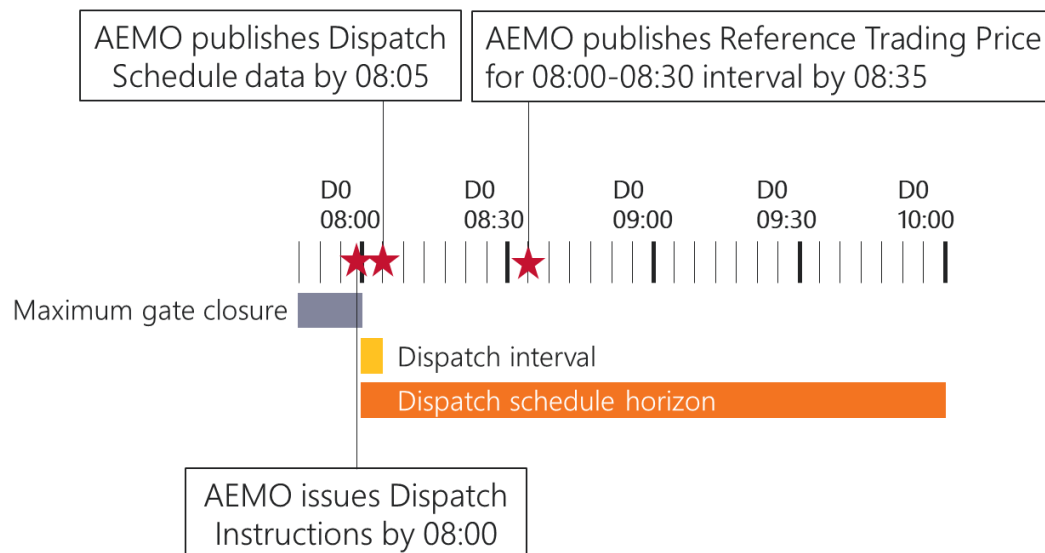


Figure 18 Dispatch activities



9. The Short-Term Energy Market

9.1 Overview

The STEM is a 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 persons for the sale of electricity by one person 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

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 before the Bilateral Submission Cutoff – usually 8.50 am on the Scheduling Day.

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 Factors²⁷, 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.

²⁷ Determined by Western Power.

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.

9.3.2 STEM Submissions

Market Participants can make STEM Submissions at any time before the STEM Submission Cutoff – usually 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 next week:

- The quantity of Capacity Credits held.
- 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 sum of the Loss Factor adjusted Available Capacity and In-Service Capacity offered into the RTM by the Market Participant's Facilities, which represents the limit on what the participant can offer to supply in the STEM.
- The Maximum Consumption Capability, which represents the limit on what the participant can bid to purchase in the STEM.
- The expected Loss Adjusted demand as published in the most recent Pre-Dispatch Schedule or Week-Ahead Schedule.

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:

- A Fuel Declaration – this states what fuel each dual-fuelled Facility was assumed to be using when forming the Portfolio Supply Curve. This is required because liquid fuelled generation can be offered at a higher price than non-liquid-fuelled generation. To the extent that actual fuel use on the day differs from what was declared, the ERA may follow up.
- 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. If this portfolio is made up of 200 MW of Facilities operating on non-liquid fuel (e.g. gas or coal) and 50 MW of Facilities operating on liquid fuel (e.g. distillate or oil), then the first 200 MW of the supply curve must contain prices less than or equal to the Maximum STEM Price, while the last 50 MW must contain prices less than or equal to the Alternative Maximum STEM Price. All prices must be greater than or equal to the Minimum STEM Price. 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 prices must be greater than or equal to the Minimum STEM Price, less than or equal to the Alternative Maximum STEM price 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

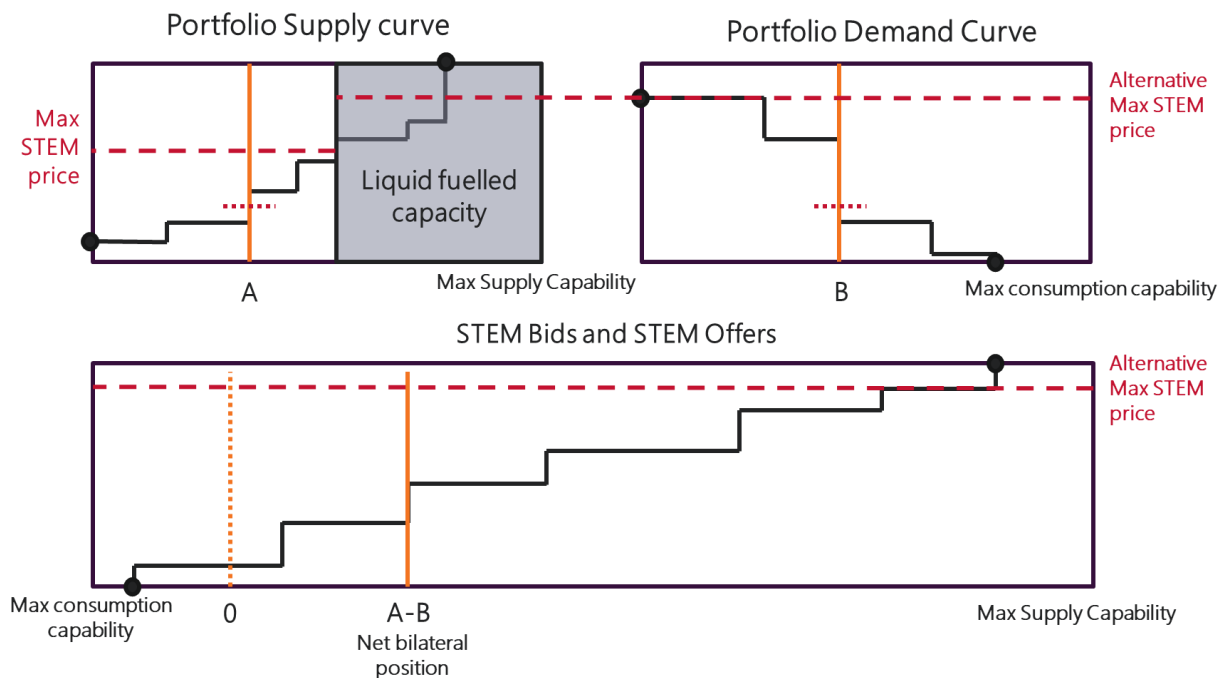
AEMO runs the STEM Auction using accepted STEM Submissions and publishes results before the STEM Results Deadline – usually 11.30 am on the Scheduling day.

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.

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:

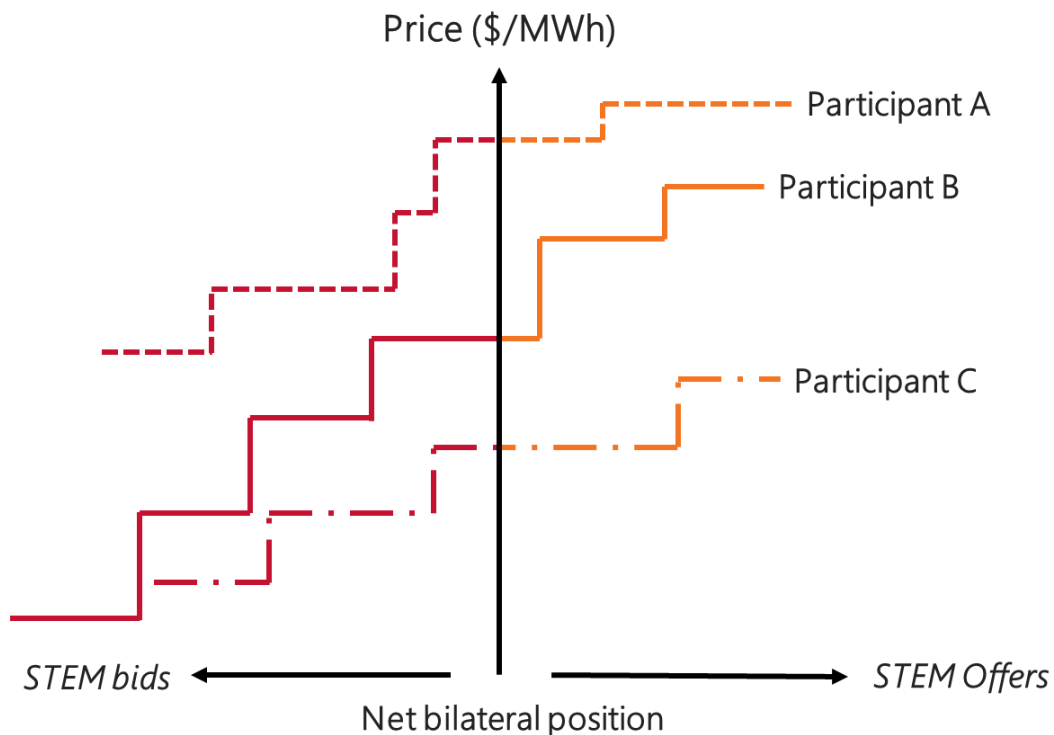
- The minimum price that can be included in a submission is the Minimum STEM Price.
- The maximum price that can be included in a submission is the Alternative Maximum STEM Price.
- The shaded area of the Portfolio Supply Curve shows the capacity that is liquid-fuelled and which can therefore be offered up to the Alternative Maximum STEM Price. Other capacity can only be offered up to the Maximum STEM Price.
- 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 discussion that follows assumes that Participant A is a generator only; the nature of Participants B and C is not relevant:

- The three Participants are unlikely to have exactly the 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

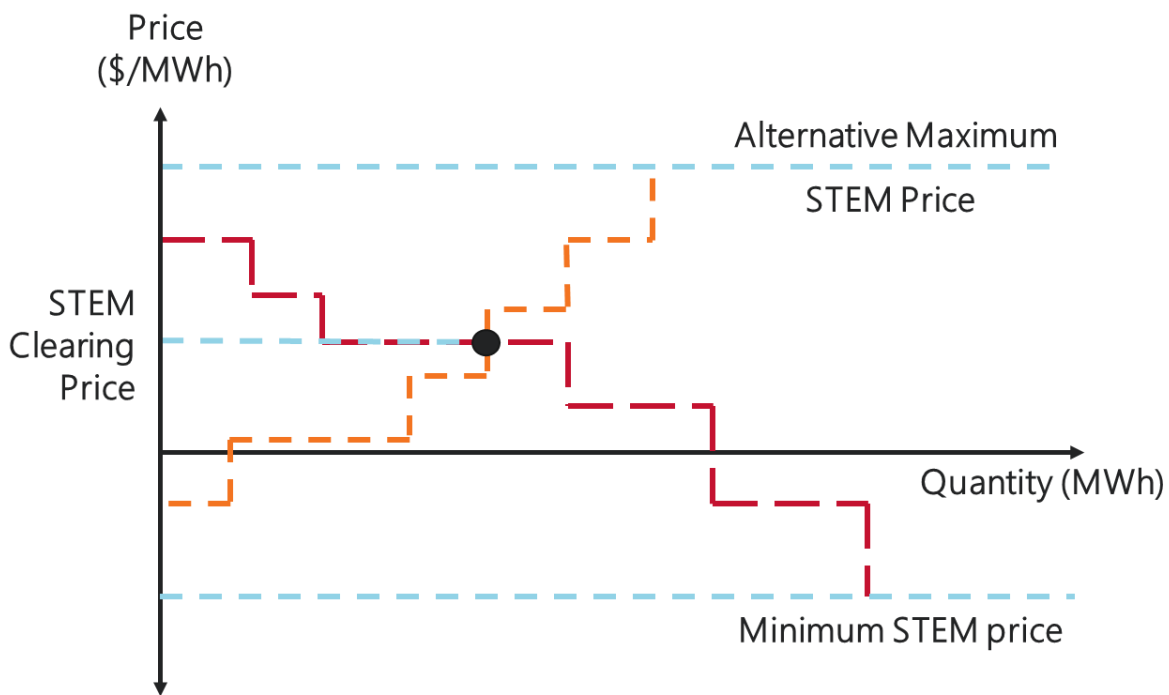


Figure 21 shows the same information as Figure 20, but the information has been re-organised to show the point where the total STEM Bids accepted equals the total STEM Offers accepted. It is apparent that the first step of Participant C's STEM Offer is fully scheduled, being used to offset the energy 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.

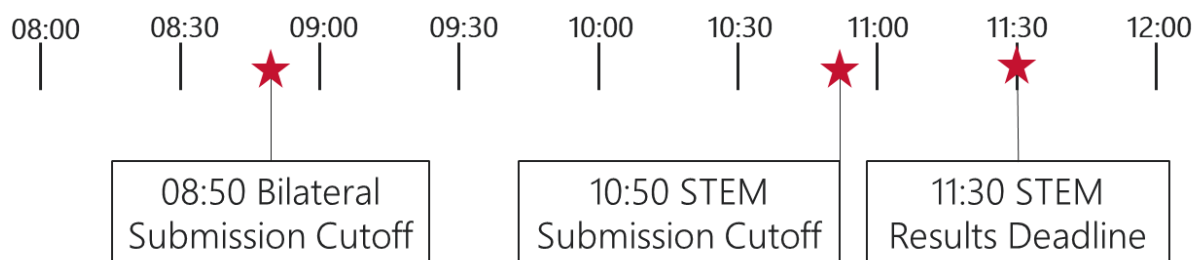
Once the STEM has been cleared, each Market Participant will have a NCP equal to its NBP as modified by its net purchase or sale in the STEM.

9.5 The STEM timetable

Figure 22 shows the relevant deadlines for the STEM on the Scheduling Day.

The Bilateral Submission Cutoff, the STEM Submission Cutoff, 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. The Supplementary Essential System Services Mechanism

10.1 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 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 providing a credible threat of competitive entry.
 - 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.

10.2 Triggering the SESSM

The SESSM 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.

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

When the SESSM is triggered 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.

10.3 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.

10.4 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.

10.5 Determining SESSM awards

AEMO selects SESSM submissions which 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.

10.6 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 Availability Quantity.
- The FCESS offer price must not exceed the 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 pre-award 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 Offer Cap.

10.7 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 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.

10.8 Expressions of interest process

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

AEMO provides information about historical requirements for FCESS, and 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.

11. Settlement

11.1 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 11.4.

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 11.2.

11.2 Settlement timing

11.2.1 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.

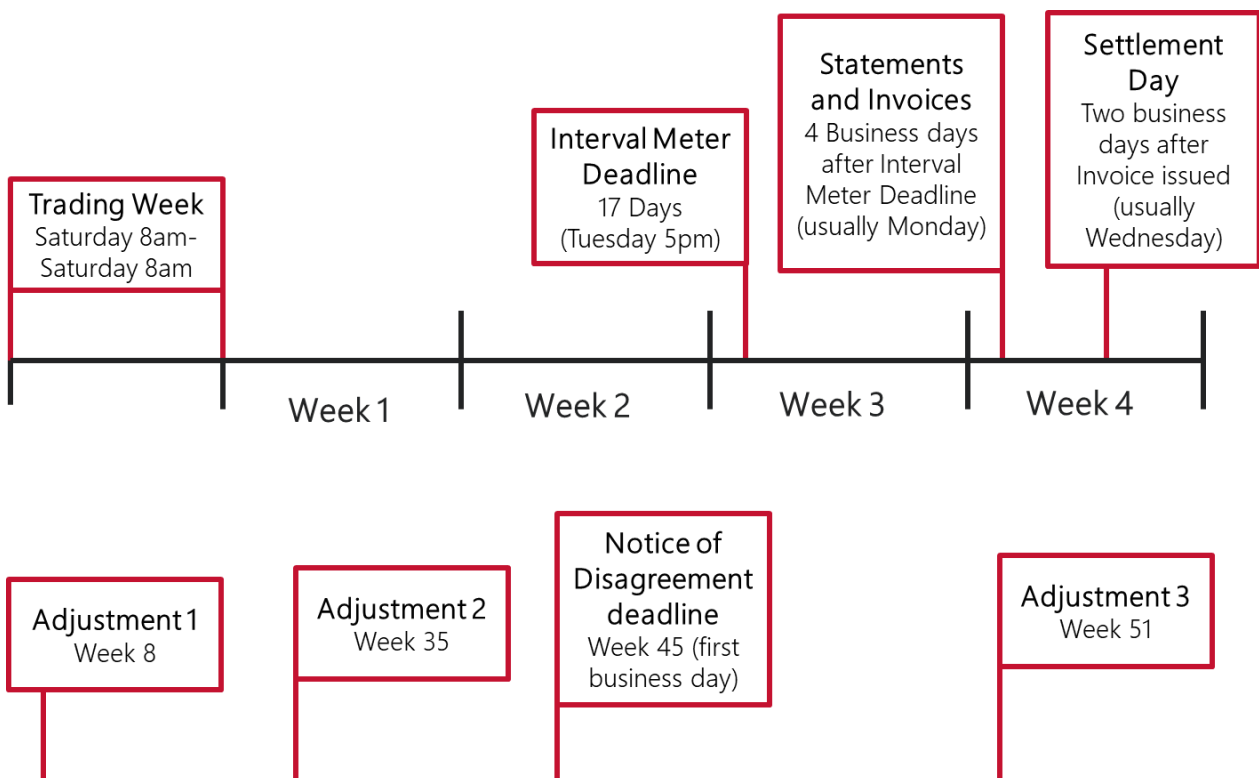
11.2.2 Settlement timeline

The weekly settlement timeline is illustrated in Figure 23:

- The Interval Meter Deadline is 17 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 Western Power is unable to submit meter readings within the required timeframe. For these meters, Western Power 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 4.4).

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.

11.3 Metered Schedules

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 Facilities²⁸ 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 Factors²⁹ to the unadjusted meter reading, so that it is loss-adjusted to the Reference Node (see also Section 9.3.1).

²⁸ This excludes DSPs (which are settled for Reserve Capacity payments only) and Interruptible Loads (which are settled on ESS enablement quantities only).

²⁹ Determined by Western Power.

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 Synergy³⁰, 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.

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.

11.4 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.

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 5 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 4.3). 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.

³⁰ End-use customers with an annual consumption of below 50MWh are captive customers that are served by Synergy by default.

Table 5 Overview of settlement segment and amounts

Settlement segment	Description	Paid to	Recovered from
Short-Term Energy Market	<p>Settled based on scheduled offers and bids, and STEM Price from STEM Auction.</p> <p>Does not require Metered Schedules as settlement amounts are based on STEM Auction results.</p>	Market Participants who have a positive STEM Quantity (net seller)	Market Participants who have a negative STEM Quantity (net purchaser)
Reserve Capacity	<p>Reserve Capacity settlement comprises two components:</p> <ul style="list-style-type: none"> • Payments to capacity providers • Payments from capacity purchasers 	<p>Capacity providers are those Market Participants who have been assigned Capacity Credits. Payments to providers comprise:</p> <ul style="list-style-type: none"> • A payment for capacity based on <ul style="list-style-type: none"> – 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 Reserve Capacity Payments (see Section 7.7) • Excess allocation payments, where a participant has been allocated Capacity Credits over and above their IRCR 	<p>Payments to capacity providers are cost-recovered via:</p> <ul style="list-style-type: none"> • 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 Reserve Capacity. This is allocated to all Market Participants in proportion to their IRCR (see Section 7.8.2).
Energy	<p>Energy settlement comprises two components:</p> <ul style="list-style-type: none"> • Energy payments settled based on a participant’s Metered Schedule, its NCP, and the Reference Trading Price for a Trading Interval. <ul style="list-style-type: none"> – The Reference Trading Price for a 30 minute Trading Interval is the average of the 5 minute Market Clearing 	<ul style="list-style-type: none"> • 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. 	<ul style="list-style-type: none"> • 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

Settlement segment	Description	Paid to	Recovered from
	<p>Prices for energy calculated by the Dispatch Algorithm for all Dispatch Intervals contained in the Trading Interval</p> <ul style="list-style-type: none"> – The NCP reflects the participant’s level of Bilateral Contract coverage and can reduce exposure to the market price. • Energy Uplift Payment. This is a payment made to compensate or make whole) energy producers who are dispatched behind a binding network constraint, as a result 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 11.4.1 below 		Trading Interval in proportion to their consumption.
Essential System Services	<p>Two groups of ESS are settled in the WEM:</p> <ul style="list-style-type: none"> • FCESS comprises Contingency Reserve Raise, Contingency Reserve Lower, RoCoF Control Service, Regulation Raise and Regulation Lower • NCESS currently comprises only System Restart Services but could be used to procure other locational services as the need emerges. 	<p>There are two components to payments made to Market Participants who provide FCESS</p> <ul style="list-style-type: none"> • 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 10.4 and 10.7 for more details on Availability Payments and SESSM refunds. <p>Providers of System Restart Services are paid a fixed amount per Trading Interval as contractually agreed between the provider and AEMO.</p>	<p>FCESS 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.</p> <p>See Sections 11.4.2 and 11.4.3 below for further details on the approach to Contingency Reserve Raise and RCS cost recovery.</p>
Market Fees	Market Fees are calculated in \$/MWh using separate fee rates for AEMO, the Coordinator and the ERA (see Section 4.5)	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
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.	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.

11.4.1 Energy Uplift Payment

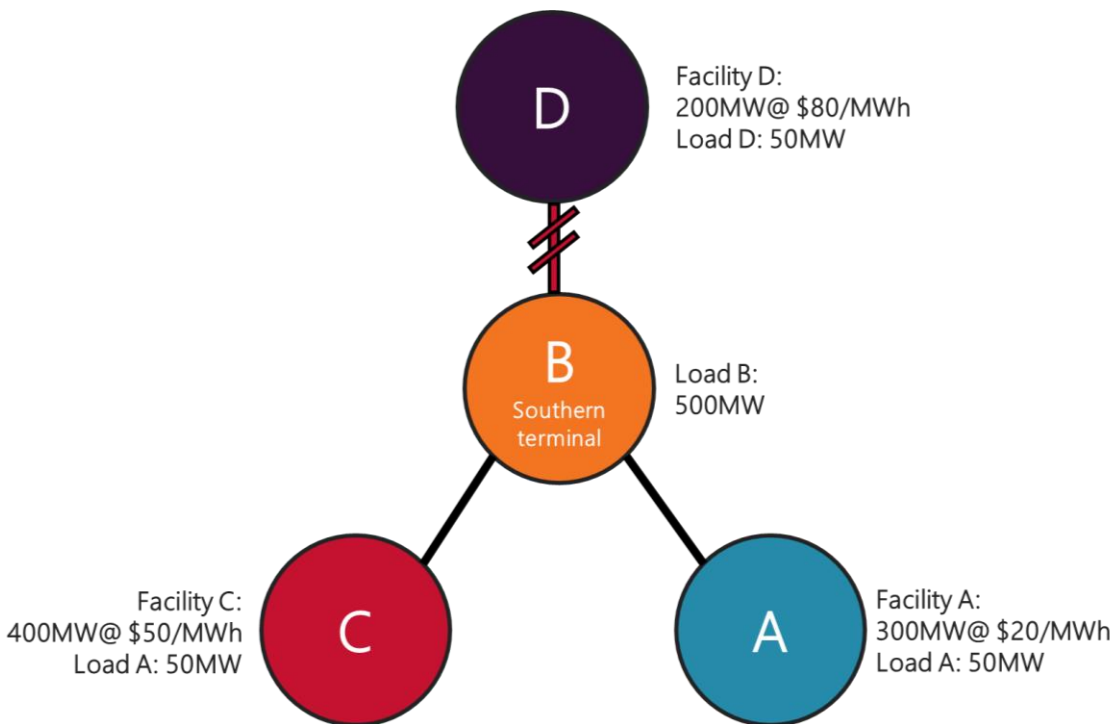
As discussed in Section 8.4:

- 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.

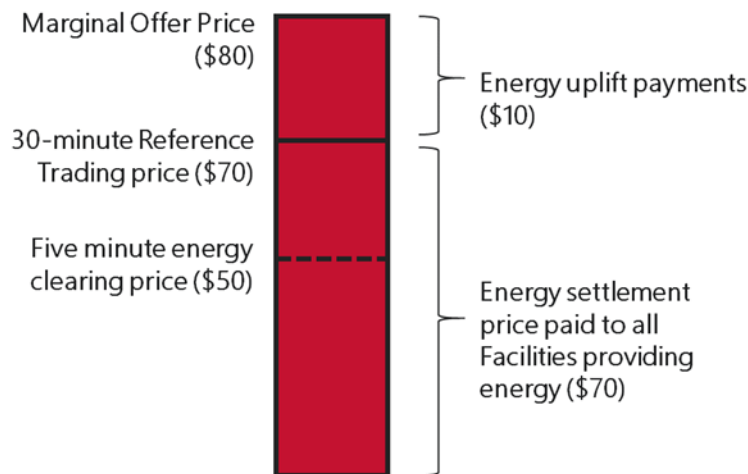
Figure 24 Example of mispricing



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:

- 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.

Figure 25 Example of Uplift Price calculation



- 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.

11.4.2 Runway allocation

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 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’.

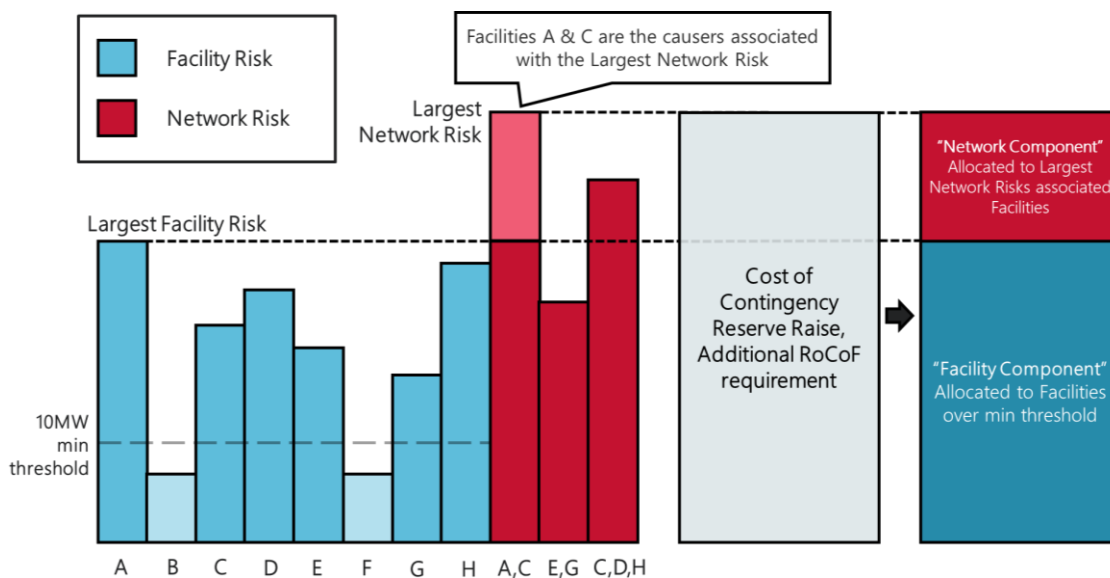
As noted in Section 8.3, the Contingency Reserve Raise requirement is set by the Largest Credible Supply Contingency, which can be:

- An energy producing Facility (that is, a Facility Contingency representing loss of generation from a single Facility). The amount of energy and ESS (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 as a result of loss of one or more lines. The amount of cleared energy, ESS (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 26³¹.

³¹ 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.

- 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.

Figure 26 Allocation of costs to Facility Risks and Network Risks



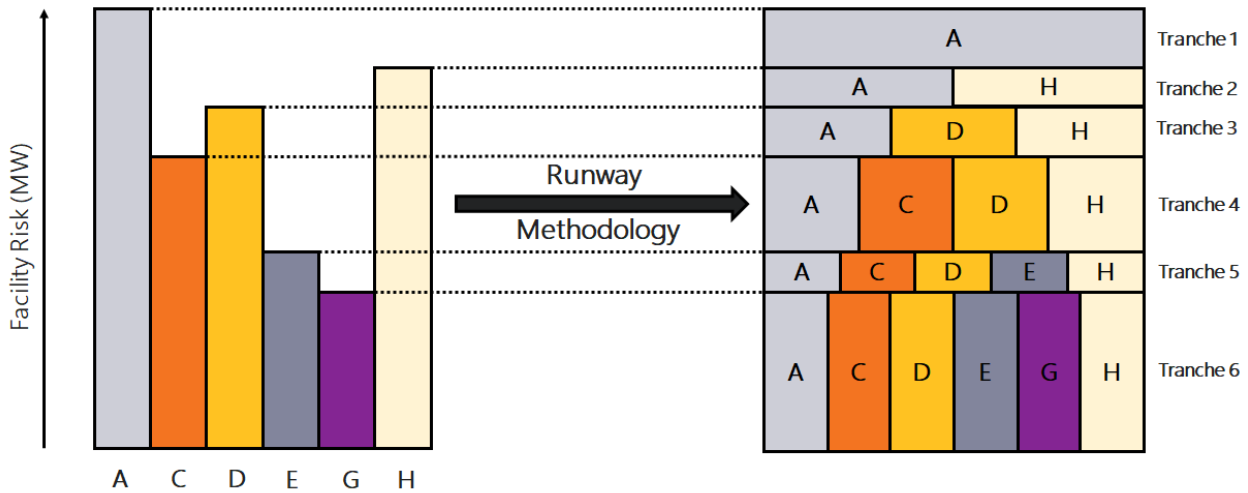
The runway method allocates contingency reserve costs to causers of contingencies, commensurate with the extent to which they have contributed to the *additional* procurement Contingency Reserve Raise Requirement.

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.

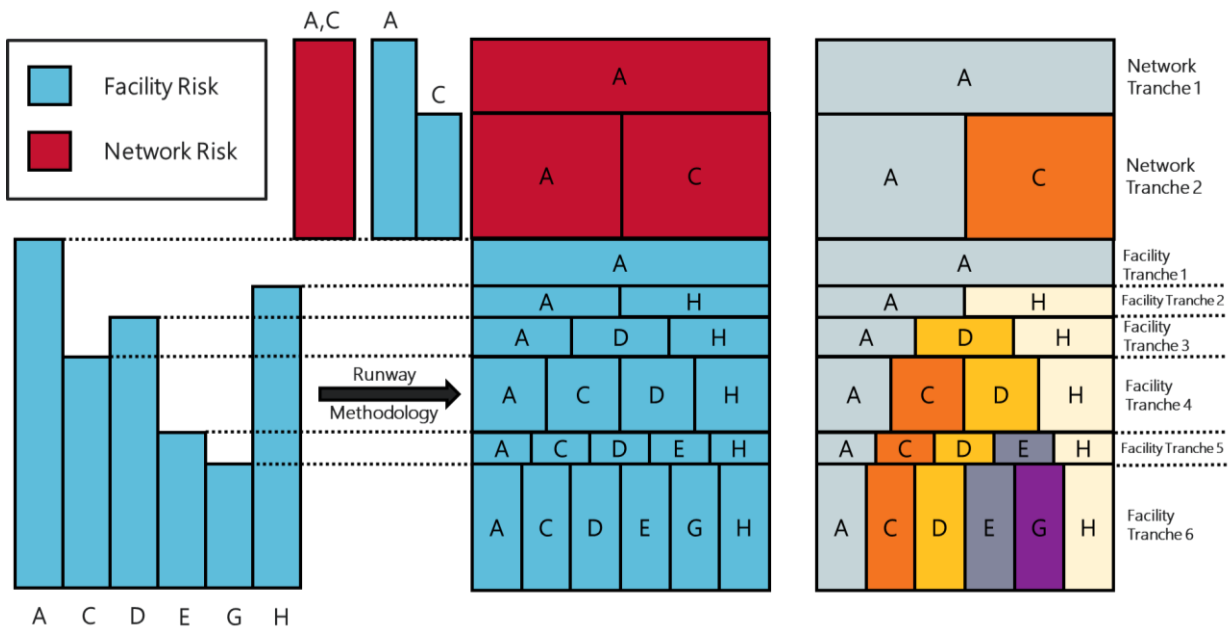
A given Facility's share of the cost can be calculated by summing its share across all six tranches.

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



11.4.3 RoCoF cost recovery

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 or 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 ms 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.

11.5 Default

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 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 Operators	AEMO	The Coordinator of Energy	ERA	Network Operators	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)										

Market process	Administrator of process				Parties to process					
	AEMO	The Coordinator of Energy	ERA	Network Operators	AEMO	The Coordinator of Energy	ERA	Network Operators	Market Participants selling WEM services	Market Participants consuming WEM services
Supplementary Reserve Capacity Procurement	x								x	
Non Co-optimised Essential System Services	x	x		x	x	x	x	x	x	
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 Power System Security and Power System Reliability	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	

Market process	Administrator of process				Parties to process					
	AEMO	The Coordinator of Energy	ERA	Network Operators	AEMO	The Coordinator of Energy	ERA	Network Operators	Market Participants selling WEM services	Market Participants consuming WEM services
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	
Facility Testing – Commissioning and Reserve Capacity Tests	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.

A2.1 Example 3a: 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		Facility 1 parameters			Facility 2 parameters		
			Price (\$/MW)	Quantity (MW)		Price (\$/MW)	Quantity (MW)
Energy demand	100 MW	Maximum capacity	50 MW	Maximum capacity	100 MW		
Reserve requirement	25 MW	Minimum enablement	20 MW				
		Energy offer	500	50	Energy offer	100	100
		Reserve offer	0	30	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

$$energyDispatch_{Facility1} \geq minimumEnablementLimit_{Facility1}$$

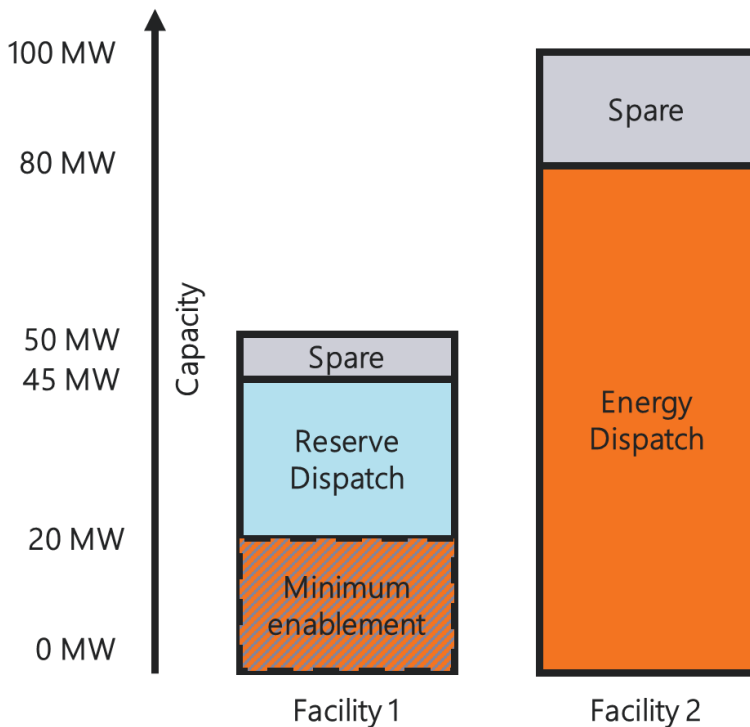
Outputs

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 3a dispatch



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

$$\text{TotalCost} = 20 \times \$500 + 80 \times \$100 + 25 \times \$0 + 0 \times \$0 = \$18,000$$

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.

$$\text{TotalCost} = 20 \times \$500 + 81 \times \$100 + 25 \times \$0 + 0 \times \$0 = \$18,100$$

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.

$$\text{TotalCost} = 20 \times \$500 + 80 \times \$100 + 26 \times \$0 + 0 \times \$0 = \$18,000$$

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.

- Minimum enablement 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).

$$\text{TotalCost} = 21 \times \$500 + 79 \times \$100 + 5 \times \$0 + 20 \times \$0 = \mathbf{\$20,400}$$

The change in total costs would be \$400, and this is the shadow price on the minimum enablement constraint for Facility 1.

Payments

Facility 1 revenue is $20 \text{ MW} \times \$100 + 25 \text{ MW} \times \$0 = \$2,000$

Facility 1 costs are $20 \text{ MW} \times \$500 + 25 \text{ MW} \times \$0 = \$10,000$

Facility 1 profit is $\$2,000 - \$10,000 = -\$8,000$

Facility 2 revenue is $80 \text{ MW} \times \$100 + 0 \text{ MW} \times \$0 = \$8,000$

Facility 2 costs are $80 \text{ MW} \times \$100 + 0 \text{ MW} \times \$0 = \$8,000$

Facility 2 profit is $\$8,000 - \$8,000 = 0$

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.

As the only reserve provider, Facility 1 decides to increase its reserve offer price to account for the 'enablement losses' in the energy market, as seen in example 3b.

A2.2 Example 3b: Including enablement losses in reserve offer price of sole reserve provider

In this example, Facility 1 adjusts its reserve offer to account for enablement losses in the energy market. The dispatch outcome is the same as Example 3a, but the reserve price is different.

Inputs

Facility 1 adjusts its reserve offer to incorporate the expected enablement losses over its expected reserve dispatch from example 3a: $\$8,000 \text{ divided by } 25 \text{ MW} = \320 per MW .

System parameters	Facility 1 parameters			Facility 2 parameters		
		Price (\$/MW)	Quantity (MW)		Price (\$/MW)	Quantity (MW)
Energy demand	100 MW			Maximum capacity		100 MW
Reserve requirement	25 MW			Energy offer	100	100
				Reserve offer	0	0

Optimisation problem

The optimisation problem is the same as for Example 3a.

Outputs

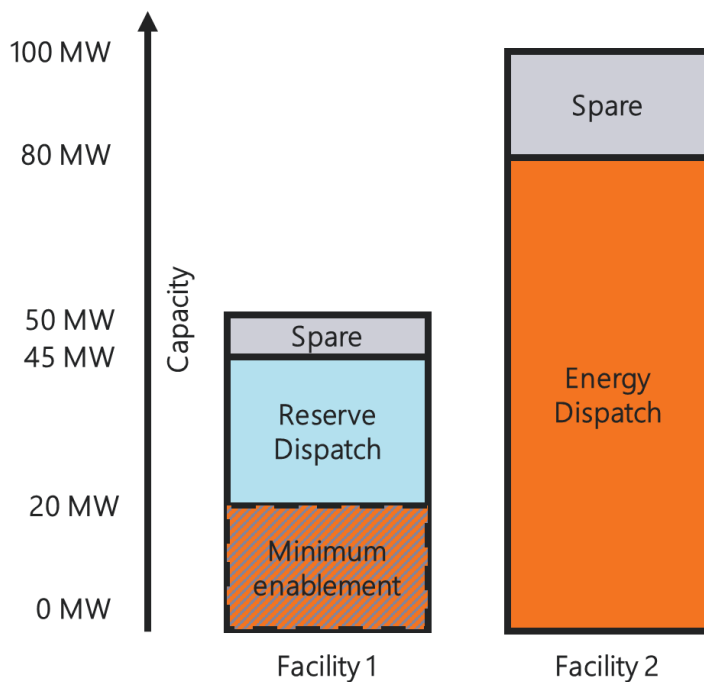
Dispatch

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.

The dispatch outcome is the same as example 3a:

- Facility 1 Energy dispatch: 20 MW, reserve dispatch: 25 MW.
- Facility 2 Energy dispatch: 80 MW, reserve dispatch: 0 MW.

Figure 30 Co-optimisation Example 3b dispatch



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

$$\text{TotalCost} = 20 \times \$500 + 80 \times \$100 + 25 \times \$320 + 0 \times \$0 = \$26,000$$

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, at the same offer price as in example 3a. Facility 1 is the marginal Facility for reserve, but now at a non-zero price. The two markets do not interact.

- *Energy*: If demand increased by 1 MW (to 101 MW), Facility 2 would be dispatched for one more MW, and the total cost would rise by \$100.

$$\text{TotalCost} = 20 \times \$500 + 81 \times \$100 + 25 \times \$320 + 0 \times \$0 = \$26,100$$

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.

$$\text{TotalCost} = 20 \times \$500 + 80 \times \$100 + 26 \times \$320 + 0 \times \$0 = \$26,320$$

The change in total costs would be \$320, so this is the marginal price for reserve.

Facility 1's minimum enablement constraint is binding, so it has a shadow price, which still does not flow through into the energy or reserve prices (which is why Facility 1 has increased its reserve offer).

- Minimum enablement 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. Facility 2 would be backed off for energy but would not provide any more reserve.

$$\text{TotalCost} = 21 \times \$500 + 79 \times \$100 + 25 \times \$320 + 0 \times \$0 = \$26,400$$

The change in total costs would be \$400/MW, and this is the shadow price on the minimum enablement constraint for Facility 1.

Payments

Facility 1 revenue is $20 \text{ MW} \times \$100 + 25 \text{ MW} \times \$320 = \$10,000$

Facility 1 costs are $20 \text{ MW} \times \$500 + 25 \text{ MW} \times \$0 = \$10,000$ (Facility 1 variable costs to provide reserve are still zero, though the offer is \$320 to account for energy market losses)

Facility 1 profit is $\$10,000 - \$10,000 = \$0$

Facility 2 revenue is $80 \text{ MW} \times \$100 + 0 \text{ MW} \times \$320 = \$8,000$

Facility 2 costs are $80 \text{ MW} \times \$100 + 0 \text{ MW} \times \$0 = \$8,000$

Facility 2 profit is $\$8,000 - \$8,000 = \$0$

This situation (spreading enablement losses over expected ESS dispatch) is likely to occur in respect of RCS in low demand periods in the middle of a sunny day, where a single Facility providing only RCS prices its RCS offers based on enablement losses divided by expected RCS dispatch.

Examples 4a through 4d explore what would happen if Facility 2 could also provide reserve.

A2.3 Example 4a: Reserve price is zero with enablement limits

This example is the same as Example 3a, 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		Facility 1 parameters			Facility 2 parameters		
		Price (\$/MW)	Quantity (MW)		Price (\$/MW)	Quantity (MW)	
Energy demand	100 MW	500	50	100	100		
Reserve requirement	25 MW	0	30	0	80		

Optimisation problem

The optimisation problem is the same as for Example 3a, with an additional constraint to set the minimum energy dispatch level for Facility 2.

Equation 12: minimum enablement limit constraints

$$energyDispatch_{Facility1} \geq minimumEnablementLimit_{Facility1}$$

$$energyDispatch_{Facility2} \geq minimumEnablementLimit_{Facility2}$$

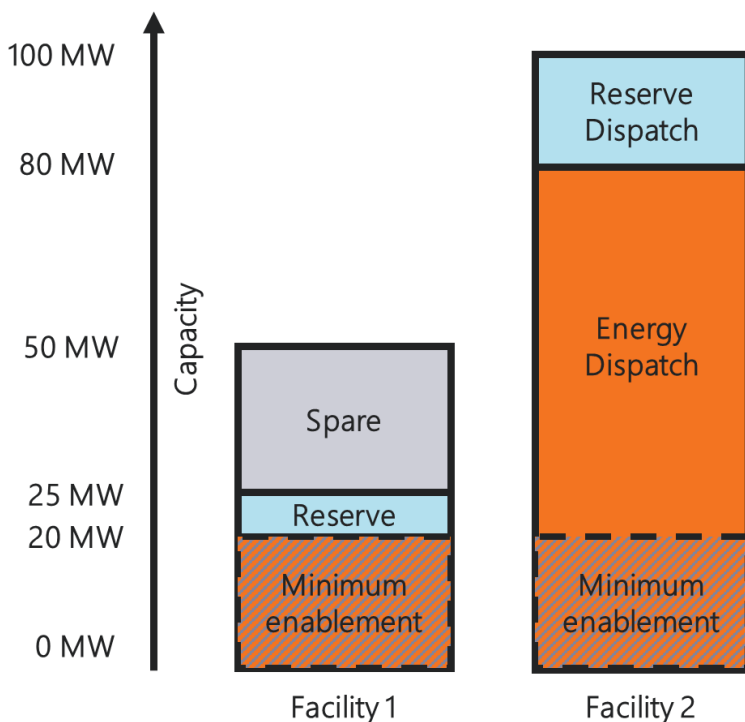
Outputs

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 31 Co-optimisation Example 4a 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.

$$\text{TotalCost} = 20 \times \$500 + 81 \times \$100 + 6 \times \$0 + 19 \times \$0 = \$18,100$$

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.

$$\text{TotalCost} = 20 \times \$500 + 80 \times \$100 + 6 \times \$0 + 20 \times \$0 = \$18,000$$

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:

- **Minimum enablement 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)

$$\text{TotalCost} = 21 \times \$500 + 79 \times \$100 + 5 \times \$0 + 20 \times \$0 = \$20,400$$

The change in total costs would be \$400, and this is the shadow price on the minimum enablement constraint for Facility 1.

- **Minimum enablement at Facility 2:** If the enablement limit increased by 1 MW (to 21 MW), dispatch would not change, because the constraint is not binding.

$$\text{TotalCost} = 20 \times \$500 + 80 \times \$100 + 5 \times \$0 + 20 \times \$0 = \$20,000$$

The total cost would stay the same, so the shadow price on the minimum enablement constraint for Facility 2 is 0.

Payments

Facility 1 revenue is $20 \text{ MW} \times \$100 + 5 \text{ MW} \times \$0 = \$2,000$

Facility 1 costs are $20 \text{ MW} \times \$500 + 5 \text{ MW} \times \$0 = \$10,000$

Facility 1 profit is $\$2,000 - \$10,000 = -\$8,000$

Facility 2 revenue is $80 \text{ MW} \times \$100 + 20 \text{ MW} \times \$0 = \$8,000$

Facility 2 costs are $80 \text{ MW} \times \$100 + 20 \text{ MW} \times \$0 = \$8,000$

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.

Facility 1 has two options:

1. Remove its reserve offers altogether, so it is not dispatched for reserve.
2. Increase its reserve offer price to account for the 'enablement losses' in the energy market.

These are explored in examples 4b and 4c.

A2.4 Example 4b: Withdrawing reserve capability to avoid enablement losses

In this example, Facility 1 removes its reserve offer, meaning Facility 2 must provide all the reserve. The dispatch result is like Example 1; even though it has the cheapest energy offer, Facility 2 must be backed

off to provide reserve. The remaining energy is provided by the more expensive Facility 1. This differs from Example 3a, where an additional unit of reserve could be provided by Facility 1 at no cost (so Facility 2 would not need to back off). Both the energy and reserve prices are affected.

Inputs

System parameters		Facility 1 parameters			Facility 2 parameters		
		Maximum capacity		50 MW	Maximum capacity		100 MW
Reserve requirement		Minimum enablement		20 MW	Minimum enablement		20 MW
		Price (\$/MW)	Quantity (MW)		Price (\$/MW)	Quantity (MW)	
Energy demand	100 MW	Energy offer	500	50	Energy offer	100	100
Reserve requirement	25 MW	Reserve offer	0	0	Reserve offer	0	80

Optimisation problem

The optimisation problem is the same as for Example 4a, but only Facility 2 has a minimum enablement limit constraint.

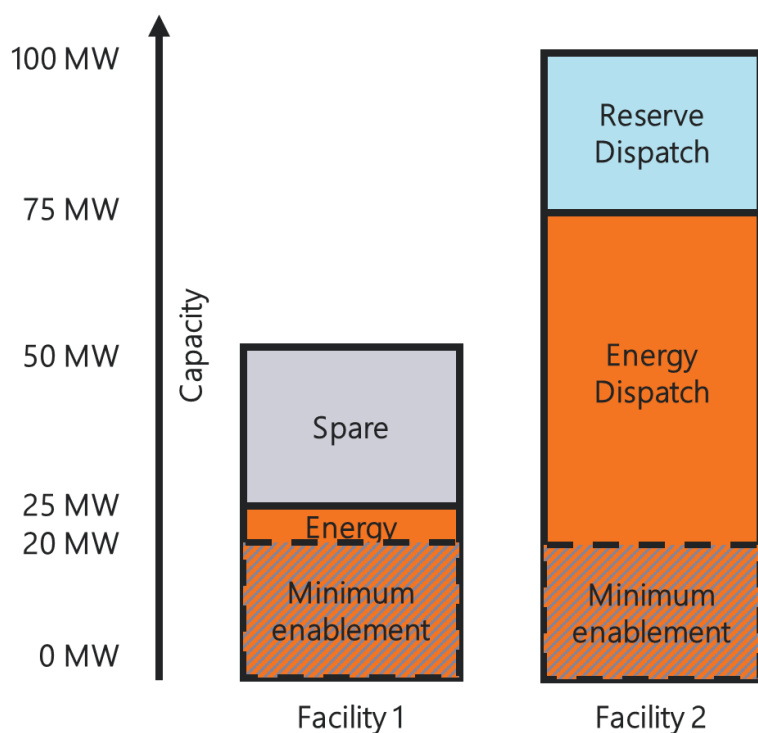
Outputs

Dispatch

Now that Facility 2 is the only reserve provider, it must be backed off to provide reserve. The cheapest way to meet the energy demand is to dispatch Facility 2 for as much energy as possible, and then dispatch Facility 1 for the remainder.

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

Figure 32 Co-optimisation Example 4b dispatch



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

$$\text{TotalCost} = 25 \times \$500 + 75 \times \$100 + 0 \times \$0 + 25 \times \$0 = \$20,000$$

Marginal prices

The marginal prices are based on the additional cost of serving another increment of the service. Facility 1 is now the marginal Facility for energy. Facility 2 is the marginal Facility for reserve (it is the only provider), and the reserve price includes the effects of the altered energy dispatch.

- *Energy*: If demand increased by 1 MW (to 101 MW), Facility 1 would be dispatched for one more MW, and the total cost would rise by \$500.

$$\text{TotalCost} = 26 \times \$500 + 75 \times \$100 + 0 \times \$0 + 25 \times \$0 = \$20,500$$

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 would have to be backed off by 1 MW energy to make room. That unit of energy would instead be provided by Facility 1 (at a cost of \$500 instead of \$100).

$$\text{TotalCost} = 26 \times \$500 + 74 \times \$100 + 0 \times \$0 + 26 \times \$0 = \$20,400$$

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

The shadow price on Facility 2's minimum enablement constraint is zero, because it is efficiently dispatched above the energy limit and dispatch would not change with an increment to the minimum enablement limit.

Payments

Facility 1 revenue is $25 \text{ MW} \times \$500 + 0 \text{ MW} \times \$0 = \$12,500$

Facility 1 costs are $25 \text{ MW} \times \$500 + 0 \text{ MW} \times \$0 = \$12,500$

Facility 1 profit is $\$12,500 - \$12,500 = \$0$

Facility 2 revenue is $75 \text{ MW} \times \$500 + 25 \text{ MW} \times \$400 = \$47,500$

Facility 2 costs are $75 \text{ MW} \times \$100 + 25 \text{ MW} \times \$0 = \$7,500$

Facility 2 profit is $\$47,500 - \$7,500 = \$40,000$

Facility 1 is no longer losing money to provide energy.

A2.5 Example 4c: Including enablement losses in reserve offer price

In this example, Facility 1 adjusts its reserve offer to account for enablement losses in the energy market. The dispatch outcome and marginal prices are the same as Example 4b, but the mechanism is slightly different.

Inputs

Facility 1 adjusts its reserve offer to incorporate the expected enablement losses over its expected reserve dispatch from example 3a: $\$8,000$ divided by $5 \text{ MW} = \$1,600$ per MW.

System parameters	Facility 1 parameters			Facility 2 parameters		
		Price (\$/MW)	Quantity (MW)		Price (\$/MW)	Quantity (MW)
	Energy demand 100 MW	Energy offer	500	50	Energy offer	100
Reserve requirement 25 MW	Reserve offer	1,600	30	Reserve offer	0	80

Optimisation problem

The optimisation problem is the same as for Example 4a. Both Facilities have minimum enablement limit constraints.

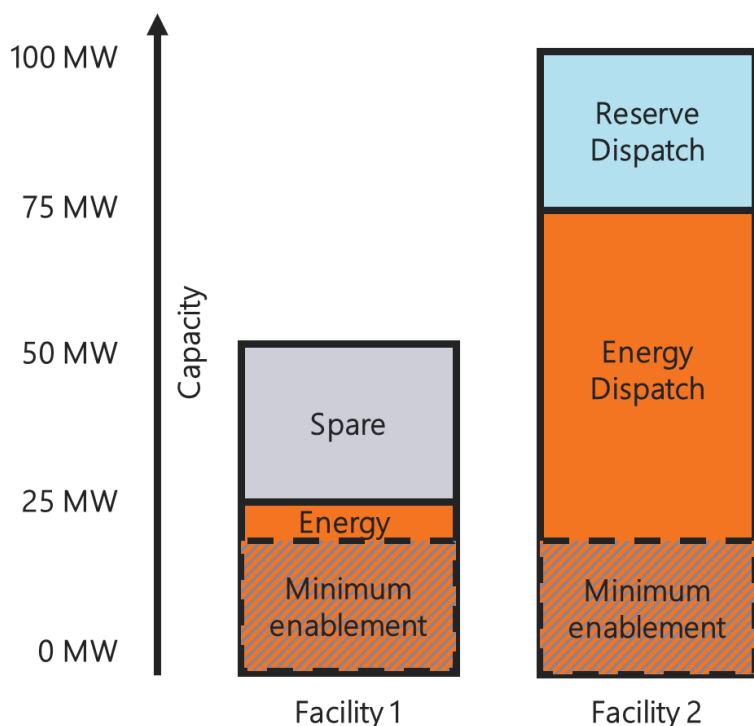
Outputs

Dispatch

Both Facilities must be cleared for at least 20 MW of energy. Again, the cheapest way to meet the energy demand is to dispatch Facility 2 for as much energy as possible, and then dispatch Facility 1 for the remainder. However, while the 25 MW reserve requirement can be met by either Facility, it is cheaper to have Facility 2 provide it by backing off and having Facility 1 fill the energy gap (a cost of $\$500 - \$100 = \$400$) than to have Facility 1 provide it (at an offered price of $\$1,600$).

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

Figure 33 Co-optimisation Example 4c dispatch



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

$$\text{TotalCost} = 25 \times \$500 + 75 \times \$100 + 0 \times \$1600 + 25 \times \$0 = \$20,000$$

Marginal prices

The marginal prices are based on the additional cost of serving another increment of the service. Facility 1 is now the marginal Facility for energy. Facility 2 is the marginal Facility for reserve.

- *Energy*: If demand increased by 1 MW (to 101 MW), Facility 1 would be dispatched for one more MW, and the total cost would rise by \$500.

$$\text{TotalCost} = 26 \times \$500 + 75 \times \$100 + 0 \times \$1600 + 25 \times \$0 = \$20,500$$

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 would be backed off by 1 MW energy to make room. That unit of energy would instead be provided by Facility 1 (at a cost of \$500 instead of \$100).

$$\text{TotalCost} = 26 \times \$500 + 74 \times \$100 + 0 \times \$1600 + 26 \times \$0 = \$20,400$$

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

The shadow prices on the minimum enablement constraints are zero, because both Facilities are efficiently dispatched above the limit and dispatch would not change with an increment to the minimum enablement limit.

Payments

Facility 1 revenue is $25 \text{ MW} \times \$500 + 0 \text{ MW} \times \$1600 = \$12,500$

Facility 1 costs are $25 \text{ MW} \times \$500 + 0 \text{ MW} \times \$0 = \$12,500$

Facility 1 profit is $\$12,500 - \$12,500 = \$0$

Facility 2 revenue is $75 \text{ MW} \times \$500 + 25 \text{ MW} \times \$400 = \$47,500$

Facility 2 costs are $75 \text{ MW} \times \$100 + 25 \text{ MW} \times \$0 = \$7,500$

Facility 2 profit is $\$47,500 - \$7,500 = \$40,000$

Facility 1 is no longer losing money to provide energy.

In practice, Facility 1's reserve offer has overcompensated for enablement losses. Dispatch, pricing, and payment outcomes would all be the same for Facility 1 reserve offers of *more than* \$400.

Example 4d explores what happens if Facility 1 makes a reserve offer less than \$400.

A2.6 Example 4d: Reserve offer price including enablement losses is dispatched.

In this example, Facility 1 adjusts its reserve offer to account for enablement losses in the energy market, but at a level that does not change its position in the reserve merit order.

Inputs

Facility 1 notes the interaction with Facility 2 offers and adjusts its reserve offer to be lower than the expected reserve price.

System parameters		Facility 1 parameters		Facility 2 parameters			
		Price (\$/MW)	Quantity (MW)	Price (\$/MW)	Quantity (MW)		
Energy demand	100 MW						
Reserve requirement	25 MW						
		Maximum capacity	50 MW	Maximum capacity	100 MW		
		Minimum enablement	20 MW	Minimum enablement	20 MW		
		Energy offer	500	50	Energy offer	100	100
		Reserve offer	320	30	Reserve offer	0	80

Optimisation problem

The optimisation problem is the same as for Example 3a. Both Facilities have minimum enablement limit constraints.

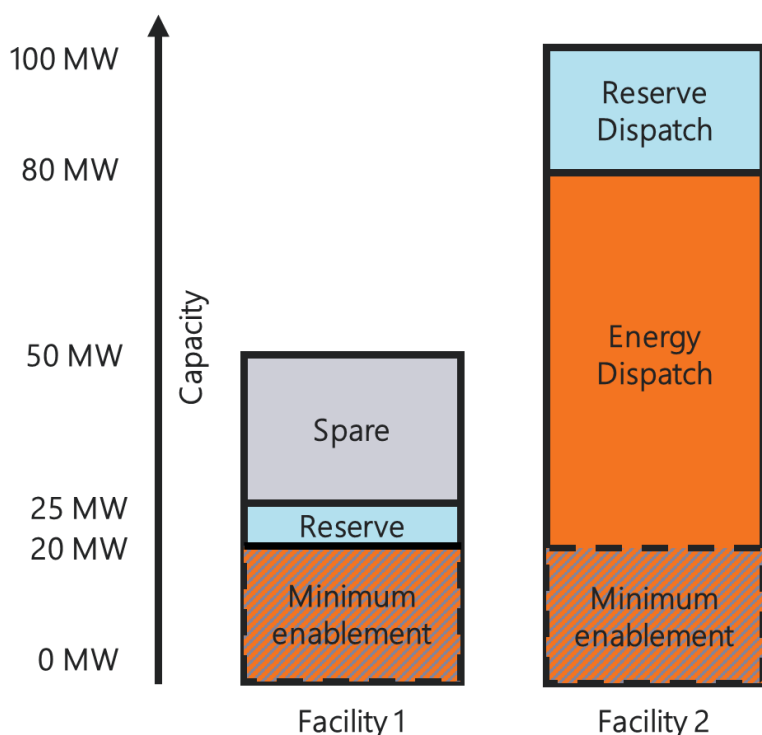
Outputs

Dispatch

Both Facilities must be cleared for at least 20 MW of energy. Again, the cheapest way to meet the energy demand is to dispatch Facility 2 for as much energy as possible. Facility 2 still has 20 MW of headroom, and there is no cost to using this for reserve. Compared to Example 4c, it is now cheaper to have Facility 1 provide the last 5 MW of reserve than to back off Facility 2.

- Facility 1 Energy dispatch: 20 MW reserve dispatch: 5 MW.
- Facility 2 Energy dispatch: 80 MW reserve dispatch: 20 MW.

Figure 34 Co-optimisation Example 4d dispatch



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

$$\text{TotalCost} = 20 \times \$500 + 80 \times \$100 + 5 \times \$320 + 20 \times \$0 = \$19,600$$

Marginal prices

The marginal prices are based on the additional cost of serving another increment of the service. Facility 1 is now the marginal Facility for reserve, and its reserve cost contributes to the market clearing price for energy.

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

$$\text{TotalCost} = 20 \times \$500 + 81 \times \$100 + 6 \times \$320 + 19 \times \$0 = \$20,020$$

The change in total costs would be \$420, 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.

$$\text{TotalCost} = 20 \times \$500 + 80 \times \$100 + 6 \times \$320 + 20 \times \$0 = \$19,920$$

The change in total costs would be \$320/MW, so this is the marginal price for reserve.

Facility 1's minimum enablement constraint is binding, so it has a shadow price, which still does not flow through into the energy or reserve prices (which is why Facility 1 has increased its reserve offer).

- *Minimum enablement 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. Facility 2 would back off for energy but would be able to provide 1 MW more of reserve.

$$\text{TotalCost} = 21 \times \$500 + 79 \times \$100 + 4 \times \$320 + 21 \times \$0 = \$19,680$$

The change in total costs would be \$80/MW, and this is the shadow price on the minimum enablement constraint for Facility 1.

- The minimum enablement constraint for Facility 2 is not binding so the shadow price is \$0.

Payments

Facility 1 revenue is $20 \text{ MW} \times \$420 + 5 \text{ MW} \times \$320 = \$10,000$

Facility 1 costs are $20 \text{ MW} \times \$500 + 5 \text{ MW} \times \$0 = \$10,000$ (Facility 1 variable costs to provide reserve are still zero, though the offer is \$320 to account for energy market losses)

Facility 1 profit is $\$10,000 - \$10,000 = \$0$

Facility 2 revenue is $80 \text{ MW} \times \$420 + 20 \text{ MW} \times \$320 = \$40,000$

Facility 2 costs are $80 \text{ MW} \times \$100 + 20 \text{ MW} \times \$0 = \$8,000$

Facility 2 profit is $\$40,000 - \$8,000 = \$32,000$

Facility 1 is now breaking even, because the energy and reserve prices have increased. If Facility 1 offered less than \$320 per unit of reserve, it would lose money.

In practice, Facility 1 could offer anywhere between \$320 and \$400 per unit of reserve, and still be marginal for reserve. It has market power and could push up the reserve and energy prices in a way that recovers more than its variable costs.

The fact that \$320 appears as the breakeven point in Example 3b and Example 4d is because in both cases, the enablement losses are recovered across 25 MW of service. In Example 3b, they are recovered over 25 MW of reserve provision, while in Example 4d, they are recovered over 20 MW of energy and 5 MW of reserve. Examples 5a and 5b show what happens if the enablement losses are recovered over a different quantity of service.

A2.7 Example 5a: Reserve price is zero with enablement limits

Examples 5a and 5b are the same as examples 4a and 4d, 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		Facility 1 parameters			Facility 2 parameters		
			Price (\$/MW)	Quantity (MW)		Price (\$/MW)	Quantity (MW)
Energy demand	100 MW	Energy offer	500	50	Energy offer	100	95
Reserve requirement	25 MW	Reserve offer	0	30	Reserve offer	0	75
		Maximum capacity		50 MW	Maximum capacity		95 MW
		Minimum enablement		20 MW	Minimum enablement		20 MW

Optimisation problem

The optimisation problem is the same as for Example 4a.

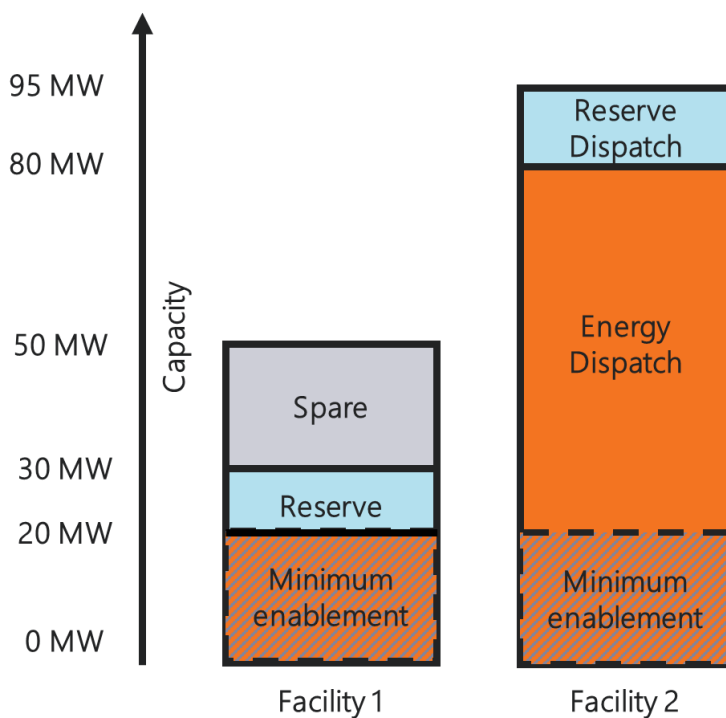
Outputs

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 35 Co-optimisation Example 5a dispatch



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

$$\text{TotalCost} = 20 \times \$500 + 80 \times \$100 + 10 \times \$0 + 15 \times \$0 = \$18,000$$

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.

$$\text{TotalCost} = 20 \times \$500 + 81 \times \$100 + 11 \times \$0 + 14 \times \$0 = \$18,100$$

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.

$$\text{TotalCost} = 20 \times \$500 + 80 \times \$100 + 11 \times \$0 + 10 \times \$0 = \$18,000$$

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:

- Minimum enablement 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)

$$\text{TotalCost} = 21 \times \$500 + 79 \times \$100 + 10 \times \$0 + 15 \times \$0 = \$20,400$$

The change in total costs would be \$400, and this is the shadow price on the minimum enablement constraint for Facility 1.

- Minimum enablement at Facility 2: If the enablement limit increased by 1 MW (to 21 MW), dispatch would not change, because the constraint is not binding.

$$\text{TotalCost} = 20 \times \$500 + 80 \times \$100 + 15 \times \$0 + 10 \times \$0 = \$20,000$$

The total cost would stay the same, so the shadow price on the minimum enablement constraint for Facility 2 is 0.

Payments

Facility 1 revenue is $20 \text{ MW} \times \$100 + 10 \text{ MW} \times \$0 = \$2,000$

Facility 1 costs are $20 \text{ MW} \times \$500 + 10 \text{ MW} \times \$0 = \$10,000$

Facility 1 profit is $\$2,000 - \$10,000 = -\$8,000$

Facility 2 revenue is $80 \text{ MW} \times \$100 + 15 \text{ MW} \times \$0 = \$8,000$

Facility 2 costs are $80 \text{ MW} \times \$100 + 15 \text{ MW} \times \$0 = \$8,000$

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.

Facility 1 has two options.

1. Remove its reserve offers altogether, so it is not dispatched for reserve. The outcome would be as in Example 4b.
2. Increase its reserve offer price to account for the 'enablement losses' in the energy market.
 - a. If dividing enablement losses by the Example 5a dispatch, it would offer \$800, and the outcome would be to back off Facility 2 as in Example 4c.
 - b. What happens in the equivalent to Example 4d? See Example 5b below.

A2.8 Example 5b: Reserve offer price including enablement losses is dispatched.

In this example, Facility 1 adjusts its reserve offer to account for enablement losses in the energy market at a level that allows it to just recover those costs.

Inputs

Facility 1 notes the interaction with Facility 2 offers, and adjusts its reserve offer to be lower than the expected reserve price.

System parameters		Facility 1 parameters			Facility 2 parameters		
			Price (\$/MW)	Quantity (MW)		Price (\$/MW)	Quantity (MW)
Energy demand	100 MW	Maximum capacity	50 MW	Maximum capacity	95 MW	Minimum enablement	20 MW
Reserve requirement	25 MW	Minimum enablement	20 MW	Minimum enablement	20 MW	Energy offer	100
		Energy offer	500	Quantity (MW)	50	Reserve offer	0
		Reserve offer	266.67	Quantity (MW)	30	Reserve offer	75

Optimisation problem

The optimisation problem is the same as for Example 4a.

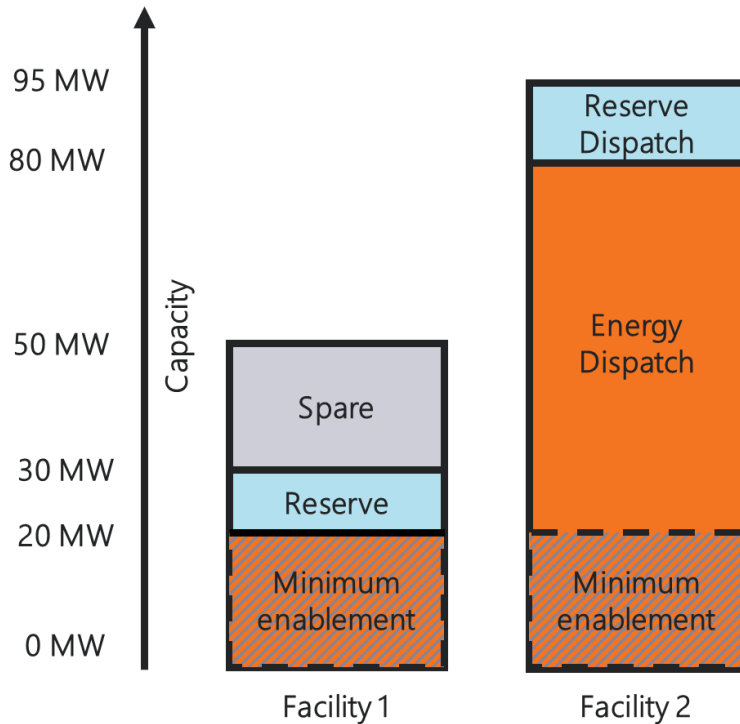
Outputs

Dispatch

Both facilities must be cleared for at least 20 MW of energy. Again, the cheapest way to meet the energy demand is to dispatch Facility 2 for as much energy as possible. Facility 2 still has 15 MW of headroom, and there is no cost to using this for reserve. It is cheaper to have Facility 1 provide the last 10 MW of reserve than to back off Facility 2.

- Facility 1 Energy dispatch: 20 MW reserve dispatch: 10 MW.
- Facility 2 Energy dispatch: 80 MW reserve dispatch: 15 MW.

Figure 36 Co-optimisation Example 5b dispatch



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

$$\text{TotalCost} = 20 \times \$500 + 80 \times \$100 + 10 \times \$266.67 + 15 \times \$0 = \$20,666.70$$

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 be dispatched for one more MW, and Facility 1 would provide one more unit of reserve.

$$\text{TotalCost} = 20 \times \$500 + 81 \times \$100 + 11 \times \$266.67 + 14 \times \$0 = \$21,033.37$$

The change in total costs would be \$366.67, 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.

$$\text{TotalCost} = 20 \times \$500 + 80 \times \$100 + 11 \times \$266.67 + 10 \times \$0 = \$20,933.37$$

The change in total costs would be \$266.67/MW, so this is the marginal price for reserve.

Facility 1's minimum enablement constraint is binding, so it has a shadow price, which still does not flow through into the energy or reserve prices (which is why Facility 1 has increased its reserve offer).

- *Minimum enablement 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. Facility 2 would back off for energy but would be able to provide 1 MW more of reserve.

$$\text{TotalCost} = 21 \times \$500 + 79 \times \$100 + 9 \times \$266.67 + 16 \times \$0 = \$20,800.03$$

The change in total costs would be \$133.33/MW, and this is the shadow price on the minimum enablement constraint for Facility 1.

- *The minimum enablement constraint for Facility 2 is not binding so the shadow price is \$0.*

Payments

Facility 1 revenue is $20 \text{ MW} \times \$366.67 + 10 \text{ MW} \times \$266.67 = \$10,000.10$

Facility 1 costs are $20 \text{ MW} \times \$500 + 5 \text{ MW} \times \$0 = \$10,000$ (Facility 1 variable costs to provide reserve are still zero, though the offer is $\$266.67$ to account for energy market losses)

Facility 1 profit is $\$10,000.10 - \$10,000 = \$0.10$

Facility 2 revenue is $80 \text{ MW} \times \$366.67 + 15 \text{ MW} \times \$266.67 = \$33,333.65$

Facility 2 costs are $80 \text{ MW} \times \$100 + 15 \text{ MW} \times \$0 = \$8,000$

Facility 2 profit is $\$33,333.65 - \$8,000 = \$25,333.65$

Facility 1 is the marginal Facility for reserve, and its reserve cost contributes to the market clearing price for energy. If it offered less than $\$266.67$ per unit of reserve, it would lose money.

In practice, Facility 1 could offer anywhere between $\$266.67$ and $\$400$ per unit of reserve, and still be marginal for reserve. It has market power and could push up the reserve and energy prices in a way that recovers more than its variable costs.

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
ERA	Economic Regulation Authority
ESS	Essential System Services
FCESS	Frequency Co-optimised Essential System Services
FOS	Frequency Operating 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

Term	Definition
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
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
WEM	Wholesale Electricity Market
WEM Procedure owners	AEMO, the Coordinator of Energy, the Network Operator, and the ERA