Operating Reserve Design

November 2022

Technical advice

A report to support rule determination by the AEMC

Important notice

Purpose

The Energy Security Board (ESB) P2025 Program recommended an Operating Reserve market be considered through two industry-led AEMC rule change requests (ERC0295 and ERC0307). Both rule changes seek to address the increasing need for energy reserves as the power system transforms.

In November 2021, AEMC extended the time for draft determination on these requests to 30 June 2023 to allow for:

- data to be gathered from the provision of reserves from under the recently implemented five-minute financial settlement and wholesale demand response market,
- further information on the ESB's progression of post 2025 reforms relating to a capacity mechanism and jurisdictional strategic reserve mechanism, and
- AEMO to prepare this detailed technical advice.

A specific request was sent by AEMC Commissioners to AEMO on 23 Dec 2021 to provide key advice on:

1. The development of an operating reserve demand curve
2. The implementation of a causer pays cost recovery mechanism for the market
3. The reserves obligation and interaction with dispatch and other processes
4. The direct implementation costs and proposed timing of an Operating Reserve market.

This report provides this technical advice.

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Version control

Version	Release date	Changes
#1	11/11/2022	

Executive summary

AEMO was requested by the Australian Energy Market Commission (AEMC) to provide advice on key design elements of an Operating Reserve service to support consideration of two rule change requests and the Energy Security Board (ESB) Post-2025 recommendations.

Problem statement

Operating reserve is defined as the capability to respond to large continuing changes in energy requirements.[1]

Forecast uncertainty is expected to increase in the future (2025+) power system, contributed to by factors including growing variable renewable energy (VRE) penetrations, weather, participant availability, commitment decisions, storage depth, and coordination of distributed energy resources[2]. To maintain sufficient operating reserves to meet security and reliability obligations, AEMO may be forced to regularly intervene and activate the Reliability and Emergency Reserve Trader (RERT).

Demand and supply of operating reserve in the NEM

Minimum levels of operating reserve are required for the system operator to maintain system security and reliability. Operating reserve, or ‘headroom’, can be measured in pre-dispatch and other systems as offers of energy above forecast demand. If the supply-demand balance tightens compared to its forecast, operating reserves can be dispatched as energy. This paper considers operating reserves as headroom that can be utilised over time horizons beyond a single dispatch interval.

To date, operating reserves have been provided in the National Electricity Market (NEM) from incentives in the energy spot market, participant positioning to manage individual financial risks, and as a by-product of the technologies comprising the generation fleet.

AEMO is already witnessing increased variability, uncertainty and lack of headroom, and an asymmetry of risk between participants and the system operator in carrying out its role in meeting security and reliability requirements during times of high forecast uncertainty. The nature, timing and visibility of reserves being provided is dramatically changing and the uncertainty of its provision is increasing. Whilst several market reforms are underway to facilitate greater renewable penetration, including the Operational Security Mechanism and frequency response reforms, none address the specific need for operating reserves. Commercial rebidding practices prior to dispatch are reducing confidence in pre-dispatch forecasts of energy spot market availability. It is difficult to predict whether the fleet and market will supply sufficient capability to respond to large continuing changes in energy requirements to avoid frequent AEMO intervention in the future. It is further unclear if the contract market will continue to drive commitment of resources, and in turn mitigate risk for the system operator at times of forecast uncertainty.

There are several approaches to securing reserve varying with the timescale of provision and the manner of procurement. A capacity mechanism can procure energy availability over a timeframe of years, strategic or emergency reserves may be procured through forward contracts (days to years), and an operating reserve market can procure availability in operational timeframes (minutes to hours).

[1] AEMO Power System Requirements, Reference Paper July 2020.

[2] AEMO Engineering Framework 2022, AEMO Integrated System Plan 2022, AEMO Renewable Integration Study 2020

A market for valuing operating reserves in the NEM

The objective of an Operating Reserve market is to reduce the need for out-of-market intervention due to lack of reserves in operational timeframes. An Operating Reserve market would unbundle the pricing of reserves from energy to separately value flexible and responsive resources, and in doing so provide an explicit signal for their provision in-market. A new reserve services market would aim to:

- Provide a signal for Type 1 and 2 Reliability and Emergency Reserve Trader (RERT) service providers (activation times less than 30 min) to participate in-market instead of through manually administered out-of-market contracts
- Reduce instances of intervention and some of the associated costs for lack of reserve (including procurement and activation of RERT)
- Signal a scarcity of reserves across the operational horizon, and bring reserves online to respond to unexpected changes in net demand, even if energy prices are low and/or uncertain
- Support participation of demand side resources as scheduled resources in wholesale markets
- Incentivise investment in flexible dispatchable resources, and reward resources that provide reserves to the market

The winter crisis of 2022 (including the suspension of the market in June) highlighted the many and varied challenges facing the NEM associated with resource adequacy, capacity availability, energy constraints, forecasting and unit commitment. The event involved a confluence of high commodity prices, domestic energy market price caps, planned and unplanned outages of scheduled generating plant, fuel constraints, very low output from semi-scheduled generation and high winter demand. AEMO notes that an Operating Reserve market would have been unlikely to address any of these challenges.

The winter crisis further highlighted the uncertainty that accompanies pre-dispatch forecasts for the energy spot market due to commercial rebidding, and AEMO notes that pre-dispatch offers of Operating Reserve will also have attendant uncertainty. Without robust and enforceable compliance mechanisms, this inherited uncertainty of pre-dispatch availability would counteract the objective of the new market to avoid intervention that may be required to maintain system security and reliability. Market signals and high prices have not always yielded expected responses from market participants, most recently witnessed during the winter crisis.

This advice focuses primarily on the specific challenge of maintaining sufficient operating reserves to manage increased forecast uncertainty in the power system, but we also include an assessment of the ability of an Operating Reserve market to address other operational challenges, with a comparison against alternative mechanisms including contracts for reserves and ahead markets.

International Operating Reserve markets

Operating Reserve markets are commonplace around the world and often operate alongside a capacity mechanism. There is an emerging recognition of the explicit valuation of reserves instead of solely relying on spot-pricing as electricity systems transition to greater penetration of renewables.

Some reflections on the Texas market's recent performance are summarised:

> *"The stark divergence in outcomes reflects severely misaligned incentives, reinforcing that successful reforms will focus on the allocation and sharing of risk… merely relying on refinements to spot pricing or improved modeling of correlated failures will not solve this fundamental issue." Mays et al, 2022, Private risk and social resilience in liberalized electricity markets, Joule 6, (1).*

And in Europe:

> *"The absence of a real-time market for reserve capacity, i.e. a market for settling reserve imbalances in real time, is a serious handicap of the European electricity market towards achieving this transition… Scarcity pricing emerges as a no-regret measure in this respect. The mechanism only becomes active when the system is under stress, and works towards relieving this stress." A. Papavisilou, 2020, Scarcity pricing and the missing European market for real-time reserve capacity. The Electricity Journal (33), 10.*

To note, Operating Reserve markets regularly exist alongside capacity markets (including ISO-NE, PJM, NYISO, CAISO, Ontario, UK, Mexico, and EirGrid), where there is recognition that the provision of capacity to meet peak demand has different value to the provision of flexible capacity at times of low reserve or forecast uncertainty.

An Operating Reserves market

A working model of a 30-minute co-optimised Operating Reserve market was provided by AEMC to support AEMO's advice and was designed in consultation with the market bodies and industry stakeholders.

AEMO notes that the appropriate 'ahead-ness' of procurement of an Operating Reserve market requires detailed consideration alongside the nature of reserve obligation and interaction with intervention frameworks currently under redevelopment. For an Operating Reserve market that procures "additional-availability-in-ahead-timeframes" (as per the working model) there are trade-offs between i) participant management of future availability and price risks, and ii) system operator visibility of availability and opportunity to intervene if required. A further key timeframe is that of market activation and associated visibility and confidence in pre-dispatch ahead of periods of significant forecast uncertainty.

Following detailed consideration of interaction with dispatch processes, and only if strict compliance measures were in place, AEMO's preference would be for a 1-4 hour Operating Reserve mechanism that allows manual intervention to ensure adequate reserves if required. The earlier scheduling of resources would provide greater confidence in future delivery of energy in timeframes relevant to intervention decisions, and additional ability to increase availability to bring units online. That is, longer ahead timeframes support certainty of availability without having to rely on out-of-market interventions (such as RERT). In contrast, under a 30-minute product, intervention decisions must be made entirely on the basis of expectations of participant behaviour and confidence in pre-dispatch forecasts.

AEMO acknowledges that intervention decision timing varies according to the resources available through RERT and via directions, and so even a 4-hour product is not necessarily sufficient to cover all scenarios. We also acknowledge there are potential costs and risks of a longer (i.e., >4 hr) timeframe product under this working model. AEMO therefore believes there is merit in considering other product models that could firmly commit resources to ensure adequate reserves over the operational horizon more broadly.

AEMO has proceeded with design in this report based on the working model of a 30-minute ahead product.

Operating Reserve Demand Curve

Informed by the ESB process and from external advice and stakeholder consultation AEMO identified several options for the construction of an operating reserve demand curve as requested by AEMC. Key market design principles include close interaction with the value of customer reliability and AEMO's intervention framework, in particular, RERT. An Operating Reserve market should be an efficient mechanism to procure sufficient reserves to avoid AEMO intervention at prices that reflect the value of customer reliability.

AEMO recommends, as a starting point for future development, a hybrid approach with robust compliance that considers the value of customer reliability and integrates with existing intervention frameworks (example in Figure 1) though we note that any mechanism and pricing structure should be developed further through consultation with stakeholders.

The example curve reflects the stepwise values placed on different reserve levels according to the current intervention framework:

1. Minimum reserve requirements to avoid lost load (currently the Lack of Reserve (LOR) 3 threshold for load-shedding when reserve capacity is at or below zero). This level of operating reserve could theoretically reference the value of customer reliability (VCR) or a similar reflective figure, less the maximum price cap (MPC) which participants would receive in the energy market if reserves were to fall below zero. In practice, placing this value at MPC may provide a more consistent approach for implementation alongside the existing spot markets.
2. Incentive price to bring reserves into the market, referencing the existing LOR2 threshold when reserve capacity falls below the size of the largest credible risk.
3. Uncertainty pricing constructed via the probability curve of lost load (for example through historical operational demand uncertainty), reflecting the incremental value of avoiding out-of-market actions for higher reserve levels and allowing the procurement of additional reserve to appropriately manage system risk above minimum requirements when efficient to do so.
4. Operating reserve prices equal to zero when there is ample provision.

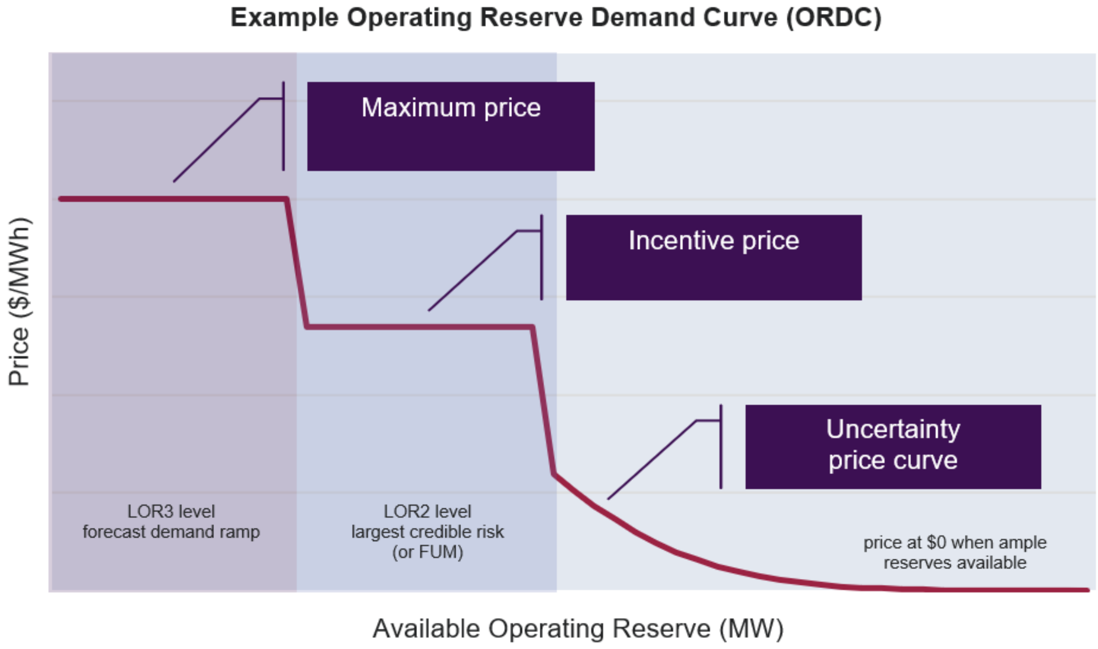


Figure 1 An example stepped ORDC for the NEM reflecting the intervention framework and a curve to reflect the incremental value of avoiding out-of-market actions according to uncertainty and the probability of lost load.

The Operating Reserve market price and quantity is set by the intersection of the supply curve (the offer stack) with the demand curve. When there is ample reserve available (to the right of the diagram), the supply curve would intersect with the demand curve at $0, and hence the price of operating reserve would be zero. This calculation of offers of reserve may include energy spot-market offers in pre-dispatch above forecast demand with care taken to avoid double counting. Offers into the Operating Reserve market would be incorporated into the Short- Term Projected Assessment of System Adequacy (ST-PASA) and, in turn, the forecast for reserves. The aim of an operating reserve mechanism is to minimise out-of-market actions for forecast lack-of-reserve conditions (such as the procurement and activation of RERT when there is a forecast LOR2). AEMO recommends that the methodology and curve parameters be detailed in a Procedure that allows periodic review and consultation with stakeholders.

AEMO is currently conducting a comprehensive review of the pre-dispatch PASA and ST PASA methodology in its ST PASA replacement project. This project includes the calculation of uncertainty margins which may provide a more direct and dynamic representation of reserve requirements based on a more complete and up-to-date consideration of power system risk from demand, supply and network conditions. Any Operating Reserve market would need to interact closely with the redeveloped ST PASA framework; the construction of an operating reserve demand curve may use the calculated uncertainty margins as a natural input, discussed further in the report.

AEMO notes the Operating Reserve market and demand curve is most suited to situations where the system operator is able to identify periods of uncertainty ahead; unpredictable tail risks will remain challenging, including those considered by General Power System Security Risk Review.

Interaction with dispatch processes

Interactions between operating reserve and dispatch processes and the intervention framework require careful consideration. There are several factors that make an operating reserve especially complex including the 'ahead-ness' of procurement, the nature of co-optimisation, integration into pre-dispatch and the NEM Dispatch Engine (NEMDE). Detailed design should investigate possible unintended consequences from placing a price on operating reserves which have been offered to date without being explicitly valued. Unintended consequences may also arise following dispatch of OR through unexpected charging from storage resources to manage future availability.

A benefit of an Operating Reserve market is identified as reduced instances of AEMO intervention for low reserves with reduced RERT and associated intervention costs as the market transitions towards greater penetration of renewables, noting these costs may contribute to 'trigger' metrics for identification of when an Operating Reserve market should be implemented.

A hypothetical scenario may help highlight how an operating reserve would work in practice whilst retaining RERT (Figure 2). During low reserve conditions an Operating Reserve market would help bring reserves online, avoiding the need for declaration of actual LOR2 conditions with associated intervention costs. If sufficient reserves do not materialise, RERT may still be activated, though costs would need to be considered in relation to the value of customer reliability.

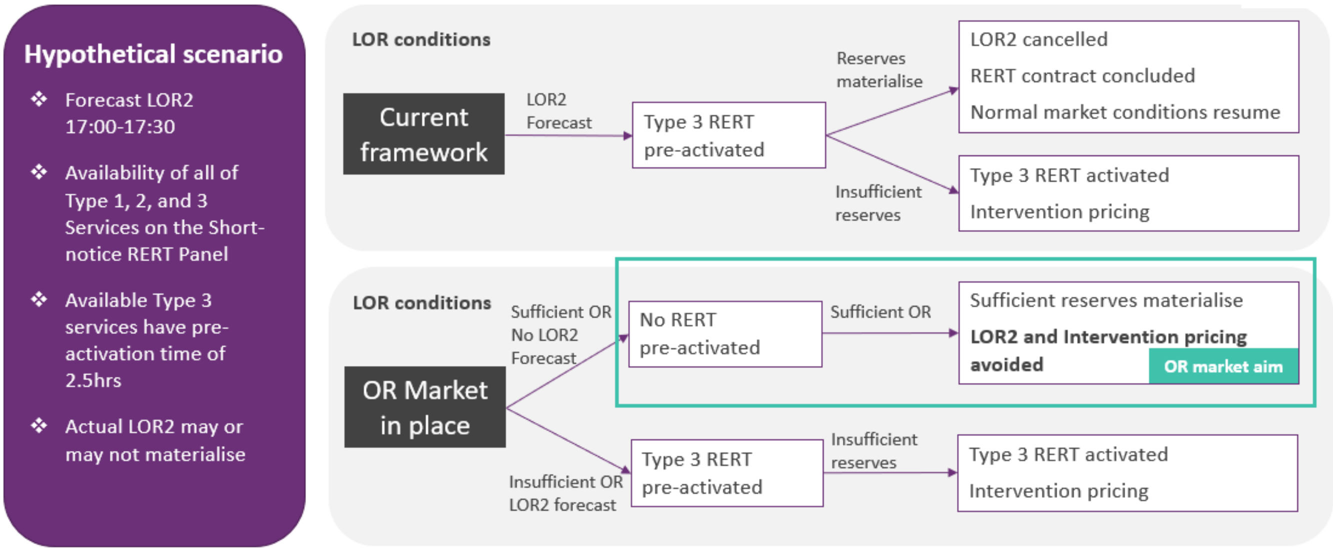


Figure 2 Hypothetical scenario outlining how an Operating Reserve market can help avoid AEMO intervention and RERT costs, whilst retaining the ability to engage RERT if reserves fail to materialise.

In addition to interaction with the intervention framework, there are several other critical design options to consider.

Obligation

A critical design consideration is the nature of the obligation and associated compliance for the scheduling of an offer to provide operating reserve. The strength of compliance enforcement and rules regarding commercial rebidding will ultimately determine operator confidence that i) OR offered in pre-dispatch will remain available, and

ii) that cleared OR will be physically available in the ahead time-frame. That is, the strength of compliance and confidence of provision is fundamentally important for any market to be able to avoid operator intervention.

The nature of reserves being dispatched ahead of a dispatch interval creates risks that changing system conditions, in particular network constraints, between dispatch and delivery might impact the ability or need for reserves to be delivered. Similarly, the obligations on participants should not limit participation in other markets where of greater value to the system. Two options for this obligation include i) penalty for non-delivery and ii) payment only for delivery, summarised below with advantages and disadvantages.

Table 1 Advantages and disadvantages of the two options for the obligation on an offer of operating reserve.

Obligation option	Advantages	Disadvantages
1. Penalty for non-delivery (cleared OR must be offered as energy in the dispatch interval 30min ahead, penalty for non-delivery)	Provides greatest certainty to the system operator that availability will materialise. Supports confidence for the operator to avoid declaration of LOR conditions.	Difficult to assess non-compliance in the event of circumstances (e.g., constraints) beyond a participant's control. Participants carry the risks of uncertain energy market dynamics in the subsequent 30 minutes. System operator may need to consider ramping or dispatch interactions in the intervening time-interval between offer and energy dispatch.
2. Payment only for delivery (no penalties) (cleared OR paid only if offered in the dispatch interval 30min ahead, no payment (nor penalty) if offer fails to materialise)	Provides greater simplicity of compliance. Allows participants to manage their own risks if dispatch considerations change in the intervening time-interval to make the OR offer uncommercial to materialise.	Requires system operator consideration of the uncertainty regarding whether offered reserves will materialise. System operator carries the risk of uncertain energy market dynamics in the intervening 30 minutes. Additional OR may need to be procured to a level that supports confidence to avoid declaration of LOR conditions

Ramping capability can be additionally factored into the dispatch of operating reserve, alongside various hybrid options of compliance, including through a variable penalty factor which may penalise failure to provide reserves where reserves are low. These options are explored in further detail in the report.

AEMO's preference is for "penalty for non-delivery" with robust compliance frameworks in place. AEMO's further preference is that market design remains consistent with existing compliance arrangements where possible, with contingency FCAS compliance providing a starting point for development, noting any possible arrangements require further consideration and consultation with stakeholders and the Australian Energy Regulator.

Activation

There are several options for when an Operating Reserve market may be activated:

i) only during actual or forecast lack of reserve conditions

ii) for selected days (e.g., identified a day ahead)

iii) always on

AEMO has proceeded with an ‘always on’ assumption for market design, though notes there are cost, participation and market behaviour implications to explore. If the ORDC price is set to zero when ample reserves are available, this may be implicitly equivalent to market activation only during times of forecast low reserve. Activation only during low reserve conditions or during identified days-ahead supports reduced cost, avoids market power issues when reserves are not scarce, and more closely reflects the principles of scarcity pricing. LOR activation may also be an appropriate pathway for market testing and implementation, if not as an enduring design feature. Trade-offs for short-duration market activation include challenges in constructing financial products around an Operating Reserve market, adjusted incentives for market participation, and unintended consequences.

Participation

All scheduled and semi-scheduled resources are envisaged to be eligible providers of operating reserve, including demand response, Virtual Power Plants (VPP), batteries, pumped hydro storage, and variable renewable energy resources (VRE). Curtailed VRE may be particularly suited to providing operating reserve if curtailed for financial reasons at times of negative prices. Scheduled bidirectional units (such as batteries or VPPs) may provide operating reserve across the full range of dispatch capability from maximum load to maximum generation, and scheduled loads that have price-responsive capacity may provide operating reserve through this capacity up to their inflexible consumption requirements. This may particularly suit aggregated coordination of price-responsive demand response resources.

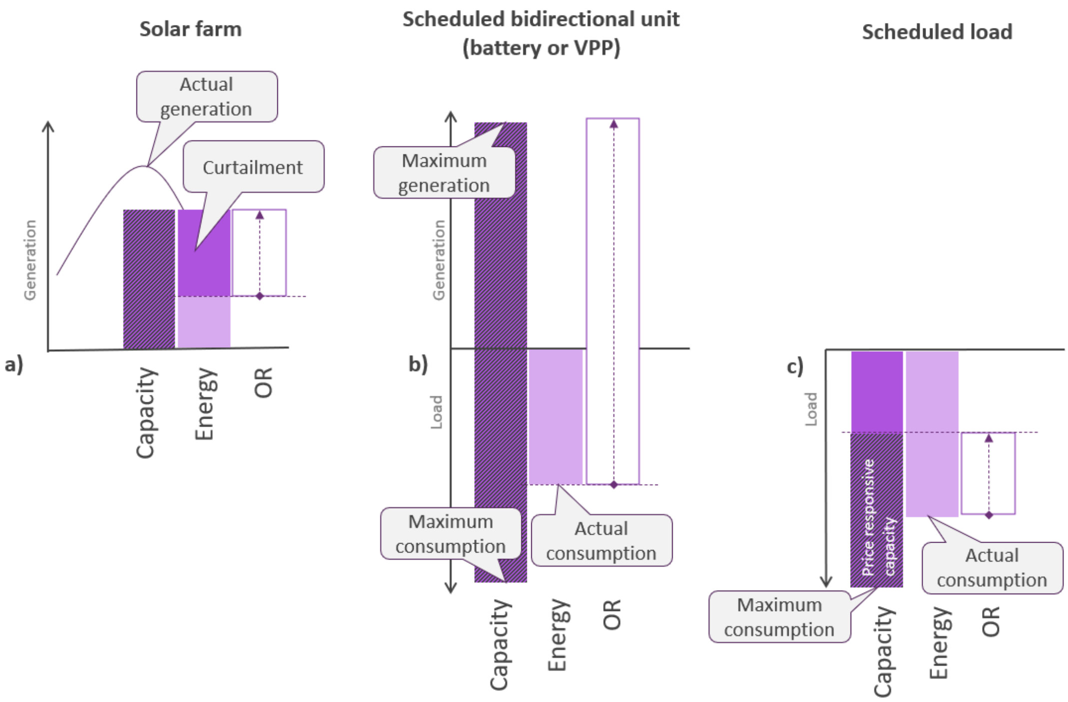


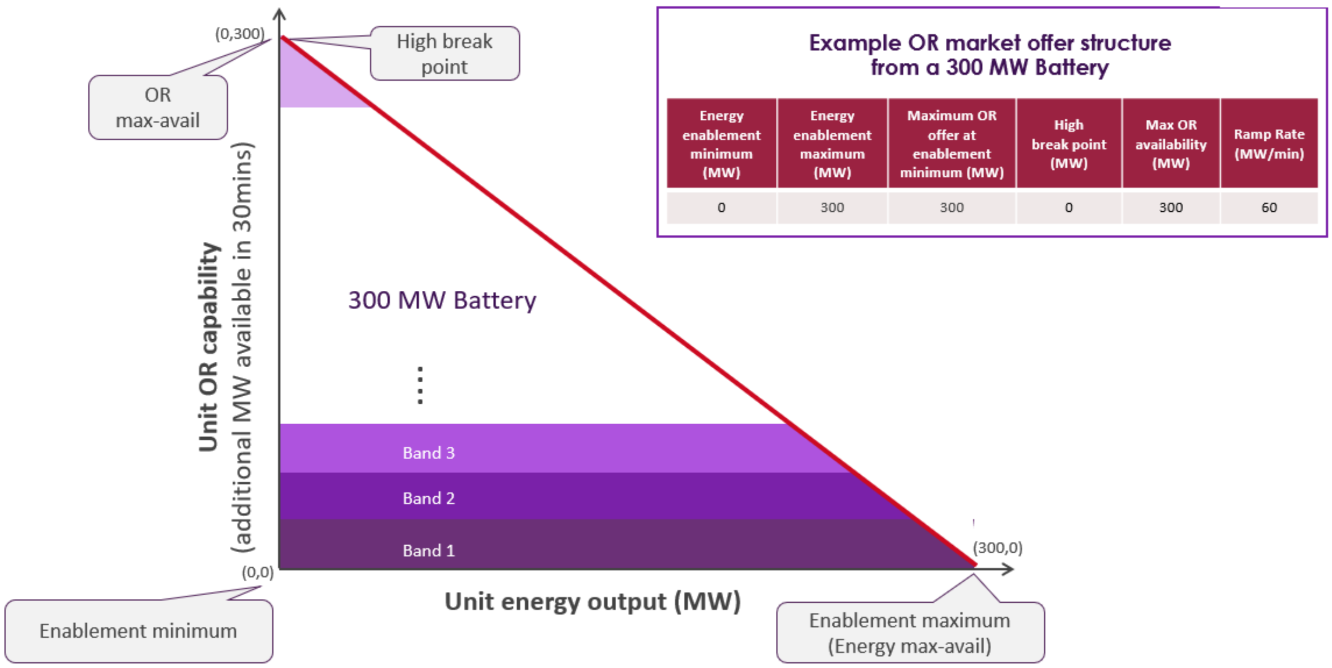
Figure 3 Operating Reserve may be provided by VRE e.g., a curtailed solar farm (a), scheduled bidirectional units e.g., a battery or virtual power plant (VPP) (b), or scheduled loads with price responsive capacity (c).

Scheduling

There are several options for how operating reserve may be offered, scheduled and co-optimised with other wholesale markets. For offers, AEMO's recommendation is that (price, quantity) pairs to supply Operating Reserve be offered, aligning with offer structures for energy and FCAS market designs. Settlement would be ex-post, though there are some important relationships between scheduling and the consequences for non-delivery that require careful consideration.

The design should allow all scheduled and semi-scheduled resources to participate, but further consideration is required for participation by scheduled loads.

Co-optimisation requires detailed consideration given the inter-temporal nature of operating reserve, and the direct interrelationship with energy offers and dispatch in both the current dispatch interval and the interval 30 minutes ahead. A trapezium for Operating Reserve offers may be constructed similarly to the FCAS-energy trapezium, with an example for a battery included below (Figure 3) with an assumed capability to ramp to maximum availability within a dispatch interval.



Energy enablement minimum (MW)	Energy enablement maximum (MW)	Maximum OR offer at enablement minimum (MW)	High break point (MW)	Max OR availability (MW)	Ramp Rate (MW/min)
0	300	300	0	300	60

Figure 4 An indicative co-optimisation trapezium (or more accurately a triangle) for a 300MW battery with ability to ramp to maximum availability within a dispatch interval.

This trapezium (or more accurately a triangle) is perhaps the simplest example given the assumed rapid ramp rate of the example battery. Further investigation is required for how trapezia may be constructed for plant with relatively slow ramp rates and how ramp rates would be considered during scheduling. Further detailed design is also required on the nature of co-optimisation between operating reserve, slow raise frequency control ancillary services, and interconnection.

Contracting for OR

An extension of the approach to selectively activate the Operating Reserve market could be to implement bespoke contracting arrangements for resources to maintain headroom during periods of high forecast uncertainty and/or projected reserve shortfalls. This service could allow in-market resources to participate and may support the supply of reserves from a broader range of participants (including demand response and VPPs), as well as providing a mechanism for the commitment of necessary reserves across the short-term operational horizon. Whilst still requiring a separate scheduling mechanism, this approach may allow commitment of in-market resources with longer start/notification times or coordination challenges, supporting potential greater efficiencies than RERT which can only be provided by out-of-market resources. Contracting for operating reserves may additionally serve as an interim measure prior to implementation of an Operating Reserve market.

Cost recovery

AEMO notes any cost-recovery approach must be determined in close consultation with stakeholders, recommending simple arrangements as an initial design which may be uplifted through subsequent review of the value of the Operating Reserve market and suitability of more complex arrangements.

Various options are explored. The stepwise construction of the proposed ORDC may allow for the costs associated with each step of the ORDC to be allocated to relevant causer groups, for example the component associated with forecast demand ramp being allocated to loads with uncertainty components being allocated across causer groups including the relevant technology types.

Further specificity may be introduced in the future through technology type uncertainty metrics (e.g., wind/solar) to allow more targeted allocation. AEMO has considered options for per-facility uncertainty factors tied to maximum availability offers over time, however, a detailed analysis of potential outcomes associated with such a causer pays methodology would be needed to ensure the efficacy of this approach.

There are potential linkages of cost-recovery with the Scheduled Lite reform program of the ESB Post-2025. In particular that participation in Scheduled Lite may allow for an opportunity to reduce exposure to Operating Reserve costs; providing additional visibility of forecast demand and supply through Scheduled Lite can reduce uncertainty and hence the need for operating reserve.

Trade-offs of any detailed cost-recovery mechanism include simplicity and transparency, with several critical and relevant lessons from the application of causer-pays in FCAS. AEMO does not provide explicit recommendations on cost-recovery mechanisms and underscores the importance of collaboration and detailed stakeholder engagement.

Interaction with a capacity mechanism

There is close interaction between an Operating Reserve market and a Capacity Mechanism. Both mechanisms aim to ensure customer reliability with growing penetration of renewables and both pay for capacity in ahead timeframes. A Capacity Mechanism is designed for *investment* timeframes (in the scale of years), aiming to reduce the risk of a disorderly transition and provide an alternative more predictable revenue source for investors building capacity that the market needs as thermal generation exits the power system. An Operating Reserve market is designed for *operational* timeframes (in the scale of hours), aiming to reduce the risk of operator intervention and providing incentive for participants to provide capacity at times of low reserve and forecast uncertainty. An Operating Reserve market also provides investment incentive for flexible capacity, which should be further explored with stakeholders.

For any Capacity Mechanism where the performance obligation for capacity is tied to availability and bidding during periods of system stress (such as lack of reserve LOR2 or LOR3), the design should be considered carefully to ensure Operating Reserve and Capacity mechanisms are complementary.

The merit order for which capacity payments/obligations are made for availability during LOR conditions may be *precisely* determined by an Operating Reserve market of the type considered in this report.

To note, Operating Reserve markets exist alongside capacity markets in many places in the world (including ISO-NE, PJM, NYISO, CAISO, Ontario, UK, Mexico, and EirGrid), where there is recognition that the provision of capacity to meet peak demand has different value to the provision of flexible capacity at times of low reserve or forecast uncertainty. Recent considerations in the WEM further suggest exploration of separate capacity products for 'peak' and 'flexibility' for the WA Capacity Market, to separately value flexible capacity that is available to respond at times of ramping needs of the system.

AEMO recommends further detailed investigation of the interactions between a Capacity Mechanism and an Operating Reserve market for the provision of availability in operational timeframes.

Indicative costs and timings

With industry and stakeholder representatives comprising the Reform Delivery Committee, AEMO has estimated the timing and costs associated with an Operating Reserve market as part of its NEM2025 Roadmap and Gate 1 business case assessment.

Costs

To estimate delivery, AEMO used the working model provided by the AEMC and a set of working policy assumptions, including:

- Simplicity
- Current conception of policy pathway
- Typical AEMO practice
- Links to ESB reform package

AEMO costs for the implementation of an Operating Reserve market were estimated as part of the NEM2025 business case[3]. Implementation costs are estimated to be 'Large' through initial 'T-shirt sizing' estimates, with impacts across NEMDE, pre-dispatch, IT, settlements and other areas. Upfront costs are estimated as approximately $11.4m +/-40% and ongoing costs are estimated to be $7.8m (over a 10 year period). The estimates are based on the assumption that the scheduling of Operating Reserves would be performed by NEMDE, forecasting and ST PASA redevelopment projects are able to provide necessary inputs to the determination of the ORDC and that the replacement of the causer pays system can be leveraged for the settlement of the service. AEMO notes final costs will be dependent on final arrangements that are put in place for bidding, co-optimisation, cost-recovery, and compliance.

Timing

Timing for the implementation of an Operating Reserve market has been considered as part of the NEM Reform Implementation Roadmap. AEMO has estimated timing considerations from draft determination to market start, including detailed design, modelling, development, prototyping, and testing of key design features. As the

[3] AEMO | NEM Reform Implementation Roadmap

broader suite of market reform initiatives are progressed there is further opportunity to refine market implementation, in particular, opportunities to leverage interactions between parallel reforms. AEMO suggests that these options be considered at draft determination in addition to the timing estimates below.

From final determination to market start, AEMO estimates a period of approximately 3.5 years is required to complete detailed design and prototyping, development and testing, MASS and other Procedure changes. As per the above assumptions for costs, AEMO notes final timing will be dependent on final arrangements that are put in place for bidding, co-optimisation, cost-recovery, and compliance.

This relatively long delivery timeframe is a key reason why AEMO welcomes the opportunity now to progress key elements of a high-level design for an Operating Reserve market and provide this advice and perspective to AEMC in this report. If an Operating Reserve service is not implemented, AEMO will continue to develop its operational tools for the management of forecast uncertainty and ramping events and recommends that further work is undertaken by market bodies to address the operational challenges experienced during the 2022 winter crisis and Market Suspension Event.

Contents

1 Introduction

The ESB P2025 Program recommended an Operating Reserve market be considered through two industry-led AEMC rule change requests (ERC0295 and ERC0307). Both rule changes seek to address the increasing need for energy reserves in operational timeframes as the power system transforms.

In November 2021, AEMC extended the time for making a draft determination on these rule change requests to 30 June 2023 to allow for:

- data to be gathered from the provision of reserves from under the recently implemented five-minute financial settlement and wholesale demand response market
- further information on the Energy Security Board's progression of post 2025 reforms relating to a capacity mechanism and jurisdictional strategic reserve mechanism, and
- AEMO to prepare detailed technical advice.

To support the delivery of technical advice, AEMC provided a "working model" for an Operating Reserve market, designed in consultation with the market bodies and industry stakeholders. The model defines features of a 30-minute co-optimised Operating Reserve market to a level that could allow assessment against the NEO. In this model the market operator procures, on a rolling basis in every five-minute dispatch interval, a certain volume of operating reserves in MW with the capability to be dispatched as energy in the dispatch interval 30-minutes ahead.

The specific request was sent by AEMC Commissioners to AEMO on 23 Dec 2021 to provide key advice on:

1. The development of an operating reserve demand curve
2. The implementation of a causer pays cost recovery mechanism for the market
3. The reserves obligation and interaction with dispatch and other processes
4. The direct implementation costs and proposed timing of an Operating Reserve market.

This report provides this technical advice.

2 Demand and supply of operating reserve in the NEM

Every power system needs operating reserves. They have been historically provided as a fortunate by-product in the NEM, but the demand for and supply of operating reserves is changing.

2.1 Operating reserve

Every power system needs operating reserves, *"the capability to respond to large continuing changes in energy requirements"* (AEMO System Requirements[4]).

This capability to date has been provided in the National Electricity Market (NEM) from incentives in the spot market, contract market and as a by-product of the production of energy by the technologies operating in the market.

The rapid transition of the generation profile towards variable renewable energy impacts both the demand and supply of operating reserves for the system. Alongside these changes, more grid-scale storage resources are being built and various market reforms are being implemented including 5-minute settlement and the wholesale demand response mechanism.

It is difficult to predict whether the fleet and market will supply sufficient operating reserves to avoid AEMO intervention in the future, or whether interventions for lack of operating reserve will become commonplace. If they do become commonplace, a market service may provide a technology agnostic opportunity for in-market competition to drive efficient outcomes for consumers.

This section outlines the current frameworks for provision of operating reserves, the redevelopment of ST-PASA and a summary of risks for future provision including considerations of demand, supply and recent market reforms.

2.2 Current frameworks for the provision of Operating Reserves

2.2.1 Reserves calculation in ST-PASA

Calculation

Reserves are measured as the available capacity above forecast demand[5]. In practice they are resources capable of changing the supply/demand balance in the near future (from the next dispatch interval or over several hours) and can include capacity on both the supply side (generation) and the demand side (demand response).

[4] https://aemo.com.au/en/initiatives/major-programs/past-major-programs/future-power-system-security-program/power-system-requirements-paper

[5] The relevant consideration of 'forecast demand' for the purposes of calculation of reserves is 'forecast net demand', that is, demand after distributed solar generation has been accounted for. We use 'forecast demand' throughout the paper for simplicity but note that uncertainty of distributed solar will impact the probability distribution of uncertainty, and hence the calculation of reserve.

AEMO publishes forecasts of available reserve capacity through its Projected Assessments of System Adequacy (PASA) over various time scales (Short Term [ST] from 2-7 days ahead every hour, and Pre-Dispatch [PD] each day until the end of the next trading day, every half-hour). To note, PASA systems are currently under significant redevelopment, outlined further in the following section.

The forecast is based on:

- the aggregate capacity of scheduled generation (non-energy-limited)
- plus aggregate energy-limited capacity, minus aggregate semi-scheduled capacity), plus
- interconnector support, plus
- forecast aggregate semi-scheduled availability, minus
- scheduled demand.

Uncertainty is incorporated into the projection of system adequacy through the forecast uncertainty measure (FUM), generated using RXS error distributions, taking into account historical forecasted RXS minus actual RXS for various prevailing weather and generation mix scenarios.

Actions

If a reserve shortfall is identified, AEMO declares a lack of reserve condition (either forecast or actual), which fall into three classifications:

- *Lack of reserve level 1 (LOR1)*

  When forecast available capacity reserves fall below the larger value of either the FUM or the sum of the two largest credible risks in the region.

- *Lack of reserve level 2 (LOR2)*

  When forecast available capacity reserve fall below the larger value of either the FUM or the largest credible risk in the region.

- *Lack of reserve level 3 (LOR3)*

  When the forecast available capacity reserves for a region is at or below zero.

In practice, AEMO informs market participants of LOR conditions through market notices. If a reserve shortfall is identified within the period 2-7 days ahead (the ST PASA forecast), AEMO issues a market notice advising forecast LOR1 conditions (though only if they appear in the PASA calculation run completed at 1400hrs AEST). LOR2 and LOR3 conditions are declared as soon as possible after being identified.

If identified through the Pre-Dispatch PASA forecast (i.e., within the next trading day), AEMO issues a market notice advising if any LOR conditions (LOR1/LOR2/LOR3) are forecast in the current pre-dispatch period (i.e., the next trading day).

These notices provide information to market participants, supporting consideration of energy price expectations. Market participants may respond to this information by making their capacity available (i.e., as reserves) to the market.

Available capacity is defined "*The total MW capacity available for dispatch… (i.e., maximum plant availability)"* under *"expected market conditions"* (Rule clause 3.7.3e)

PASA availability is defined *“The physical plant capability (taking ambient weather conditions into account)…that can be made available during that period, on 24 hours’ notice”*

The certainty with which availability is offered is a key factor of consideration by the system operator. Generators are obliged to provide Available Capacity only ‘under expected market conditions’. This capacity can be commercially withdrawn from the market based on individual expectations of future opportunities. It is unclear what participants expect when making their offers; if the expectation of market conditions changes, they can rebid. As a result, estimates of available capacity have some attendant uncertainty, with the risk for maintaining adequate reserves to ensure security and reliability placed on the system operator if it fails to materialise voluntarily. The risks of managing system security and reliability are borne by the system operator and are primarily reputational, but ultimately borne by consumers through the probability and value of lost load.

PASA availability (the amount generators can make physically available with a 24 hour recall) does not need to correspond to maximum available capacity under the expected market conditions, but also does not always reflect what capacity is offered into market, with resulting risk again placed on the system operator.

> *“The following short term PASA inputs must be submitted by each relevant Scheduled Generator and Market Participant…and must represent current intentions and best estimates*”
>
> *1) “available capacity…under the expected market conditions”*
>
> *2) “PASA availability”*
>
> (Source: National Electricity Rules clause 3.7.3e)

Intervention

AEMO may use a range of tools if it considers that the market has not responded to published information by making reserves available that are sufficient to ensure the security and/or reliability of the power system. Firstly, AEMO may take actions such as revising plant ratings, revising system limits or recalling outages (or otherwise reconfiguring the network). These options and their hierarchy are described in the Power System Security Guidelines[6]. As a last resort, AEMO may take one of three forms of intervention as described below[7]:

- Directions, which are issued to registered participants (generators and scheduled loads) to operate at a specified output or consumption level.
- Instructions, which are final resort notices which require large energy users and distribution network service providers to load shed, or
- Activating reserve via the Reliability and Emergency Reserve Trader (RERT)

The timeframes for delivery of RERT services are an important consideration in terms of how RERT might be used to deliver operating reserves, and what an operating reserve service could deliver compared to what is delivered through existing mechanisms. We refer to the three types of RERT services described below throughout the report:

- Type 1 - RERT that can be exercised in < 30 minutes (that is the sum of pre-activation and activation times is < 30 minutes).
- Type 2 – RERT that has a sum of pre-activation time and activation time ≥ 30 minutes and an activation time < 30 minutes.
- Type 3 – RERT that has activation times > 30 minutes, regardless of any pre-activation time.

[6] SO_OP_3715 Power System Security Guidelines 2022

[7] AEMC RERT Guidelines 2020

As Type 1 RERT can be exercised in < 30 minutes it can be dispatched/activated post contingency, that is, when an actual LOR 3 occurs.

Type 2 RERT must be pre-activated in time to ensure it can be dispatched/activated at any time during the reserve shortfall. As with Type 1 RERT, Type 2 RERT will only be dispatched/activated post contingency.

Type 3 RERT must be pre-activated and dispatched/activated to ensure RERT is being delivered by start of any LOR 2 period.

The costs of delivering energy when RERT is activated often exceed the market price cap (MPC), though are required under guidelines to not exceed the value of customer reliability. AEMO publishes quarterly reports of all LOR events identifying causes and contributing market conditions.[8]

2.2.2 Redevelopment of ST-PASA

AEMO is currently conducting a comprehensive review of the pre-dispatch PASA and ST PASA methodology in its ST PASA replacement project and is exploring the development of a system that will serve the NEM now and into the future.

AEMO are conducting workshops to provide stakeholders and AEMO the opportunity to discuss the technical concepts of the ST PASA Replacement Project in more detail ahead of its formal consultation on the ST PASA procedure and guidelines. This includes use of uncertainty margins and confidence levels and proposals on determination of LOR levels.

The information in this section represents high-level, initial proposals for redeveloped ST PASA design that may change with further consultation.

Uncertainty margin

Under the redeveloped ST PASA, forecast uncertainty is proposed to be represented by an Uncertainty Margin (UM), defined as:

> *An amount of MWs that represents expected conditional forecast error given a confidence level[9] used to adjust the load, VRE forecasts and scheduled generation max availability and ensure sufficient supply to meet demand.*

A methodology to produce Uncertainty Margins is being developed as part of the ST PASA replacement project and will form part of the formal consultation on the ST PASA procedure and guidelines.

We explore the possibility of the Uncertainty Margin generating an efficient probabilistic Operating Reserve Demand Curve in detail in Section 4.4.

Updated intervention framework

Work is also underway to determine appropriate confidence levels to be used in the proposed Lack of Reserve levels. It is currently proposed that the LOR levels will change to more explicitly consider forecast uncertainty, represented by the Uncertainty Margin at different confidence levels. The proposed new framework will no longer solely use LCRs; an LOR will instead be declared when there is insufficient supply to meet 50% POE demand plus an uncertainty margin.

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[8] AEMO RERT Operating Procedures, 2020

[9] An x% confidence level means that we are x% confident that the forecast error will not exceed this value.

It is also proposed that the reserve assessments will be made at a more granular, 'nodal' level, as opposed to a regional level. It is intended that results will be aggregated to be reported on a regional basis.

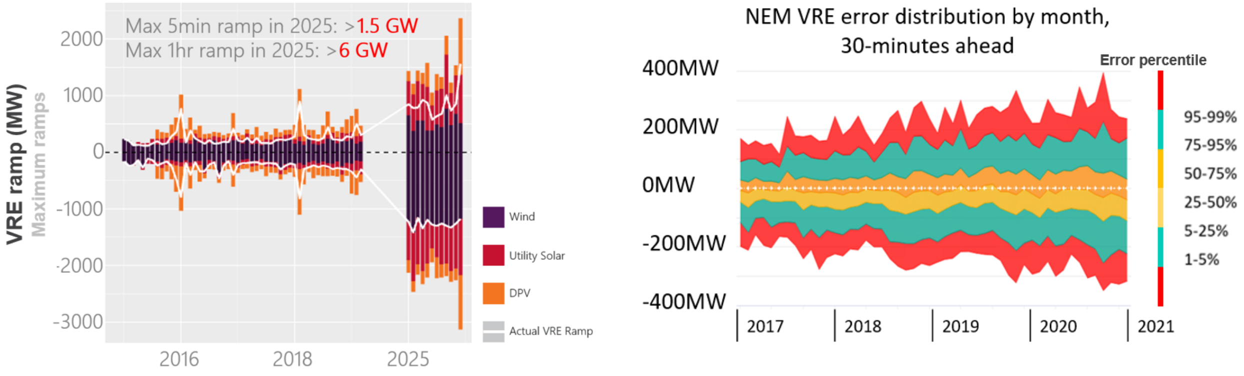
Table 2 Proposal for Lack of Reserve levels under redeveloped ST PASA

Current regional LOR Levels	Proposed regional LOR levels	Potential trigger for market intervention?
LOR 3 When the forecast of available capacity reserves is at or below zero.	LOR RED Cannot meet demand, where demand equals 50% POE demand plus an Uncertainty Margin at x% confidence level.	Yes
LOR 2 When the forecast of available capacity reserves is less than the largest credible risk (the FUM is also considered at this point.)	LOR ORANGE Cannot meet demand if we have a credible network contingency or a credible generation contingency in the NEM. Demand is defined as 50% POE demand plus an Uncertainty Margin at x% confidence level.	Yes
LOR 1 When the forecast of available capacity reserves is less than the largest and the second largest credible risks (the FUM is also considered at this point.)	LOR YELLOW Cannot meet demand if we have a credible network contingency or a credible generation contingency in the NEM. Demand is defined as 50% POE demand plus an Uncertainty Margin at y% confidence level, where y>x. (noting that these confidence levels are currently under consideration through ST-PASA redevelopment)	No

2.3 Risks for future provision of Operating Reserves

2.3.1 Demand side changes

AEMO is observing rapid change in the power system including lower minimum demands, higher winter peak demands, higher variable renewable energy (VRE) penetration and decommitments of thermal plant. Demand for operating reserve is increasing due to growing variability and uncertainty. There have been increasing instances of very large variability, exceeding forecasts in the AEMO Renewable Integration Study of 2020 (Figure 5, left).



Adapted from AEMO Renewable Integration Study, Stage 1 2020

Figure 5 Evidence of growing demand for operating reserves. Left) actual and forecast variability from the AEMO Renewable Integration Study Stage 1 2020, Right) Forecast uncertainty trends.

Not all of this variability is 'unforecastable' – the sun goes down every day, but a significant proportion of VRE ramping events are difficult to forecast, either from wind variability, scudding cloud cover, or rapidly moving weather fronts - VRE error distribution is steadily increasing (Figure 5, right).

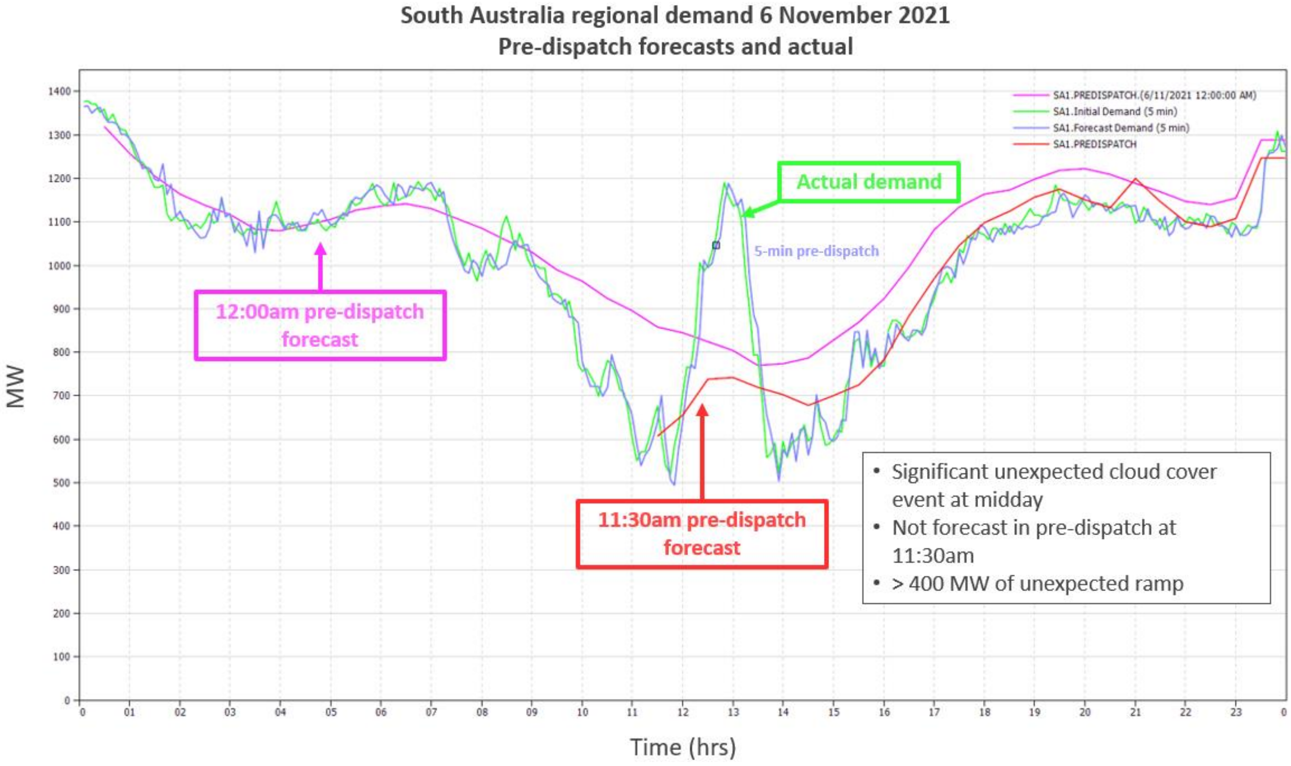


Figure 6 An example day in South Australia, 6 November 2021, showing a significant unexpected ramping event due to cloud cover.

Beyond the broader system trends, there are increasing occurrences of uncertainty in net demand contributing to significant power system risk (Figure 6). Alongside this is increasing risk of lack of reserves, as evidenced by the number of declarations of Lack of Reserve (LOR) conditions (either forecast or actual). In quarters 2 and 3 of 2022 alone, 659 lack of reserve notices were issued, whereas 198 notices were issued in the 3-year period from 2018-2020.

It is important to note that whilst the Forecast Uncertainty Measure has occasionally provided the trigger for LOR1 notices, AEMO to date has not intervened in the market solely as a result of uncertainty, that is, the FUM has not triggered an actual LOR2 to date. Forecast uncertainty will likely become a greater contributing factor to AEMO intervention, mechanisms to quantify and better manage uncertainty will occur as part of the redevelopment of ST PASA.

2.3.2 Supply side changes

Supply for operating reserve is impacted by changes in the dispatchability of capacity that is online, and the incentives for capacity to be online at times where there is a risk of insufficient reserve. The incentives to provide online dispatchable operating reserves are changing in a future NEM where semi-scheduled/non-scheduled resources regularly provide the majority of capacity at low short-run marginal cost. The nature of reserves being provided is dramatically changing, including the plant providing reserve, the timing in which it is provided ahead, and the certainty of the reserve being available if required. AEMO is observing changed operating regimes from participants, for example, generators running at lower loads and gas plant being on standby rather than committed and on-line. These issues are changing the nature of reserves being provided; ramping capability is increasingly being expected from offline or energy limited resources as opposed to on-line resources. Whilst there is an expectation of slightly greater flexibility in the future fleet (Figure 7), there is emerging evidence that at times of low reserve there is already insufficient incentive for the fleet to offer capacity.

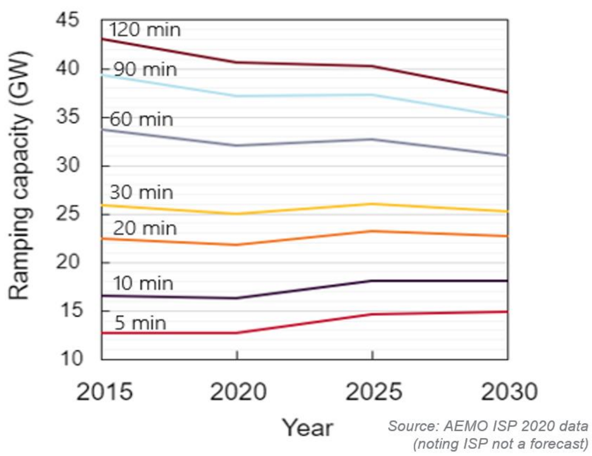


Figure 7 Ramping capacity projections included in the AEMO ISP 2020.

Figure 8 presents data on prices at times of low reserve (LOR 1 or LOR 2 events) in South Australia over 2013-2021. The trend over time is for there to be more periods of low reserve (more dots for later years), occurring deeper (dots trending leftward over time), and occurring with greater frequency at moderate demand (<50th percentile, increasing number of circle-markers instead of triangle-markers).

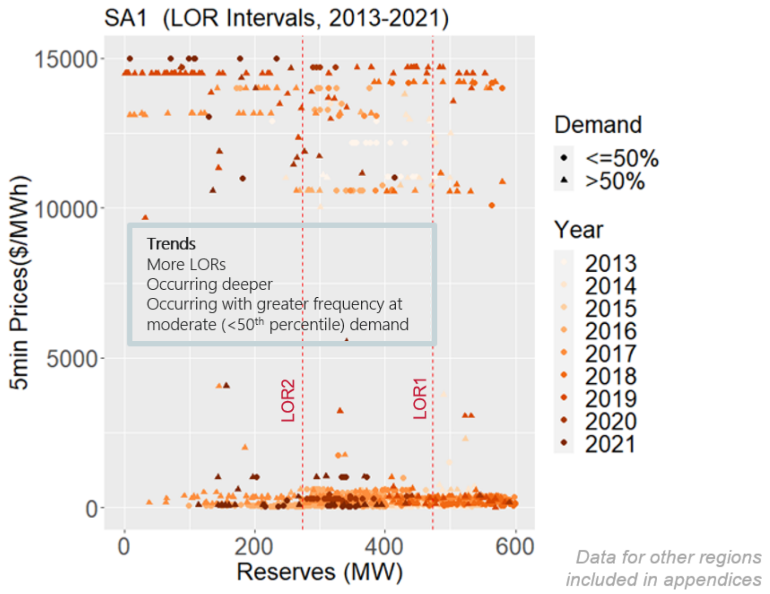


Figure 8. Price vs Reserve data for South Australian LOR intervals 2013-2021 (pre 5MS) showing an increase in LORs, occurring deeper, and occurring with greater frequency at moderate (<50th percentile) demand.

There are range of contributing factors to price and reserve levels. Further interrogation of this data will allow exploration of the number and type of days for which the low-price/low-reserve intervals occur, and surrounding context. But the existence of low prices during periods of low reserves highlights that spot market prices, nor secondary contracts, are not always providing sufficient incentive for resources to be online and available during times of low reserve. This data is particularly relevant for the consideration of an Operating Reserve, which would explicitly value availability at times of low reserve.

Recent data following the implementation of 5-minute settlement highlights that low-price/low-reserves events are not purely artifacts of historical 30-minute settlement in the NEM either (Figure 9).

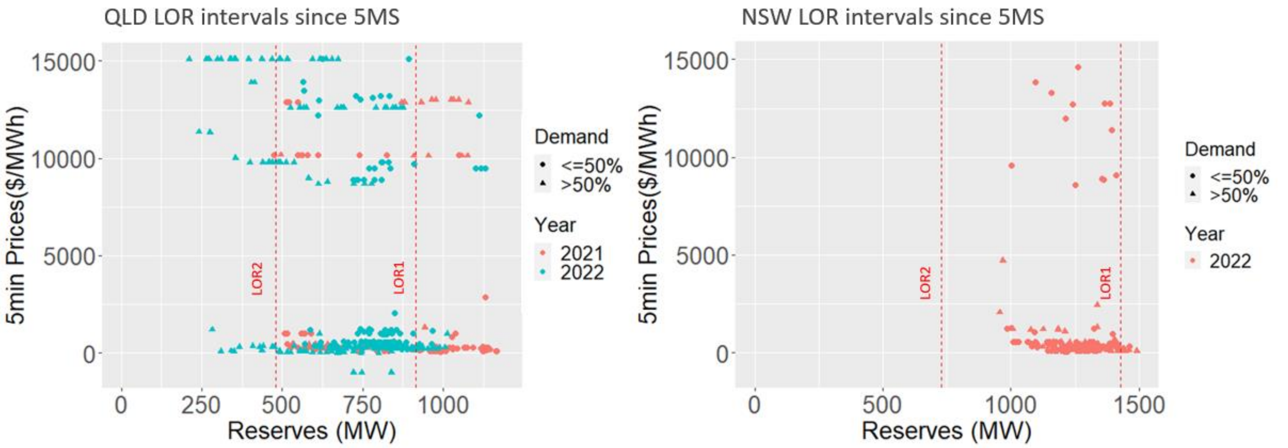


Figure 9 Price vs Reserve data for QLD (left) and NSW (right) LOR intervals following the implementation of 5-minute settlement. There is a significant number of intervals, even in the short period of time since 5MS, with low reserves (<LOR1), low demand (<50th percentile, [circles]), and suppressed prices (significantly below MPC).

There are a significant number of intervals, even in the short period of time since 5MS, in both QLD and NSW with low reserves (<LOR1), low demand (<50th percentile – circle markers), and suppressed prices (significantly below MPC). Periods with low demand, low reserves, and high prices also warrant further investigation and suggest commercial availability may not always be responding at times of low reserves. Some resources may further incur a cost to provide operating reserve without being explicitly rewarded for doing so through contracting arrangements. For both Figure 8 and Figure 9, selected intervals may be subject to intervention pricing, which should further sharpen incentives to be online and providing reserves. AEMO suggests the correlation of price and reserves be investigated in more detail alongside stakeholder consultation towards draft determination by the AEMC. Of interest will be deeper analysis of the number and 'type' of days over which these intervals occurred and the reasons for participant availability during these times.

As the system transitions towards higher penetration of renewables, low energy prices during middle of day are a signal for thermal plant to decommit or to not operate at all for multiple days, reducing the amount of operating reserve provided to the system. Some resources incur a cost to provide operating reserve currently, but do not get explicitly rewarded for doing so. An Operating Reserve market would aim to correct this.

Commercial availability

The certainty with which availability is offered is a key factor of consideration by the system operator.

Generators are obliged to provide maximum plant availability 'under expected market conditions' (Rule clause 3.7.3e). It is unclear what participants expect when making their offers; if the expectation of market conditions changes, they can rebid. As a result, estimates of available capacity have some attendant uncertainty, with the risk placed on the system operator if it fails to materialise. There may be additional avenues to improve AEMO visibility of availability and market participant expectations, and we note some measures are included in current and proposed arrangements for ST-PASA and pre-dispatch.

PASA availability does not need to correspond to maximum available capacity under the expected market conditions, and there is increasing difference between PASA availability and Maximum availability (provided for Pre-Dispatch), and uncertainty regarding the dispatchability of offered capacity at all times. This is adding to the uncertainty to which requirements for operating reserve will be met.

With regular low energy prices, and the likelihood of a prolonged step change in gas fuel prices, there is increased risk that gas powered generation will not always want to run across the day or start twice a day. There is further risk for coal units to be offline more frequently due to various reasons. Whilst there may be new batteries and hydro resources available to mitigate some of this risk, there is a still potential for frequent shortage of reserve to occur in operational timeframes, particularly where the depth of storage is insufficient to respond to both expected and unexpected ramping events. AEMO sees a particular risk emerging from 2023 following thermal plant closures, at times when there is minimal solar in the mornings or over the evening peak in winter.

Ramping

To explore system capability as South Australia progresses towards higher levels of renewable penetration, AEMO undertook a timeseries analysis of available 5-minute headroom in SA from January 2020 to May 2021 to explore ramping risks in SA, to inform the Engineering Framework[10].

[10] https://aemo.com.au/en/initiatives/major-programs/engineering-framework

Historical 5-minute headroom was found to be insufficient for relatively few days in the time period, though there is possibility the directions for system strength may have masked the natural levels of headroom provision. Extrapolating distributed solar PV levels to 2026 with a hypothetical cloud cover event indicates that headroom may be of sufficient concern to force intervention. (Figure 10).

As a result of the uncertainty in the magnitude of worst-case ramps with increasing VRE, as well as how accurately the ramps can be forecast, AEMO has instigated precautionary measures to commence now including:

- Development of operational and control room tools to monitor ramping risk and ramping headroom
- Exploring the potential for control room and market procedures to increase headroom
- Implementing new operational forecasting tools
- Exploring the need for more detailed planning studies and analysis to forecast upcoming ramping adequacy risks

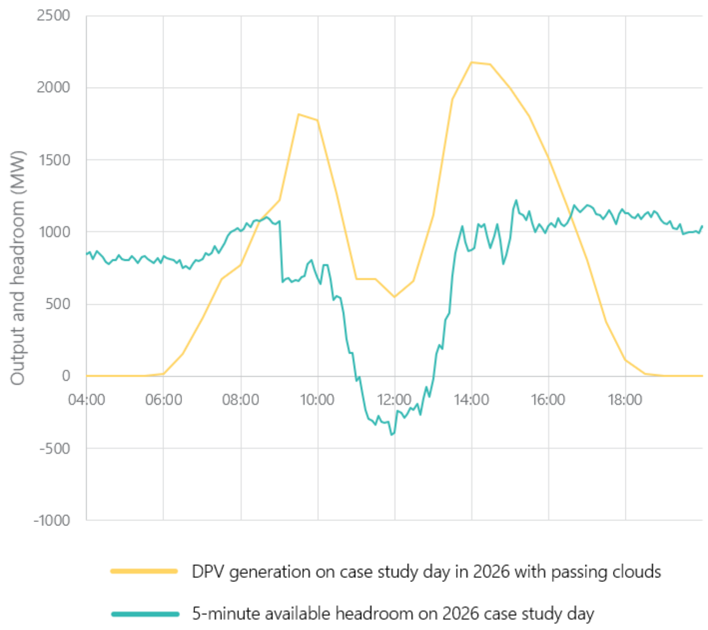


Figure 10. AEMO engineering study of SA available headroom on a hypothetical day in 2026 with high DPV penetration and passing clouds.

Future studies of interest may include investigation of 30-minute headroom with very high VRE penetration.

2.3.3 Perspectives on the 2022 NEM winter crisis

In winter 2022, a confluence of high commodity prices, domestic market price caps, planned and unplanned outages of scheduled generating plant, fuel constraints, very low output from semi-scheduled generation and high winter demand conditions led to unprecedented challenges operating the NEM. These conditions required AEMO to suspend the spot market in all regions of the NEM from 15-24 June, though AEMO notes that extraordinary conditions prevailed in the NEM in the months before and after the suspension (the 'winter crisis'). AEMO has provided detailed analysis of the suspension event, contributing factors, and subsequent recommendations in a publicly available event report[11]. Key recommendations outlined in the event report include

i) AEMO to prepare a plan for when the Cumulative Pricing Threshold is likely to be breached

ii) AEMO to upgrade control room tools

iii) AEMO to continue to actively engage with the AEMC and industry regarding reviews or rule change proposals relating to the Administered Price Cap, Cumulative Price Threshold and other market settings that influence the operation of the NEM. AEMO is also conducting a review of gas market prices/parameters.

iii) AEMO to review processes used for projecting supply adequacy over the medium term

AEMO notes here that an Operating Reserve market would have been unlikely to address the contributing factors that led to market suspension. However, the winter crisis highlighted a number of challenges for power system operation concerning supply adequacy, energy-limited plant, spot-market pricing and commitment. We review possible measures to address these below, including the scope of what an Operating Reserve market may achieve.

2.3.4 System concerns relating to supply adequacy and reserves and potential measures to address

AEMO has identified a range of power system issues related to the provision of availability at times of resource scarcity. We summarise these below with an initial assessment of how various measures may address these problems. The measures we consider are:

i) An Operating Reserve market – a new market ancillary service, as per the working model of this report

ii) Operational actions such as a) contracting for operating reserves (e.g., under NSCAS). b) VRE curtailment, and/or c) constraining interconnectors to maintain headroom.

iii) Short-term trading of energy and operating reserve. An ahead market would provide market participants an opportunity to trade energy and operating reserve, and make commitment decisions, across the operational horizon.

List of power system issues related to operating reserves	Potential measures to address problems		
	Operating Reserve market	Operational actions such as contracting for reserves, curtailing VRE, and/or constraining interconnectors	Short-term trading of energy and operating reserve
Challenges associated with managing and	Weak	Partial	Yes

[11] https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-events-and-reports

List of power system issues related to operating reserves	Potential measures to address problems		
	Operating Reserve market	Operational actions such as contracting for reserves, curtailing VRE, and/or constraining interconnectors	Short-term trading of energy and operating reserve
optimising energy-limited plant over operational horizon.		(additional operational tools would be required in parallel)	
High cost / lack of commitment by thermal plant with long start times	Weak	Yes	Yes
Lack of commitment of ramping reserves prior to last time to intervene	Reliant on confidence in pre-dispatch and participant expectation of OR prices	Yes (contractual obligation)	Yes (noting that resources could choose to not commit prior to dispatch, but this would likely be at substantial cost)
Increased intervention by AEMO due to lack of reserves	Reliant on confidence in pre-dispatch and participant expectation of OR prices	Yes (noting exercising contracts would have an impact on the spot market)	Yes
Growing forecast uncertainty as VRE penetration increases	Yes	Only if reserves enabled at times of high uncertainty (noting uncertainty margins, and hence required reserves, would be greater the earlier reserves are triggered).	Yes
Growing changes in ramping requirements (expected ramps) as VRE penetration increases	Yes	Yes (additional operational tools would need to be developed in parallel to identify ramping events)	Yes

List of power system issues related to operating reserves	Potential measures to address problems		
	Operating Reserve market	Operational actions such as contracting for reserves, curtailing VRE, and/or constraining interconnectors	Short-term trading of energy and operating reserve
Increasing occurrence of low prices and low reserves at times of high VRE generation	Yes	No Enabling reserve contracts could further reduce energy prices	Yes
Lack of visibility and dispatchability of VPPs (and other demand side price responsive resources).	Yes	Contracts could be with VPPs, however high administrative burden if not integrated with registration and dispatch	Yes
High penetration of VRE (e.g., middle of day) presents difficulty for commitment of resources that are needed to meet ramping needs	Yes Curtailed VRE could offer into OR creating space for flexible resources (e.g., GPG) to be online.	Yes	Yes
Very large investment in fast ramping resources required by 2030 under ISP step change scenario	Weak	No	Weak

It is important to note that any capability of an Operating Reserve market to address power system challenges depends closely on compliance arrangements and system operator confidence behind pre-dispatch forecasts of operating reserve. Similar to the uncertainty that accompanies pre-dispatch forecasts for the energy spot market due to commercial rebidding, pre-dispatch offers of Operating Reserve will also have attendant uncertainty. Without robust and enforceable compliance mechanisms, this inherited uncertainty of pre-dispatch forecasts of Operating Reserve availability counteracts the objective of the new market to avoid intervention if required to maintain system security and reliability. Market signals and high prices have not always yielded expected responses from market participants, most recently witnessed during the winter crisis associated with the market suspension event of June 2022.[12]

For example, during the crisis but outside periods of administered pricing or market suspension, AEMO observed cases with very high energy prices where fast-start units were given start signals in accordance with their offers, but then re-bid to make themselves unavailable due to non-technical reasons. This suggests that the current set

[12] https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-events-and-reports

of compliance arrangements are not deterring some participants from acting against the intentions they are conveying to the market. In itself, this is a material issue for the effective management of power system reliability and one that AEMO considers should be addressed. In the context of OR, operator confidence in the effectiveness of the compliance regime is a prerequisite for a product that aims to reduce the likelihood of operator intervention.

We underscore in this section the mixed capability of an Operating Reserve market to address various power system challenges concerning capacity availability outlined above, but focus attention now for the following sections and the high-level design on the specific challenge of maintaining sufficient operating reserves to meet increased forecast uncertainty in the power system whilst avoiding increased intervention through RERT.

2.3.5 Perspectives on current reforms to provide operating reserve

A number of reforms to the wholesale energy market are underway, but it is not clear if any will impact the demand for or provision of operating reserve. The recent implementation of 5-minute settlement supports participation from flexible, fast ramping resources, though may exacerbate scarcity of reserves from resources with high start or enablement costs (like GPG and demand response).

Increasing occurrences of scarcity-induced price spikes will likely encourage flexible participants to position resources to provide energy arbitrage, but it is not clear if it will increase the provision of operating reserve during times of high forecast uncertainty and/or low reserve. That is, with very high VRE penetration, there will be times of significant forecast uncertainty. It is unclear how participants, including storage participants, will commit resources to cover expected ramps (e.g., day end), versus maintaining capacity for availability due to forecast uncertainty. AEMO notes there may be value in the visibility and communication of aggregated storage depth by region.

Similarly, whilst the wholesale demand response mechanism will support greater demand side participation, it is unclear what availability there will be at times of high forecast uncertainty and/or low reserve. It is further unclear how distributed resources will participate in scheduling without further incentives to do so. The Scheduled Lite mechanism will reduce barriers for loads, VPPs and small generators to participate in the dispatch process however there are limited incentives for these resources to participate in market. The introduction of an Operating Reserve market could provide a strong incentive for demand side resources to participate in dispatch and make valuable contributions to power system requirements. While demand side resources are currently a small portion of the firm and flexible capacity in the NEM, the capacity is expected to grow significantly with the uptake of household batteries, EVs and other smart devices. Operating Reserves would also provide an incentive to demand side resources to provide accurate forecasts in order to reduce their exposure to Operating Reserve cost recovery.

Several options have been considered for a capacity mechanism to maintain resource adequacy as thermal resources retire, and there is close interaction between an Operating Reserve market and such a mechanism. Both aim to ensure customer reliability with growing penetration of renewables, and both pay for capacity in ahead timeframes.

Interactions are discussed in more detail below, but it is not clear how the future capacity will be capable or willing to provide operating reserve at times of high forecast uncertainty and/or low reserve, and how this may interact with any performance or penalty structures. With the building of significant battery and storage assets, it is possible that in the far future there may be sufficient storage to meet ramping/reserve requirements for a broadly electrified energy sector – but until this point, the value of an operating reserve is to manage variability/uncertainty/ramping requirements. That is, predominantly to solve the online/offline problem of participants choosing to position themselves for unexpected ramps during periods of high renewable penetration or maintaining headroom in the face of forecast uncertainty, for which there is significant emerging risk not addressed by current reforms or investment.

The relationship between an Operational Security Mechanism (OSM) and Operating Reserves requires further detailed consideration, noting AEMC intention for the OSM to be unable to schedule resources for the 'sole purpose' of reliability. There is possibility for interaction where reserves are required for system security and a contracting route is employed, but at this stage we consider each reform independently.

2.3.6 Asymmetric risks

The energy spot market of the NEM with current market price cap of $15,500 is designed to encourage participant capacity being available at times of scarcity and to support investment to meet the reliability standard. Where participants do not make themselves available and instead miss out on high revenue or are exposed to high costs, the economic design theory of the NEM is built on the premise that i) participants will rapidly learn to be better positioned in the future, and ii) high prices attract investment to build capacity that can best take advantage of them.

Contracting

Whilst the secondary contract market supports participants in managing risks of exposure to the energy spot market there remains residual asymmetry of risk between participants and the system operator during times of high forecast uncertainty. The future power system may see regular occurrence of low energy spot market prices at times of significant uncertainty, and participant appetite to position resources at these times may not always align with requirements of the system operator who has a different legislated obligation than participants and consequently a different risk appetite for resource scarcity.

The energy market does not always provide signals that reflect the vulnerability of the system to a net loss of reserves over a short timeframe (e.g., unexpected increase in demand or drop in wind), increasingly occurring at times of only moderate demand. The risks for AEMO in managing reliability are not symmetric with the risks to participants managing their portfolios either in the spot market or through contracts.

It is not clear if the contract market will continue to drive commitment of resources, and in turn, mitigate risk for the system operator at times of forecast uncertainty. To clarify, the risks to the system operator are in meeting obligations for security and reliability, which in turn carries reputational risk, but more importantly, risk to the customer in meeting the reliability standard.

Feedback from some gas plant generator owners is that following 5-minute settlement, there is less contracting in conventional peak and options products. There is further expectation of contracting behaviour of thermal plant to change as operational patterns change. Cases of high VRE penetration, low prices and high uncertainty are of concern and forecast to increase in frequency.

International perspectives

In February 2021, the Electric Reliability Council of Texas (ERCOT) experienced shortfalls of generation resulting in a state-wide blackout and the loss of more than 200 lives.

Mays et al., in Joule (2022) explored the allocation of risk between participants and the system operator and its resultant effect on resilience. Texas has both a real-time energy only electricity market and an operating reserves market formulated with a demand curve – which serves as a price adder in the real-time market:

"Energy-only electricity markets, such as the Electric Reliability Council of Texas (ERCOT), rely on the decentralized investment decisions of market participants to lead to a resource mix providing an efficient level of reliability. During an exceptionally cold winter storm in February 2021, ERCOT experienced shortfalls on an unprecedented scale, with nearly half of the generation fleet experiencing outages at the peak. The depth of the resulting blackouts invites questions regarding the ability of systems relying on decentralized planning to appropriately prepare for and withstand rare events. Based on two mild assumptions, risk aversion among investors and incomplete risk trading, this paper provides an explanation for why decentralized markets are prone to underinvestment in resilience."

Their conclusion:

"The ideal of a complete competitive market holds appeal due to its potential to attract efficient investment in socially beneficial infrastructure with fewer of the incentive issues associated with regulated monopolies. The catastrophic failure of the ERCOT system in February 2021 prompts serious questions regarding how to ensure that markets deliver on their promise of socially efficient outcomes… The stark divergence in outcomes reflects severely misaligned incentives, reinforcing that successful reforms will focus on the allocation and sharing of risk. This paper argues that merely relying on refinements to spot pricing or improved modeling of correlated failures will not solve this fundamental issue."

- J. Mays et al, 2022, Private risk and social resilience in liberalized electricity markets, Joule 6, 1, https://doi.org/10.1016/j.joule.2022.01.004

AEMO sees a similar risk of misaligned incentives in the NEM and supports regulatory reforms to support resilience over both short- and long-term horizons.

There is further discussion of the value of scarcity-pricing and real-time reserve in supporting high penetrations of renewables with resilience in European electricity markets.

"Scarcity pricing is a valuable step towards the evolution of electricity markets that rely increasingly on reserves for enabling the large-scale penetration of renewable resources. A real-time market for reserve capacity is essential in the implementation of scarcity pricing, in order to enable the back-propagation of the value of reserve capacity to forward markets for energy and reserve. "

The conclusion:

The European electricity market, like any electricity market that aims at relying increasingly on renewable resources, will need to adapt to the value shift from energy to reserve capacity that is induced by renewable resources. The absence of a real-time market for reserve capacity, i.e., a market for settling reserve imbalances in real time, is a serious handicap of the European electricity market towards achieving this transition….

Scarcity pricing emerges as a no-regret measure in this respect. The appeal of scarcity pricing is that, if a system is not under stress, the scarcity pricing mechanism dissipates, and the market reverts back to its default state. The mechanism only becomes active when the system is under stress, and works towards relieving this stress.

- A. Papavisilou, 2020, Scarcity pricing and the missing European market for real-time reserve capacity. The Electricity Journal (33), 10, 106863 https://doi.org/10.1016/j.tej.2020.106863

2.3.7 Summary of risk and consideration of value

AEMO is already witnessing the impacts of increased variability, uncertainty and falling levels of reserves. There is an asymmetry of risk between participants and the system operator during times of high forecast uncertainty. Whilst there are several reforms of the wholesale energy market underway, none directly target operating reserve and forecast uncertainty. If the future fleet with associated secondary contracts does not sufficiently provide incentive for resources to be available, there is significant risk that AEMO will be forced to regularly intervene.

If regular intervention is considered inefficient, there is a range of potential options to provide additional operating reserves (Figure 11). These include adjustment or additional procurement of RERT services, designing and activating new contracts for reserve, or if a market approach is considered more efficient, implementing a market for reserves – either similar to those provided by 'RERT-type' services or reserves of a different nature.

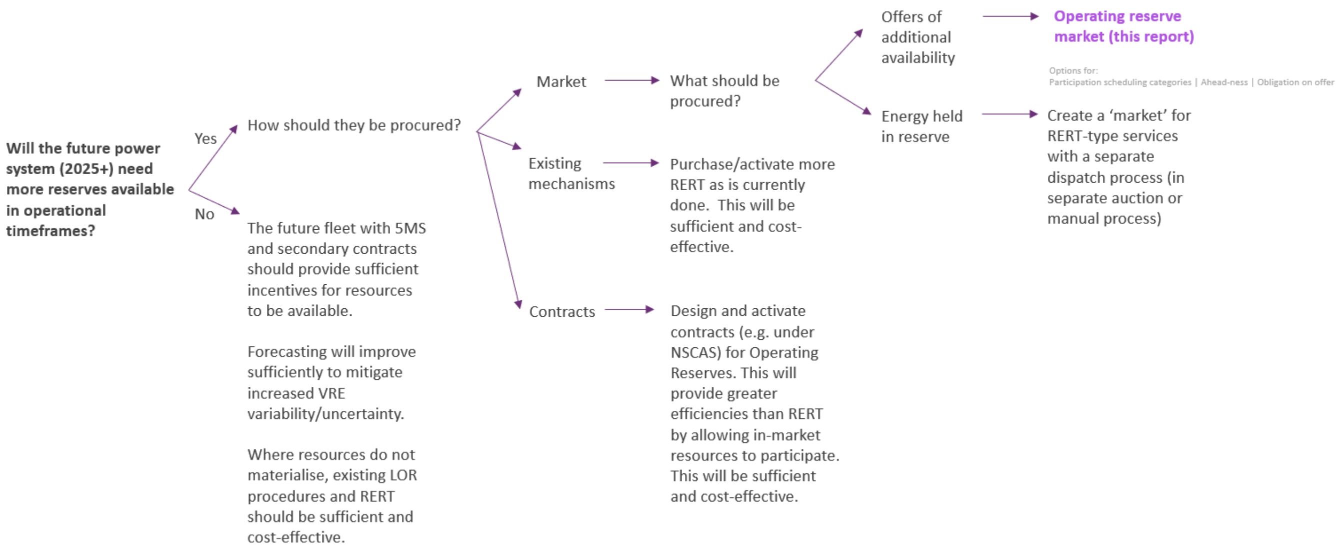


Figure 11 Options to address potential need for operating reserves

The value of an Operating Reserve market approach, however, is to tie the provision of operating reserve to offers of availability in the energy spot market. Instead of creating a new market for capacity that is not allowed to participate in the energy spot market (as for RERT providers), the aim of an Operating Reserve market would be to bring that capacity into the energy spot market, separately valuing the availability of flexible, responsive resources, and in doing so provide an explicit signal for their provision. In particular, establishing a new reserve services market could:

- Reduce AEMO intervention for instances of lack of reserve (including procurement and activation of the Reliability and Emergency Reserve Trader [RERT])
- Signal a scarcity of reserves across the operational horizon facilitating the coordination of resources.
- Encourage out-of-market resources (e.g., RERT Type 1 and 2 services) to participate in-market to respond to unexpected changes in net demand, and in doing so, increase competition in the supply of energy and systems services.
- Encourage participation of demand side resources as scheduled resources in wholesale markets. There are currently limited incentives to participate in scheduling for this expanding sector of the power system.
- Support power system resilience in procuring greater reserves than current minimum levels when efficient

- Incentivise investment in flexible dispatchable resources, and reward resources that regularly provide reserves to the market but are infrequently dispatched for energy.

There are certain instances of resource participation where an Operating Reserve product may be particularly helpful, including:

a. For currently offline resources

   An Operating Reserve market provides incentive to come online or stay online through surety that cleared Operating Reserve inclusive of start-up and minimum-generation costs can be met regardless of dispatch outcomes.

b. For resources that have made some of their capacity commercially unavailable.

   An Operating Reserve market provides additional incentive to become available and/or come online as above.

c. For resources that see value in reducing generation to receive payment for availability (increasing headroom), in turn creating room for other resources to stay online

   There may be instances where VRE (with or without firming) or other resources may see value in withholding headroom to participate in an Operating Reserve market. This would have a broader effect of sharpening the real-time price and the incentive for other resources to be online.

d. For demand response resources that require advance notice to become available

   An Operating Reserve market would support participation with sufficient lead-time to coordinate preparedness for demand response actions.

e. For storage resources

   An Operating Reserve market would support positioning with adequate depth of storage to meet reserve requirements.

For the reasons above, AEMO welcomes the opportunity to progress key elements of high-level design of an Operating Reserve market and provide this advice and perspective to AEMC to support expedited implementation if deemed in the long-term interests of consumers.

3 Working model

An indicative working model of an Operating Reserve market (as per attachment to the AEMC's request for advice).

3.1 Overview

There are a range of options available to incentivise and marshal resources to be available to provide reserve. To support AEMO to provide technical advice, AEMC attached a "working model" of a 30-minute co-optimised Operating Reserve market for the NEM, outlined below and designed in consultation with the market bodies and industry stakeholders, which defines features to a level that allows clear assessment against the NEO. In this model the market operator procures, on a rolling basis in every five-minute dispatch interval, a certain volume in MW of the capability to be dispatched as energy in the dispatch interval 30-minutes ahead.

AEMO notes that the appropriate 'ahead-ness' of procurement of an Operating Reserve market requires detailed consideration alongside the nature of reserve obligation and interaction with intervention frameworks currently under redevelopment. For an Operating Reserve market that procures "additional-availability-in-ahead-timeframes" there are trade-offs between participant management of future availability and how they are able to manage price risks, and system operator visibility of availability and opportunities to intervene if required. A further key time-frame is that of market activation, with pre-dispatch visibility of availability in the hours ahead of significant forecast uncertainty. AEMO explores considerations of various timeframes in detail in Section 5.1, noting again stakeholder input is critical, but has proceeded here with design based on the working model of a 30-minute ahead product.

3.2 Working Model – as per attachment to the AEMC's request for advice

The procurement of reserves would be **in-market** and co-optimised with the procurement of energy and FCAS. A market participant can offer capacity into the reserve market that is capable of being dispatched as energy in the dispatch interval 30-minutes ahead. The NEM dispatch engine (NEMDE) would then co-optimise offers for the energy, FCAS and reserve markets. That is, every five minutes NEMDE would dispatch resources to meet the need for each of those services at the lowest total cost of production across all services.

The market would be for a **raise only service** because there is currently no indication that there is value in procuring a reserves lower service. (If this was decided to be implemented it could be designed in such a way that a lower service could be implemented at some future point if that was warranted).

0The **procurement price and quantity** of reserves would be set dynamically based on a centrally determined demand curve, called an 'operating reserve demand curve (ORDC)'. The ORDC would be updated every five-minutes and reserves would be procured to the level where offers (volumes and prices) to supply operating reserves intersect the ORDC. The ORDC would reflect the value that consumers place on having capacity in reserve, which is the product of the value of lost load and the probability that load may be lost. AEMO would also procure a "step" in the curve at a higher price that would reflect the level of reserves required to avoid interventions to support reserve levels.

Reserves would be procured every **five minutes**. The level of reserves procured would reflect the reserve requirement (based on a forecast uncertainty measure) for **30-minutes** into the future. Any participant capable of being dispatched for a unit of energy 30-minutes in the future would be an eligible reserve provider. The 30-minute basis for reserve levels reflects the current requirement adopted in contingency planning to return the system to a secure state within 30-minutes. It also broadly reflects the time that sufficient reserve capacity would be able to start-up and/or ramp-up (or down) to provide reserves in response to prices in the energy market.

In the dispatch interval that a participant is enabled for reserves, the participant's bids in the energy market for each dispatch interval over the next 30-minutes must be consistent with providing that level of reserve as energy in 30-minutes' time. In subsequent intervals the reserve provider may change the volumes it is willing to bid to provide energy at different prices, but is not able to lower its maximum available capacity for the interval that corresponds with its reserves commitment (the interval 30 minutes after dispatch as reserves). In order to comply, a unit with a start-up profile longer than five minutes would need to be online and at minimum generation by the necessary time.

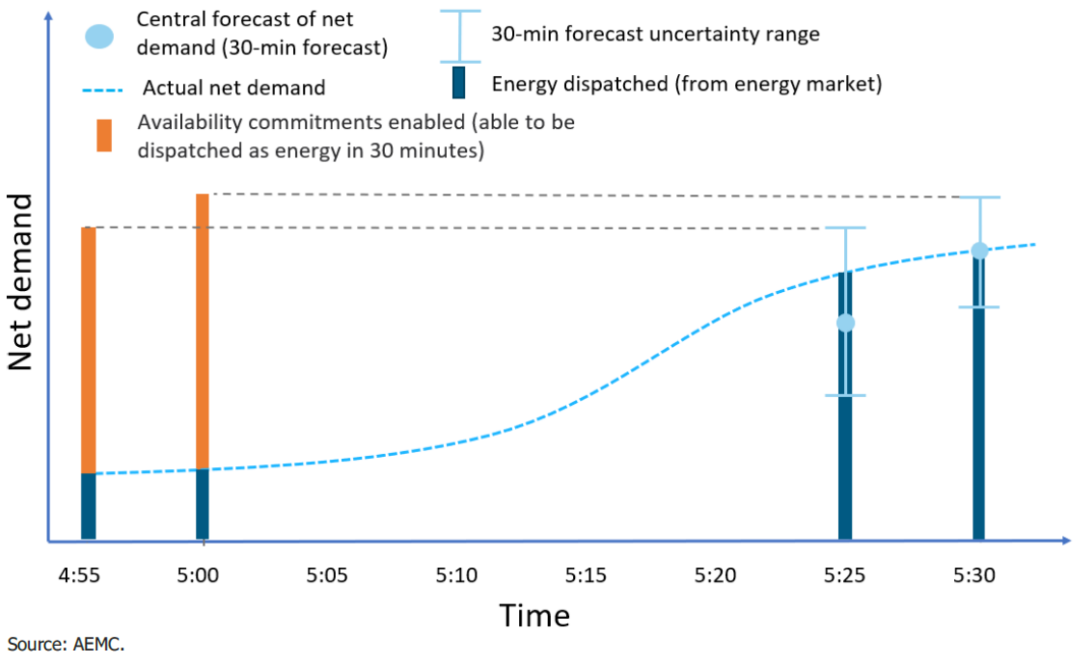


Figure 12. Working model of a co-optimised availability market (Source: AEMC)

If the capacity enabled in one dispatch interval to provide reserves is not physically capable of being dispatched as energy in the interval 30 minutes later, **it would be non-compliant** with its reserves obligation. As a starting point, the penalties should mirror those for non-compliance with FCAS obligations. This includes:

- repayment of revenue received in the Operating Reserve market, and
- a maximum financial penalty of $100,000[13].

Further consideration may be needed to determine whether there should be any **exemptions from compliance**, such as cases where non-compliance occurs due to matters outside of the control of the participant. This may place a burden and cost on participants and the AER when enforcing compliance, due to the many shades of grey involved in determining what is in and out of the control of a party (such as a safety or security issue that could have been avoided through better maintenance practices). The Commission and the AER will also need to consider whether the penalty should be a civil penalty or a financial penalty only.

In principle, **costs should be allocated to the causers of the need for the service**. The need for the service is to address uncertainty in net demand, and the causers are therefore the causers of uncertainty in net demand over a 30-minute timeframe. Conceptually, the causers are therefore scheduled and semi-scheduled generation and scheduled load[14] that generate or consume energy at a level that is different from the forecast 30 minutes ahead of that time. However, the identification of causers is not as simple as it is for regulating FCAS, for example, where the service is the need to balance energy within the dispatch interval and causers are very clearly those that deviate from dispatch instructions within an interval. Contribution to uncertainty is more difficult to determine. Accordingly, there would likely be some complexity in the further specification and identification of causers through detailed procedures to implement these arrangements.

[13] AEMO notes that a maximum financial penalty of $100,000 is low compared with the value of 100MW in the energy spot market for 5mins at the Market Price Cap, and recommends any proposed penalties be reviewed in detail.

[14] AEMO notes that unscheduled loads may also contribute to a need for the service.

A perfect allocation of costs to the causers would require individual units to pay their contribution to the cost of reserves in each five-minute period based on their real-time contribution to 30-minute uncertainty. This would be very difficult to implement and so a preferred approach is to develop causer pays factors based on contribution to uncertainty over a historical period, say the preceding quarter. This can be thought of as a more "smeared" approach to allocating costs to causers. This would be consistent with the conventional approach to causer pays for regulating FCAS.

The implementation of causer pays requirements would also require the implementation of generator self-forecasting arrangements over half-hour timeframes. Without this, the causer of the issue has no way to manage or mitigate the cost/risk they have been allocated. There is some concern that causer pays arrangements may incentivise consistent under-forecasting over 30-minute time horizons to avoid causer pays contributions, which could undermine the intent of the arrangements (to produce more accurate forecasts). This is because of the asymmetric nature of the value of operating reserves that only procure 'raise' services, not 'lower' services. Even in the future if a lower service is introduced, it is likely to be less costly than a raise service due to the greater flexibility of the fleet to meet needs for lower services. This asymmetry of value creates an incentive for participants to submit a forecast of generation output that is deliberately lower (or consumption that is higher) than what they expect to achieve to reduce the costs they incur through the causer pays cost recovery arrangements.

It is noted that these issues could be addressed and managed in the design and implementation of causer pays arrangements, we consider this aspect of the market design could be difficult to implement. This is not only due to the need to address the asymmetry issue, but also the difficulty of identifying the 'causers' of the need for operating reserves.

4 Development of an operating reserve demand curve

An appropriately constructed operating reserve demand curve allows the efficient procurement of operating reserve to appropriately address power-system risk.

4.1 Outline

The concept of a demand curve is highly applicable to the design of an Operating Reserve market. Instead of purchasing a fixed quantity, an operating reserve demand curve (ORDC) would allow the purchasing of additional reserve where and when efficient and cost-effective to do so. The amount procured is determined by the intersection of the demand-curve with the supply-curve, which is constructed via offers from participants. This demand-curve method of procurement is used in many electricity markets around the world including PJM, ERCOT, NYISO, ISO-NE, CAISO, UK, MISO, Ontario and Mexico.

There are several key elements of any possible operating reserve demand curve including:

1) the determination of minimum reserve requirements

2) how a demand curve may be efficiently formulated with respect to the underlying value of customer reliability and the probability of lost load

3) how a demand curve interacts with the intervention framework for lack of reserves

4) the activation of any Operating Reserve market

Accompanying these elements are the key considerations of when operating reserve should be purchased and the market activated (for example, for only the dispatch intervals when an LOR is forecast and/or called, for selected days, or always on), and how the procurement of operating reserve may be co-optimised with energy and ancillary service markets. These are discussed in further detail in Sections 5.1.1 and 5.1.2.

This section reviews several ORDCs in international markets before outlining the principles by which an operating reserve demand curve may be constructed, and options for various elements of the curve. It then presents a draft ORDC for the NEM (using South Australia as an example), exploring options for interaction with the intervention framework, timing of procurement and co-optimisation.

4.2 International examples of operating reserve demand curves

A number of electricity markets around the world procure operating reserve through a demand curve. FTI Consulting's final report to the ESB on Essential System Services[15] in the NEM provided an overview of the construction of the NYISO operating reserve demand curve, we include elements here for reference, alongside a review of PJM's Operating Reserve Demand Curve, ERCOT Operating Reserve, and the UK's Short-Term Operating Reserve product, noting different market structures in other jurisdictions.

NYISO

Since 2005, NYISO has operated a "nested" market design for ancillary services, in which bulk energy, frequency response and operating reserve products are co-optimised in both the day-ahead market and in real time (RT), with the potential for distinct settlement prices for each product. The market is underpinned by NYISO setting procurement targets and constructing demand curves for each service at both regional and sub-regional levels.

In relation to operating reserves specifically, NYISO procures 3 types of products: (i) 10 minute spinning reserves; (ii) 10 minute reserves; and (iii) 30 minute reserves. Prices for each reserve are determined through NYISO's construction of ORDCs, along with resource bids from market participants (which is analogous to a supply curve).

NYISO's market software evaluates RT dispatch every 5 minutes and RT commitment decisions every 15 minutes. Day-ahead market prices are set for hourly schedules and determined in the day-ahead market. RT prices are calculated every 5 minutes and settled based on the quantum of service provided in each 5 minute dispatch interval.

Prices for each 5 minute dispatch interval are determined simultaneously with energy and other ancillary service prices in RT dispatch. Shortage prices for ancillary services are taken into account in the RT dispatch engine and will set the price for a given service when the demand curve is binding.

In the NYISO market design, there are no offer prices for reserves in the RT market. RT reserve prices are determined either by the out-of-market dispatch required, given ramp constraints, to meet the reserve target or by reserve shortage prices if the reserves are insufficient to meet the target.

[15] https://esb-post2025-market-design.aemc.gov.au/reports-and-documents

When NYISO is short of reserves, the reserve shortage price will typically flow through directly into the energy price, as the dispatch of an additional MW of energy will create an additional MW of reserve shortage. This is because additional MW of energy are typically provided by generators that were providing the reserves.

In total, NYISO constructs 15 ORDCs, one for each reserve requirement, which can be broadly categorised as curves that (i) consider total requirements for a particular reserve product; or (ii) consider the location-specific requirements for a particular reserve product. For example, there are four ORDCs relating to 10 minute total reserves – three are location specific and the other one is system-wide.

In order to construct the ORDCs, NYISO establishes two key factors for each product:

- An hourly target – the target is set to equal the quantum of the product (in MW) that NYISO would procure if the cost was less than the first shortage price; and
- A shortage price per MW – this is the price that market participants would receive for providing the service when supply is less than or equal to the relevant target, thereby providing an incentive to offer reserves. NYISO is able to set different prices for different levels of shortage. For example, there are currently four different shortage prices for total 30 minute reserves, with higher prices for greater shortfalls.

In other words, the ORDC is constructed by defining shortage prices associated with shortfalls relative to reliability and operational reserve targets.

At a high level, the quantities of reserves at which steps in the demand curve occur relate to various different reliability targets. For example, NYISO is required to meet certain mandatory federal reliability targets, calculated as multiples of the largest single contingencies. These mandatory targets are responsible for the highest priced / lowest quantity steps in the curve. The steps at lower prices / higher quantities relate to reserve targets that are not required to meet federal obligations, but are for amounts of additional reserves that NYISO has decided to carry to better enable it to restore mandatory reserves following generation contingencies or other events that deplete its mandatory reserves, as well as to balance unexpected variations in net load without depleting its mandatory reserves.

The same demand curves are used to price reserve shortages in the day-ahead and RT markets, but most ORDCs rarely bind in the day-ahead market because the commitments needed to meet the reserve requirements can be made within the timeframe of the day-ahead market. The set of resources available to respond to unexpected changes in RT conditions is more limited and is more likely to result in reserve shortages of periods of time in RT operations.

Within dispatch, the market dispatch engine considers a number of constraints. This includes transmission constraints, which may result in the dispatch engine going “short” on reserves within a constrained area by dispatching reserves to meet load to avoid exceeding the transmission constraints

An additional layer of calculation is added to the process as a result of the “nested” nature of a number of the reserve targets in the NYISO market, meaning that reserves provided at some locations would meet multiple requirements, which are then reflected in the market price at that location. For example, the supply of spinning reserves also counts towards the 10 and 30 minute reserves targets, meaning that the actual price received by the provider of spinning reserves is equal to the sum of: (i) the spinning reserve shadow price; (ii) the 10 minute reserve shadow price; and (iii) the 30 minute reserve shadow price. Similarly, 30 minute reserves located in New York City meet the New York City 30 minute reserve target, the Southeast New York 30 minute reserve target, the east 30 minute reserve target and the New York Control Area 30 minute reserve target, and would therefore be paid the sum of the shadow prices. This means that if NYISO were short of 30 minute reserves within all these regions, resources providing 30 minute reserves located inside New York City would be paid the sum of the reserve shortage prices for all four of these regions.

NYISO plans to continue adjusting, extending and refining this design to meet reliability needs as the level of VRE on the system continues to rise. For example, NYISO has recently proposed to its stakeholders an increase from four to nine different shortage prices for 30-minute reserves.[16]

PJM

Like NYISO, PJM procures operating reserves using ORDCs. Historically, PJM's approach to constructing demand curves has been similar to NYISO's – using a demand curve that decreases in vertical "steps" as the supply of reserves falls further and further below the mandatory reserve requirements, until a maximum shortage price (or penalty price, in PJM terminology) is reached.

However, PJM has recently enacted a system in which the demand curves are based on a "systematic, probabilistic quantification" of load and supply uncertainties and the need for operators to take actions to ensure that these uncertainties do not cause PJM to violate the mandatory reliability requirements.

This enables PJM to value and procure reserves that are provided in excess of the mandatory minimum requirements, based on the likelihood that RT conditions will differ from forecasts, avoiding the need for operator out-of-market actions to procure these additional reserves. Specifically, PJM uses the previous three years of historical data to estimate the degree of uncertainty and net forecast error, which is then used to calculate the incremental value of reserves provided in excess of minimum requirements. This then constructs an ORDC that falls smoothly, rather than being stepped, downwards once the minimum reserve requirement has been reached.

PJM purchases three separate types of Operating Reserve: 10-Minute Synchronized Reserve (SR), 10-Minute Primary Reserve (PR), and 30-Minute Reserves.

Twenty-four different ORDCs are modelled per reserve, one for each of the four seasons and time-of-day blocks (divided into six 4hr intervals). [17]

ERCOT

In 2014, the Energy Reliability Council of Texas (ERCOT) implemented a new Operating Reserve market, with a demand curve, which would have the effect of automatically raising wholesale prices in the real-time energy market as available operating reserves decrease.

The ORDC functions as a "price adder" curve at times of scarcity and is based on the level of increasing risk of a cascading outage (Loss of Load Probability, or LOLP) and the potential consumer impacts associated with an outage (Value of Lost Load, or VOLL).

ERCOT continually monitors the availability of operating reserves to support grid reliability. As reserves decrease, the possibility of an outage increases. As the LOLP goes up, the ORDC will increase accordingly. When operating reserves drop to specific threshold (2,000 MW or less at implementation), the ORDC automatically sets the price to the established VOLL ($9,000 per megawatt-hour (MWh)). This is higher than the wholesale energy market price cap of $5000/MWh.

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[16] FTI Consulting Report to the ESB – Essential system services in the NEM, 2020

[17] https://pjm.com/-/media/committees-groups/committees/mic/2021/20210407/20210407-mic-info-only-operating-reserve-demand-curvesordc.ashx

That is, with implementation of the ORDC, the total 'energy + reserves' price can rise to $9,000 per MWh, but the adder will not result in energy prices higher than the VOLL.[18]

UK-NGESO

The procurement of STOR has evolved over time at NGESO's discretion since its introduction in 2007. Initially, tenders were for contracts up to two years ahead, but then updated to procure long-term STOR contracts (up to 10 years) in order to incentivise potential investors to participate. It was thought that long-term contracts would allow potential providers the ability to tender to receive a long-term revenue stream "*where significant investment is required to offer a service, to more efficiently recover capital expenditure*".

NGESO have since discontinued these long-term contracts in of favour of short-term STOR contracts that can last up to two years.[19]

4.3 Principles for the development of an operating reserve demand curve

AEMC's 2020 System Services Consultation Paper underscored the importance of the National Electricity Objective as the primary overarching objective of any market change to the NEM. In addition to this, AEMC provided clarification of system services objectives:

- Promoting efficient operation – achieve an optimal combination of inputs to produce the demanded level of the service at least cost.
- Promoting efficient use – allocating resources between the provision of multiple services to achieve an efficient mix of overall service provision.
- Promoting efficient investment – to continue to achieve allocative and productive efficiencies over time.

For the ESB Post-2025 program, FTI identified several broad principles guiding international development of markets for essential power system services[20] including:

i) operational efficiency

ii) provision of efficient investment signals

iii) appropriate risk allocation and cost recovery

iv) proportionate procurement

v) transparency

vi) adaptability, and

vii) no undue discrimination.

Following these principles there are key design parameters that are applicable to any market procurement mechanism:

a) co-optimisation

[18] https://hepg.hks.harvard.edu/files/hepg/files/ordcupdate-final.pdf

[19] FTI Consulting Report to the ESB – Essential system services in the NEM, 2020

[20] FTI Consulting Report to the ESB – Essential system services in the NEM, 2020

b) centralised vs de-centralised procurement

c) target setting

d) geographic granularity

e) procurement timeframe and

f) resource commitment

The NEO, AEMC's objectives, and the above principles and design parameters are used in the following section to influence, guide and evaluate options for the development of a procurement mechanism for operating reserve and methods by which to construct a demand curve. Additionally helpful is clarity on the costs of the counterfactual – if a market is needed but not implemented, the cost impact to customers provides a guiderail on the value of implementation.

In broad terms, the demand for operating reserve is based on the need to meet both expected ramp and unexpected ramping needs. Expected net ramping is the ramp capacity required to meet forecast demand; additional unexpected net ramping accounts for the uncertainty around the net load forecast. This uncertainty is not a static quantity and is expected to change according to network conditions, weather, and participant offers.

An Operating Reserve Demand Curve (ORDC) can be developed to reflect the economic value of reliability: the marginal value of reserves to avoid involuntary load shedding. This may be formulated through the probability of lost load (POLL) times the value of lost load (VOLL).

4.4 A draft operating reserve demand curve for the NEM

4.4.1 Considerations for construction

A potential approach to developing an ORDC includes the following steps:

1. Document Potential Out-of-Market Actions and "Trigger Thresholds"

Identify approximate MW trigger levels or thresholds of operating reserves at which point AEMO may intervene in the market to shed load, engage in voltage reductions, direct non-market unit commitments, or other actions. The trigger levels should also be tied to a specific forward timeframe in order to ensure that the ramping product is afforded an in-market opportunity to attract the needed supplies prior to any out of market action being taken.

2. Identify Minimum Reserve Requirements

If there is a minimum quantity of reserve that AEMO must carry at all times, then this would be defined as the "minimum reserve requirement" point on the ORDC. The maximum price paid for ramping reserves would be an Operating Reserve market price cap at this minimum quantity, set at a level to reflect that AEMO will engage in involuntary load shedding rather than falling below this minimum reserve requirement. Note that this minimum reserve requirement only refers to the minimum ramping reserves, it does not include FCAS which is assumed will be maintained even during load shedding events but that are procured separately.

3. Establish Appropriate Value of Avoiding Out-of-Market Actions

For each type of out-of-market action that AEMO may take (such as exercising RERT), establish the appropriate value to pay for avoiding these actions. The primary value is the value of customer reliability

(VCR), which in other markets is synonymous with the market price cap. In the NEM, for an Operating Reserve it may be appropriate to use the market price cap as a proxy value in lieu of the full VCR to maintain consistency with energy and FCAS price formation, and to allow a single nationally consistent value to be applied. For other lower-cost interventions such as out-of-market unit commitments the cost of the action may be estimated and used as the basis for value, potentially with an additional cost adder to signal the preference to use in-market solutions rather than out-of-market actions.

4. Estimate the Probability of Each Action as a Function of Reserve Quantity

For each timeframe and location, conduct a probabilistic analysis of the likelihood of engaging in each out-of-market action as a function of the reserve MW. This analysis would consider the uncertainty distribution around net load across the ramping timeframe. The analysis would estimate the incremental likelihood that holding 1 MW of additional ramping reserves would help to avoid load shedding or other actions. The analysis is fairly involved and requires a number of assumptions and NEM-specific data on net load variations, especially forecast error.

5. Downward-Sloping ORDC Shape

The downward sloping shape of the ORDC for each product would be calculated as the probability of avoiding incremental out-of-market actions by holding 1 MW of additional reserves, times the societal cost of engaging in such actions.

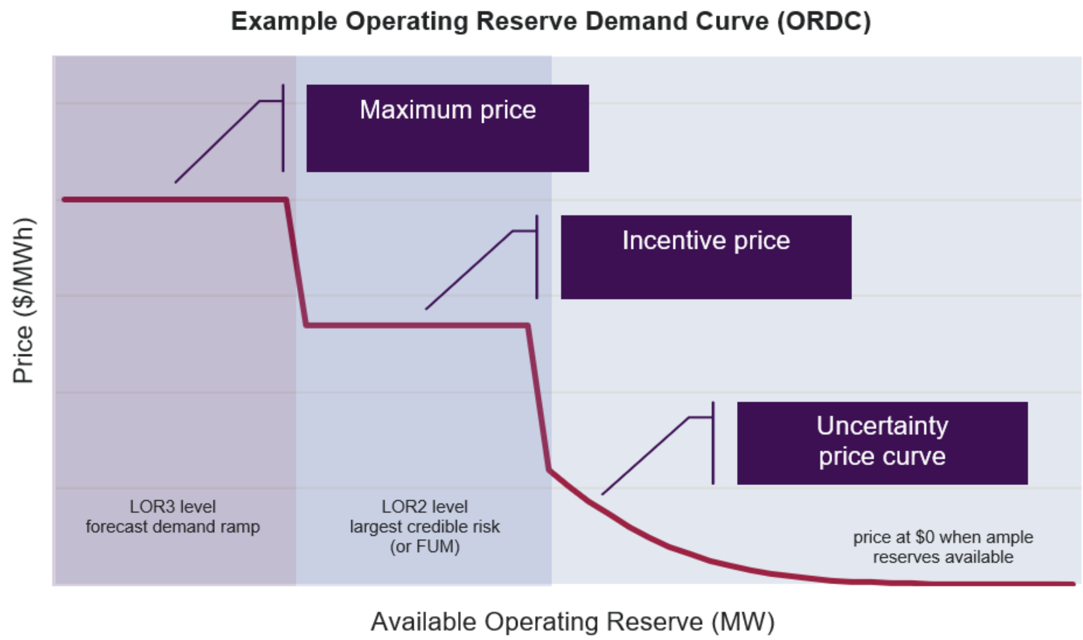


Figure 13 Conceptual ORDC reflecting: a maximum price for meeting the minimum reserve requirement (to avoid out-of-market actions), and a downward sloping shape reflecting the incremental probability of avoiding out-of-market actions. The maximum price is set to zero where available operating reserve is plentiful.

6. Translate the Curves into a Formula that Can be Updated in Real-Time Operations

Based on an analysis of the ORDC across seasonal, daily, and other relevant patterns, translate the ORDC into a formula that can be updated continuously as a function of data that will be available in real-time operations. At a minimum we expect that the formula will be a function of the expected net ramp, which will translate the curve left/right. The value is also a function of forward timeframe, time of day, and season. The parameters of these formulas would be updated on an annual basis (if not more frequently) and published in order for participants to form their own view on future market value. The smooth ORDC that is developed in this analysis may need other adjustments such as conversion into a step-wise function for implementation.

The primary purpose for developing and implementing the ORDC is to reflect an in-market value-based means of paying for ramping reserves that are needed for system security so as to avoid out-of-market actions that would otherwise be taken to maintain. However, the ORDC will contribute other benefits to the system as well including to support efficient scarcity pricing that aligns with system needs, incrementally contribute to investment signals for reliability, and incentivizing emerging resources to become more dispatchable.

In the following subsections, we consider the application of these design elements for the NEM.

4.4.2 Out of market actions and trigger thresholds

A lack of reserve condition (clause 4.8.4 of the NER) is when AEMO determines, in accordance with the reserve level declaration guidelines, that the probability of load shedding (other than the reduction or disconnection of interruptible load) is, or is forecast to be, more than remote.

The critical trigger thresholds for AEMO intervention for reserves in operational timeframes is the Lack of Reserve Levels 2 and 3, issued when reserves fall below the greater of the largest credible contingency or forecast uncertainty margin (LOR2) or at or below zero (LOR3). If at this point AEMO considers that the market has not responded to published information by making sufficient reserves available, it has a range of tools to intervene or act out of the market, including activating RERT services[21].

As discussed in Section 2.2, this can occur through RERT contracts when available or through the RERT panel and the automatic Invitation to Tender approach.

An objective of an Operating Reserve market is to reduce the need for out-of-market intervention due to lack of reserves in operational timeframes. The key benefit would be to procure Type 1 and 2 RERT services (with activation times of less than < 30mins) *in-market*, instead of through out-of-market contracts that are manually administered.

By incorporating Operating Reserve into dispatch and pre-dispatch processes it is envisaged that there would be a lower occurrence of LOR conditions due to the additional visibility, commitment and confidence in reserves materialising (see Section 5.1).

It is expected that following implementation of an Operating Reserve market, Type 1 services would be maintained (and activated post-contingency as is currently the case), with other RERT services activated in the event reserves from the Operating Reserve market have not materialised as forecast.

A Lack of Reserve Level 3 (LOR3) is issued when the forecast reserve for a region is at or below zero. That is, insufficient supply is available to meet the expected demand ramp. At this point further interventions (including load shedding) may proceed as per the current intervention framework.

[21] SO_OP_3715 Power System Security Guidelines

4.4.3 Minimum reserve requirements

The minimum reserve requirements for an ORDC are most efficient if informed by the trigger thresholds for out of market actions. That is, if the operator is required to intervene due to uncertainty in demand/supply of reserves (often resulting in effective energy prices above MPC), then an efficient operating reserve would prevent this intervention and provide certainty to the operator at lower cost than the intervention.

This consideration suggests the minimum reserve MW requirement should be sufficient to cover the level of reserves for which AEMO would pre-activate RERT or otherwise intervene in the energy market. Given the amount of Operating Reserve will be procured 30 minutes ahead, this level of reserves would be dynamic, and include the expected demand ramp and the LOR2 threshold for each region.

We employ the LOR2 level in examples below and through the rest of the document, noting that with a redeveloped ST-PASA the calculation of the Lack of Reserve requirement for AEMO intervention is proposed to change to consider forecast uncertainty more directly. As a result, the appropriate minimum reserve requirements will be set dynamically according to STPASA outputs. This formulation should be consulted with stakeholders and regularly reviewed.

In relation to the working model (see Section 3), the current minimum requirement aligns with procuring sufficient reserve to meet the expected net demand ramp, and the LOR 2 minimum requirement which considers a forecast uncertainty margin. This alignment with LOR levels will likely change with a redeveloped ST PASA.

4.4.4 Procuring expected and unexpected ramp

It is proposed that an offer reflects the availability of a resource above what it is currently being dispatched. A critical design feature of procuring reserve is that the amount of reserve to procure must equal both the 'expected' ramp and any additional amount for uncertainty (unexpected ramp). If only the 'uncertainty' component was procured then there would be inadequate confidence that the total availability in 30 minutes will be sufficient to meet both the expected ramp *and* any uncertain ramp – that is, the procured reserve might be all 'used up' for the expected ramp, resulting in risk of insufficient reserve.

To procure only the 'uncertainty' component, then this reserve must be held out of market – negating the benefit of the proposed design. The corollary however is that since the market is able to see what the expected ramp will be, the cost of operating reserve to meet this expected ramp should be very low, if not negligible. Further, this approach is consistent with the principle that resources that are expected to ramp (based on pre-dispatch prices) over the procurement period are eligible to offer reserves. This assumption should be discussed with stakeholders and could be tested through modelling as part of a detailed design phase.

Energy offers in pre-dispatch above the central forecast of demand within a certain price band may be considered an 'offer of OR at zero price' for the purpose of constructing the supply curve. This may support the expectation if there is very significant amount of expected reserve provided through energy pre-dispatch (and little risk of insufficient operating reserve), that the operating reserve price would remain low.

4.4.5 Maximum reserve prices

The avoidance of intervention is also helpful to guide the timeframes of procurement of reserve (discussed below), and the price cap for reserve. There are various approaches to setting the maximum price of reserves (the operating reserve price cap), for example through reference to the NEM Market Price Cap (currently $15,500/MWh), the Value of Customer Reliability[22] (VCR), or the costs and frameworks for intervention. The

[22] For reference, the AER currently estimates VCR at $31,440/MWh for residential customers in South Australia

following matters should be considered in the implementation of any of these approaches, due to the possibility of participants receiving very high prices for providing operating reserves, and energy in later intervals:

- The interactions of OR with the reliability settings
- If OR prices were allowed to be greater than MPC, the potential interaction of OR with constraint violation penalties
- If OR prices were allowed to be greater than MPC, the implications for co-optimisation given bids in existing markets are capped

As a result, AEMO recommends that the methodology and curve parameters be detailed in a Procedure that allows periodic review and consultation with stakeholders.

Three specific options, and associated recommendations are discussed in more detail in coming sections. These are i) approaches referencing the Value of Customer Reliability and the Market Price Cap, ii) using 'incentive pricing' to bring resources online, and iii) using a combination pricing approach.

Value of Customer Reliability (VCR) and Market Price Cap (MPC) based

An Operating Reserve Demand Curve can support the valuation of reserve such that the sum of reserve and energy prices theoretically reflect the Value of Customer Reliability. That is, the maximum price of energy and reserve combined may equal the VCR, above which price load-shedding would theoretically be more preferable. In this approach, the economically efficient maximum value of operating reserve would be (VCR-MPC), but whilst there are theoretical justifications for referencing the Value of Customer Reliability, in practice there are challenges that arise from the various values of VCR within and across regions according to market customer-type. There may be additional unintended consequences if the OR market had a higher market price cap than energy and FCAS markets.

With an example value for the VCR of a residential customer in South Australia of $31,440/MWh, this approach would set a maximum OR price of VCR-MPC = $15,940/MW. The proximity of this to the current energy MPC of $15,500/MWh allows the possibility of tying the maximum OR price cap to the energy MPC to offer a more consistent value that i) avoids the discrepancies of jurisdictional based estimations of VCR, and ii) any perception that an OR market may represent more attractive remuneration than energy and FCAS spot markets. AEMO proceeds with constructing an example ORDC using the energy MPC as the price cap for the Operating Reserve market, with recognition that 2*MPC is currently close to VCR. That is, a participant may receive a maximum revenue close to the VCR if the energy and OR markets are at their respective caps at MPC, though this would need to be reviewed if VCR or MPC were to significantly change. The intention would be for RERT to be used only if there is insufficient market response, but to note, this cap would represent an economically efficient value only if there was certainty of lost load and no out-of-market actions (such as activation of RERT) were taken before load-shedding.

Further consideration may be given to constructing the maximum price point through the probability of exceeding the demand forecast, discussed further below. The LOR3 threshold is based on the P50 forecast of operational demand and used to inform out-of-market actions before forced load-shedding occurs. There may be scope to apply probabilities to the maximum price formulation to achieve more efficiency, and this should be considered with stakeholders in the future, but we proceed here for this option with VCR-based pricing applied up to the LOR3 threshold.

Incentive based pricing

Sections of the Operating Reserve Demand Curve may also be constructed such that quantities align with intervention processes (e.g., RERT), but prices reflect a policy choice rather than being informed by VCR, as would be theoretically optimal. This report calls this approach 'incentive pricing'.

For example, if it was desirable to give in-market resources an opportunity to earn revenue under the same conditions as RERT providers, but not desirable for the ORDC to be priced at (VCR-MPC) for quantities up to the largest credible risk (i.e., the RERT intervention threshold), then incentive-based pricing may be appropriate.

The actual price chosen for such a section of the ORDC could be informed by related policy settings, such as intervention thresholds and reliability settings, or empirical matters such as operating costs of those resources (e.g., fast start generators) that would ideally be brought online. Figure 16 and others in this report, have illustrated incentive pricing at $8,000/MWh, however this number is purely indicative.

This approach would benefit from regular review following analysis of market performance and behaviour, especially given potential movements in costs and their technology basis. Of particular importance would be the analysis of spot-market prices for the intervals when the Operating Reserve market is activated, or clearing at non-zero prices (e.g., during LOR2 events).

Combination stepped pricing approach

A combination of the above two approaches allows a demand cure that reflects the value of customer reliability (though set at MPC) for reserve levels below the LOR3 threshold (where load shedding is expected), incentive pricing from this level to below the LOR2 threshold (where market interventions would be required), and uncertainty curve pricing beyond.

AEMO's preference is for this combined pricing approach, with ability to periodically adjust and review (below determined maximum values [e.g., max(incentive, MPC)]) according to current market conditions. An example is provided below with forecast demand of 200 MW (the LOR3 threshold for reserves) and the largest credible risk of 220 MW (LOR2 threshold for reserves: forecast demand [200 MW] + LCR [220 MW] = 420 MW). The ability to adjust the curve will be critical as the nature of participant interaction with the Operating Reserve market and intervention framework changes according to market conditions. There is further potential for gradual introduction and testing of an ORDC using lower pricing, to be reviewed alongside its impact to interventions before gradual adjustment towards greater market efficiency.

Further considerations

A key factor of emerging uncertainty in the demand-supply balance of the power system arises from participant positioning in being online and available. If the possibility of receiving the current Market Price Cap (through energy dispatch) is insufficient to incentivise the provision of availability, it is unclear what additional revenue would support availability. For this reason, a real-time 'Scarcity Price Adder' to energy spot prices is not preferred over a firm commitment ahead of time to provide Operating Reserves through an obligation of additional offers. This analysis also supports the value of not solely relying on the energy spot price and/or operating reserve.

Providers will, by necessity, participate in the energy market as well as OR, and will therefore receive energy prices when dispatched (as well as operating reserve prices when enabled). An operating reserve with robust compliance may provide a valuable tool for the system operator in ensuring sufficient availability in the face of uncertainty of net demand and/or supply, but there are many and varied risks in managing the power system and the ability to intervene, e.g., through RERT, supports operator confidence and system resilience.

4.4.6 Probability of lost load

Following on from the consideration of minimum reserve requirements and prices, an operating reserve demand curve may also reflect the probabilistic value of reserve in responding to forecast uncertainty. The probability of lost load is an expression of the uncertainty of generation being able to meet demand. There are many contributing factors to this uncertainty including forecast uncertainty of VRE, the uncertainty of participant availability, dispatchability of scheduled resources, and forecast uncertainty of demand.

It is difficult to quantify the uncertainty of participant availability, but the uncertainty of net demand (Demand – VRE) is readily quantifiable (Figure 14). Using the South Australian Summer of 2019-20 as an example, we investigated 30-minute forecast errors for both demand, solar and wind for all dispatch intervals between 2-6pm. The probability curves (and resulting ORDC) may be similarly calculated for all regions, seasons and periods-of-the-day.

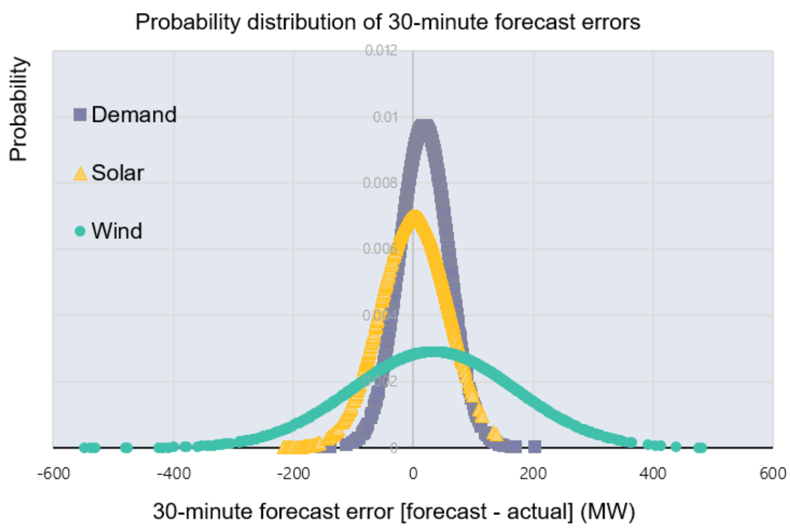


Figure 14. Probability distribution of forecast errors from VRE and demand, South Australia Summer 2019-20, 2-6pm.

Summing the data points of forecast error individually (Demand Forecast Error – [Solar Forecast Error + Wind Forecast Error]), we can obtain a probability distribution that the forecast error will be higher than any particular level of available reserve (Figure 15).

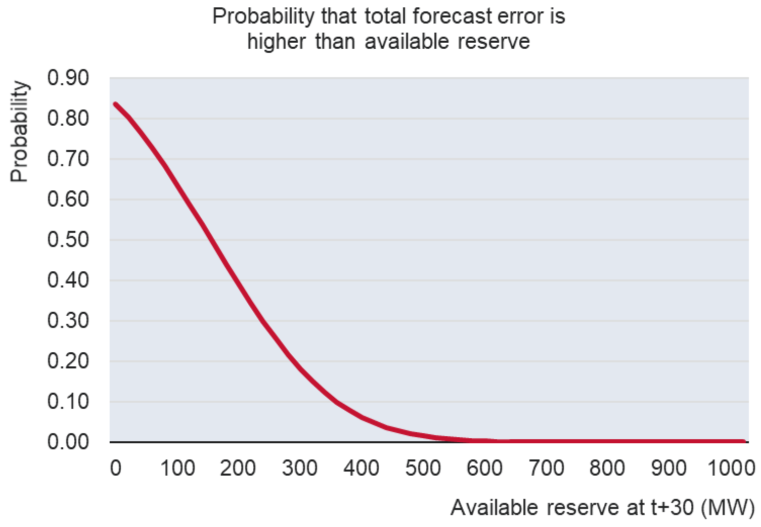


Figure 15 Summing forecast errors in demand, wind and solar allows calculation of the probability distribution that the total forecast error is higher than reserve, South Australia Summer 2019-20, 2-6pm.

To note, this is a static calculation from a defined historical period and used to illustrate how historical forecast errors may inform probabilities of lost load. In practice, the historical period for reference may be adjusted periodically or dynamically and incorporate other sources of uncertainty and forecast error.

Following the redevelopment of ST-PASA, the calculation of uncertainty margins may provide a more direct and dynamic representation of reserve requirements based on a more complete and up-to-date consideration of power system risk from demand, supply and network conditions. This will include the aforementioned sources of uncertainty – load, wind and solar uncertainty – as well as uncertainty in the maximum availability of scheduled generation.

4.4.7 A draft operating reserve demand curve for the NEM

The probability distribution, once calculated, allows an efficient construction of an Operating Reserve Demand Curve for the NEM. Using the two options for the valuation of reserve (VCR and Incentive Prices) and using South Australia summer 2-6pm as an example, we can create an indicative curve to support discussion and stakeholder consultation.

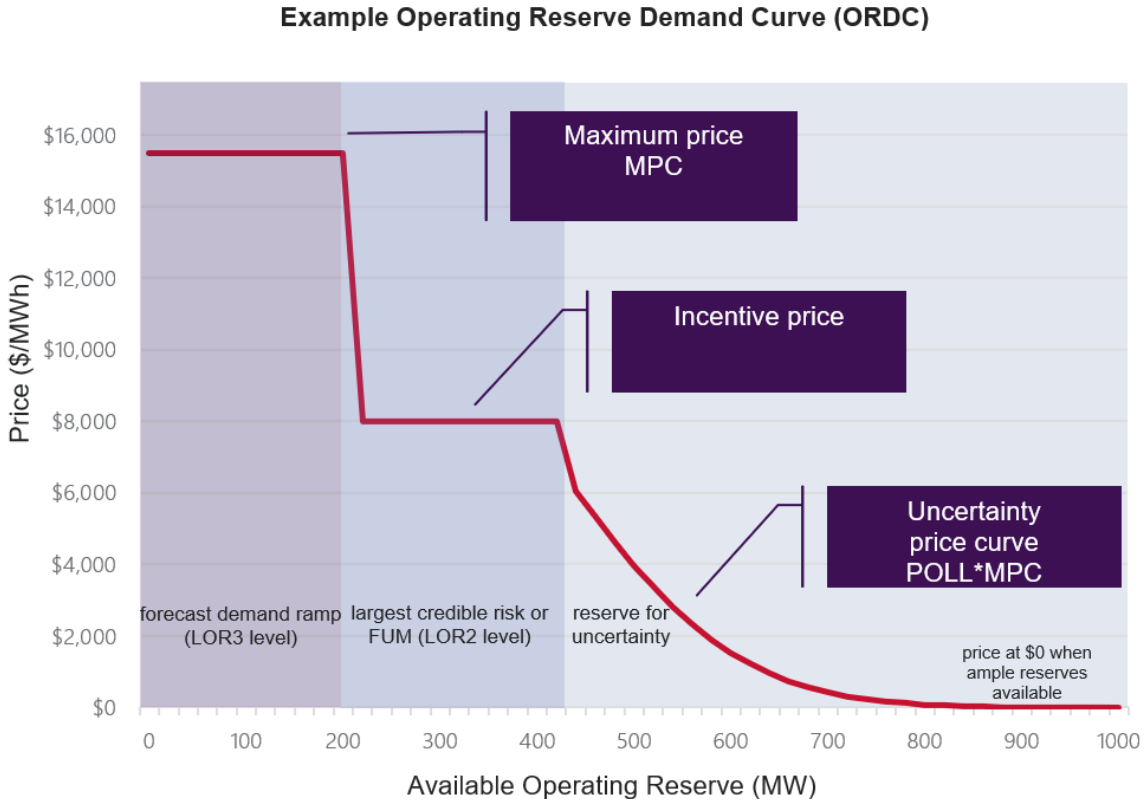


Figure 16 Example Operating Reserve Demand Curve, using South Australia as an example region, with an assumed forecast demand ramp of 200 MW, a largest credible risk of 220 MW, and historical forecast uncertainty from SA summer 2091-20 from 2-6pm to inform the curved section. The price structure reflects i) the minimum reserve requirement to avoid lost load, ii) incentive pricing to bring reserves in-market, and iii) and a curve to reflect the incremental value of avoiding out-of-market actions according to the uncertainty and the probability of lost load.

This curve assumes a central demand forecast of a 200 MW ramp with prices set at MPC ($15,500), an Incentive Price of $8,000 for the provision of reserve to the LOR2 threshold set by an assumed largest credible risk of 220 MW, and a curve beyond this set by MPC*the Probability of Lost Load (Figure 16).

AEMO underscores this is an example indicative curve to support consideration of how an ORDC may be constructed and notes detailed stakeholder consultation is required before progressing to detailed design. AEMO also underscores the recommendation that the methodology and curve parameters be detailed in a Procedure that allows periodic review and consultation with stakeholders.

Operating Reserve Demand Curve formulation

x-axis: MW

y-axis: $/(MW_offers_at_t+30mins_above_currently_dispatched_energy)

ORDC = { MPC, 0 ≤ x < Expected ramp (P50);

Incentive price, Expected ramp (P50) ≤ x < Expected ramp (P50) + LCR;

Uncertainty price curve (y=POLL*MPC), Expected ramp (P50) + LCR ≤ x;

$0, when ample reserves are available (e.g., when POLL approaches 0) }

MPC: maximum price cap

POLL: Probability of Lost Load

Expected ramp (P50): the expected ramp in t+30mins. (Forecast Operational Demand (P50) at t+30mins – Current Operational Demand t=0). The LOR3 threshold is met if forecast availability falls below this amount. If demand is not expected to ramp in t+30mins, the expected ramp is set to zero.

LCR: Largest credible risk or FUM. The LOR2 threshold is met if forecast availability falls below this amount.

Further detailed design of an Operating Reserve market should consider whether and how interconnectors are treated as a source of available operating reserve, and any effect this may have on the ability to cover broader power system risks.

The Operating Reserve price and quantity is then set by the intersection of the supply curve (the offer stack) with the demand curve. The value of the curved part of the ORDC is that it allows the procurement of additional reserve to appropriately manage system risk above minimum requirements (according to the probability of lost load), where efficient to do so.

As for the calculation of the probability distribution of Section 4.4.6, this example ORDC is a static calculation from a defined historical period of forecast error and used for illustrative purposes. In practice, the uncertainty segment of the curve would be adjusted periodically or dynamically and could incorporate other sources of uncertainty and forecast error. As above, following the redevelopment of ST-PASA, the calculation of uncertainty margins may provide a more direct and dynamic representation of reserve requirements to inform the construction of the demand curve.

However it may be constructed, the calculation of an Operating Reserve Demand Curve would benefit from further detailed design work, consultation, open publication and regular review, with consideration of appropriate governance for key market design parameters (e.g., set through the Reliability Panel).

5 Reserves obligation and interaction with dispatch processes

Operating reserves would be a new market ancillary service. Interactions with dispatch processes and the intervention framework require careful consideration.

5.1 Procurement timing considerations and interaction with the intervention framework

In this section we explore considerations of timing and how an operating reserve would interact with a future intervention framework, both of which require careful consideration. There are several factors that make an operating reserve especially complex compared to other ancillary services, including intertemporal considerations, the nature of co-optimisation, integration into the NEM Dispatch Engine (NEMDE) and relationship with existing intervention frameworks. There are two key timing considerations to consider with an Operating Reserve market for the NEM – i) the 'ahead-ness' of the availability product, and ii) the timing of market activation.

5.1.1 Ahead-ness of the availability product

AEMO notes that the appropriate 'ahead-ness' of procurement of an Operating Reserve market requires detailed consideration alongside the nature of reserve obligation and interaction with intervention frameworks currently under redevelopment. For an Operating Reserve market that procures "additional-availability-in-ahead-timeframes" (as per the working model) there are trade-offs between i) participant management of future availability and price risk, ii) uncertainty margins associated with longer ahead timeframes and consequences for the amount of reserves that may need to be procured, and iii) system operator visibility of availability and opportunities to intervene if required.

Participant management of future availability

An availability product places a value on a participants' commitment to offer additional capacity in a future dispatch interval. The shorter the ahead timeframe, the lower the risk to participants in both i) assessing their own value of their future availability, and ii) committing this availability. Considerations of how this risk might be assessed, managed, or hedged should be explored in detailed stakeholder consultation.

Of further relevance is the timeframe for which offline resources (such as gas units from cold-start and demand response) might be able to come online and be available, for storage resources to appropriately manage states of charge to provide reserve, or for semi-scheduled resources to manage firming. Any market should be technology neutral where possible but detailed stakeholder consultation will support design to allow efficient participation from the widest possible range of resources.

Uncertainty margins with longer ahead timeframes

Forecast uncertainty increases with greater forecast horizons. That is, the uncertainty margin 4 hours ahead (at say the 95th percentile) is greater than that for 30 minutes ahead at the equivalent confidence level. An availability product with longer ahead timeframes may require greater amounts of reserve to be procured, or careful consideration of the level(s) of uncertainty a reserve product is intended to cover. These considerations may be reflected in the formulation of the demand curve and should be explored in detailed stakeholder consultation.

System operator visibility and intervention capability

An objective of an Operating Reserve market is to increase operator confidence that adequate reserves will be available in real time during times of forecast uncertainty, hence reducing the need for intervention for reserve, but the option to intervene must remain available to maintain system security. Intervention to secure sufficient reserves may occur through the activation of RERT and the timeframes through which this happens is of importance to any design of an Operating Reserve market.

A critical benefit of an Operating Reserve market is i) the visibility it can provide in pre-dispatch of available operating reserve, and ii) the certainty of availability once operating reserve has been dispatched. The timeframes for both are different, with the benefits of visibility occurring throughout the period of market activation (discussed below), and the certainty of availability relying on the 'ahead-ness'.

The more 'ahead' any commitment of availability is, the greater confidence it gives to the system operator that adequate reserves will be provided. The Short-Term Operating Reserve (STOR) product for the UK National Grid ESO, for example, procures reserve at 5am for the following day (0500hrs – 0500hrs)[23], though for a different ahead-market structure.

A critical question is: what is the shortest amount of ahead-ness of an operating reserve product that provides i) market participants with an opportunity to respond as well as ii) AEMO intervention for system security where a response does not materialise?

Relevant timescales are set by the Latest Time to Intervene and the latest time to pre-activate RERT services – which may vary according to market conditions and RERT availability. Under NER clause 4.8.5A(a) and (c), AEMO must notify the market of any anticipated power system security or reliability issue, and the latest time for market response before AEMO would need to intervene.

Assuming that AEMO had notified the market of an anticipated power system security or reliability issue, a timeframe of thirty minutes is the absolute minimum that would still allow the activation of Type 1 RERT services (defined as reserves that can be exercised in < 30 minutes, including pre-activation and activation) if insufficient operating reserve was offered, though may still leave residual risk to the system operator in being able to intervene to maintain system security and reliability. A 30-minute ahead product also has a natural alignment with AEMO's obligations to return the system to a secure state within 30 minutes of a single credible contingency[24]. A 30-minute product would directly translate this obligation into value in a market, via the 'minimum reserve requirement' section of the ORDC described in section 4.

Nonetheless, a timeframe of 1hr or greater would additionally support the pre-activation and activation of Type 2 RERT services (reserves that have a sum of pre-activation time and activation time => 30 minutes and an activation time < 30 minutes).

Following detailed consideration of interaction with dispatch processes, and only if strict compliance measures were in place, AEMO's preference would be for a 1-4 hour Operating Reserve mechanism that allows manual intervention to ensure adequate reserves if required, By giving resources obligations to provide headroom sooner, there is greater confidence in future delivery of energy in timeframes relevant to intervention decisions, and

[23] https://www.nationalgrideso.com/industry-information/balancing-services/reserve-services/short-term-operating-reserve

[24] NER 4.2.6

additional ability to increase availability to bring units online. In contrast, under a 30-minute product, intervention decisions must be made entirely on the basis of expectations of participant behaviour.

AEMO acknowledges that intervention decision timing varies according to the resources available through RERT and via directions, and so even a 4-hour product is not necessarily sufficient to cover all scenarios. We also acknowledge there are potential costs and risks of a longer (i.e., >4 hr) timeframe product under this working model. AEMO therefore believes there is merit in considering other product models that could firmly commit resources to ensure adequate reserves over the operational horizon more broadly.

AEMO again underscores the importance of detailed stakeholder consultation for detailed design, but proceeds in this report on the basis of a 30-minute product.

5.1.2 Operating Reserve market activation

There are design options for when an Operating Reserve market would be activated:

1. **Only during periods where market intervention would otherwise occur.**
   - Under this option the Operating Reserve market is only activated when there is an actual or forecast LOR and is solely aligned with the objective of reducing market intervention. Activating the Operating Reserve market sufficiently ahead of the latest time to pre-activate RERT services, to allow consideration of whether there will be sufficient reserves made available before intervention, may be required. The Operating Reserve market would then be active until the LOR condition had been cancelled. To note, there is no intent for this or other design options for an OR market to stop normal energy market bidding and operation.
   - Considerations for such an option include i) the level of preparedness and ability for Operating Reserve market participants to respond quickly when the Operating Reserve market is activated (sufficient to avoid alternative mitigation through RERT), and ii) the need for rules around activation/deactivation if forecast LOR changes.
   - This approach may align more with NMAS frameworks, such as that which is being considering under the Operational Security Mechanism Rule Change under the NMAS option[25]. Alternatively, and potentially equivalently, the ORDC may be constructed to be zero when reserves either in the energy market, the Operating Reserve market, or both, are forecast to be significantly more than sufficient (e.g., when the probability of lost load approaches zero, reserves exceed four times the size of the largest credible risk, or another more appropriate metric). This would have the implicit effect of market activation only during times of forecast low reserve.
2. **The Operating Reserve market is activated on days where reserve is at risk of being low**.
   - The Operating Reserve market would be activated for the entire trading day each time, giving Operating Reserve market participants longer notice than Option 1. A day selection criteria and methodology would be required to establish such an arrangement. It may be beneficial to allow flexibility with such a methodology, to support operational awareness and/or obtain early visibility of available reserve capacity. The timing of market activation may also benefit from regular review as participants become more familiar with Operating Reserve market activation and operation. Consideration would also need to be given to the potential for short-notice activation if a risk of low reserves unexpectedly arises.
3. **The Operating Reserve market is always active**

[25] See https://www.aemc.gov.au/rule-changes/operational-security-mechanism

- This option aligns in concept with contingency FCAS markets, in that contingency FCAS is always enabled in case it is required. This option attributes direct economic value to the provision of reserve services, thus providing a clearer incentive for investment in flexible dispatchable resources. This option also supports greater power system resilience in procuring greater reserves than current minimum levels, when efficient, noting that this approach would support the provision of reserve on unexpected days where it may be most needed.

  As discussed for Option 1, whilst the market may be always active, the price may be zero when ample reserves available. This option may also support development of operational capability to react to OR signals – particularly important for small & demand side resources.

This technical advice has been prepared on the assumption of Option 3. Whilst AEMO does not provide an explicit recommendation, based on an expectation of zero or very low pricing at times of plentiful reserve this option may provide a benefit of reduced manual operation for participants with Operating Reserve market participation more readily adopted into BAU processes as for other ancillary services.

5.1.3 A demonstration of intervention interactions

To support analysis of how an Operating Reserve market may work in practice, we explore a hypothetical LOR2 event with and without an Operating Market in place (Figure 17). This hypothetical event is a typical representation of recent LOR2 events and how RERT was pre-activated and activated in practice as a result. It assumes:

- A forecast LOR2 for 17:00-17:30 under the current framework
- There are no Long/Medium/Short-notice contracts in place
- There is availability of all of Type 1, 2, and 3 Services on the Short-notice RERT Panel, but insufficient depth of Type 1 and 2 Services to meet reserve requirements.
- Available Type 3 services have a pre-activation time of 2.5hrs and are determined by AEMO to be the most suitable and cost effective to meet RERT requirements, taking into account interconnector limits.
- There are no further generation or network options available to relieve the reserve situation

During low reserve conditions, an Operating Reserve market would help bring reserves online, avoiding the need for declaration of actual LOR2 conditions with associated intervention costs. If sufficient reserves do not materialise, RERT may still be activated though costs would need to be considered in relation to the value of customer reliability.

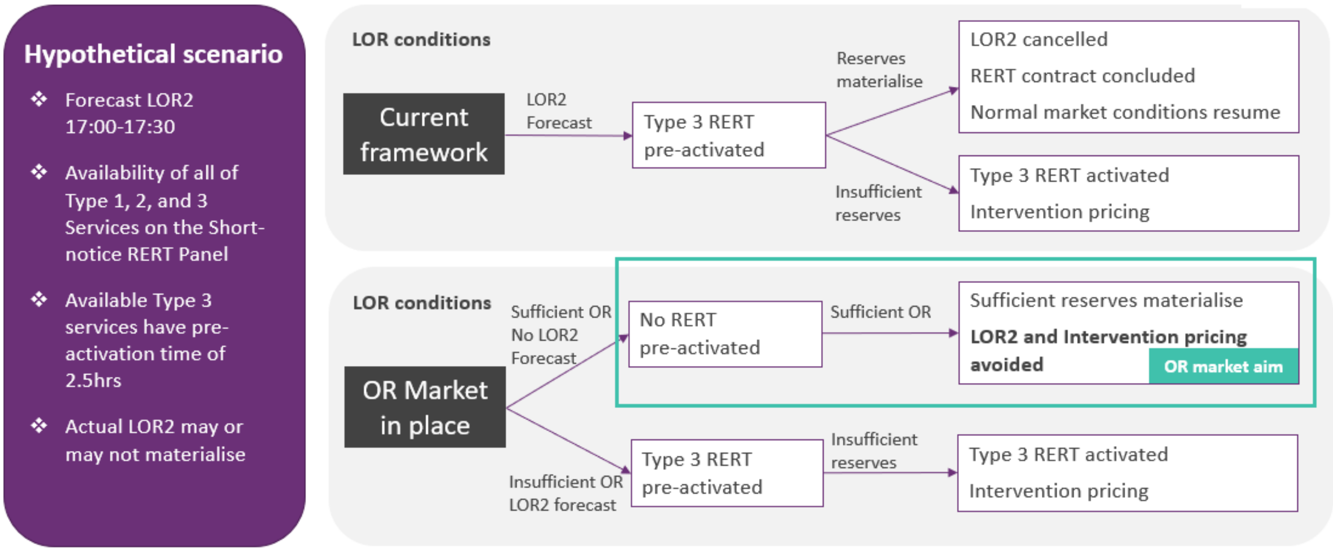


Figure 17 Hypothetical scenario outlining how an OR market can help avoid AEMO intervention and RERT costs, whilst retaining the ability to engage RERT if reserves fail to materialise. To note any activated RERT would proportionally reduce the OR requirement.

The scenario highlighted in Figure 17 in green represents the intended value of an Operating Reserves market, avoiding a forecast LOR2 and the need to pre-activate and activate RERT Services (with associated Intervention Pricing) to meet reserve requirements.

The intended benefit of an Operating Reserve market is highlighted by the ability to bring RERT providers into the market, avoiding the separation of reserves from the energy market, avoiding the need to consider double-dipping of provision of RERT and energy, and avoiding intervention pricing. The automation of reserve procurement also significantly reduces complexity for the system operator.

Out-of-market costs are currently incurred whenever RERT is pre-activated or activated. When RERT is activated, intervention pricing applies. AEMO requires the ability to procure and activate RERT if operating reserve fails to materialise but does see a possible reduction in the pre-activation and activation of RERT due to forecast uncertainty. AEMO notes that to be a RERT provider prohibits participation in the energy market. Bringing current RERT providers into the energy market should efficiently support contributions to reliability, particularly if RERT is exercised less often.

This confidence and certainty in the provision of reserves through an Operating Reserve market is the key requirement to allow an Operating Reserve market to replace some RERT services and requires:

- Certainty in the provision of Operating Reserve in future periods as reported in pre-dispatch, with confidence in how this may change as a result of market conditions in the lead up to dispatch.
- Confidence in that enabled Operating Reserve is provisioned and that compliance monitoring sufficiently ensures anticipated participant behaviour.

The technical advice prepared in this report is predicated on a regional Operating Reserve market, noting that under a redeveloped ST PASA – see Section 2.2.2 – the reserve assessment will be made on a more granular nodal basis. Analysis of Operating Reserve market performance, once implemented, would reveal whether a regional Operating Reserve market was appropriate or whether Operating Reserve market design requires enhancement to consider sub-regional reserve requirements. The consideration of constraints requires further exploration during detailed design.

In scenarios where insufficient reserves materialise (Scenarios 2 and 4), if reserves further decline to LOR3 levels then interventions (including load shedding) would proceed as per the current intervention framework.

5.2 Participation

The key eligibility requirements to provide Operating Reserve is the capability to provide offers of energy in pre-dispatch and meet obligations to provide energy when dispatched in an interval. That is, all scheduled and semi-scheduled resources are envisaged to be eligible providers of operating reserve. To note in particular, this includes demand response, VPPs, batteries, and VRE (Figure 18 Operating Reserve may be provided by each of VRE (a), scheduled bidirectional units (b), and scheduled loads (c).Figure 18). Whilst the capability of fast-start units, such as gas turbines, to provide Operating Reserve is clear and readily understandable, several opportunities emerge when considering participation by a broader range of providers.

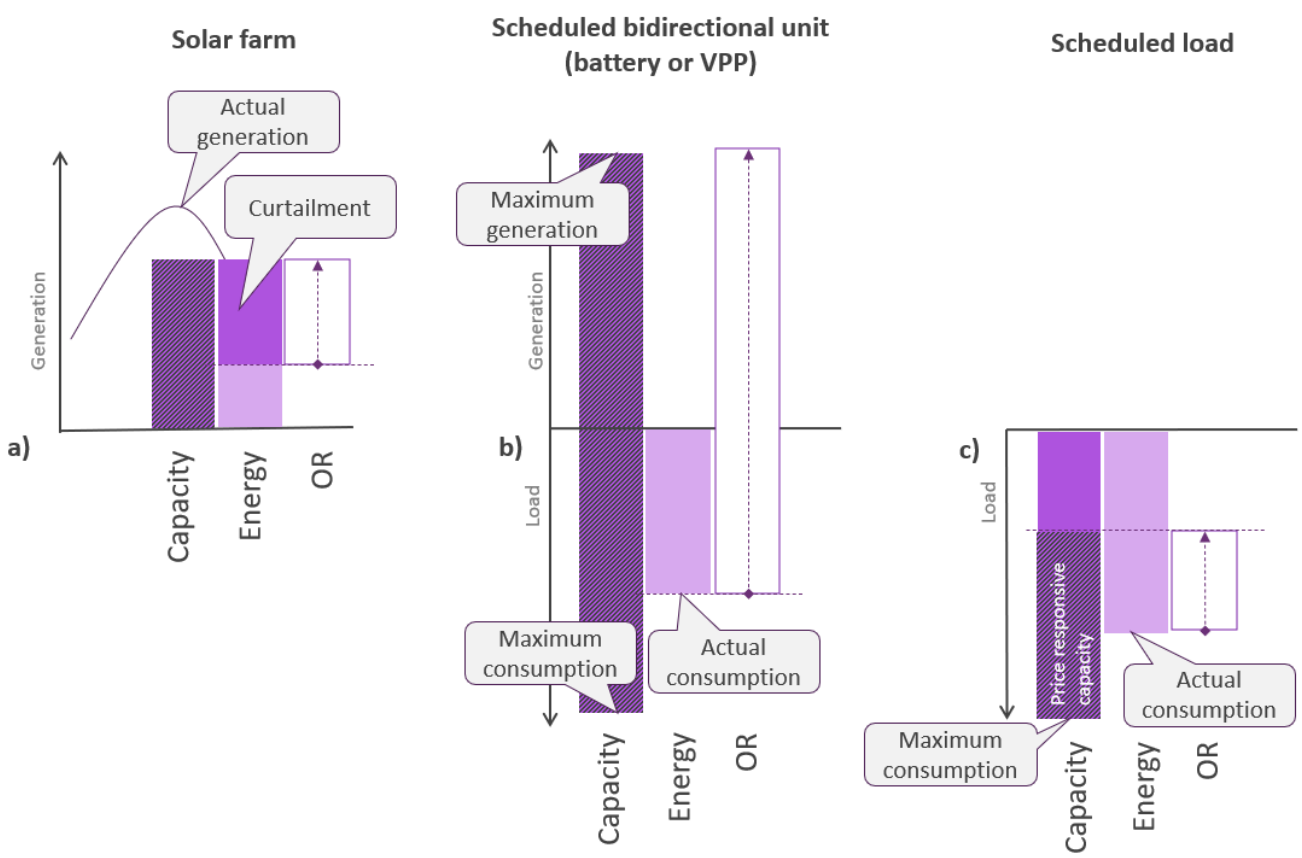


Figure 18 Operating Reserve may be provided by each of VRE (a), scheduled bidirectional units (b), and scheduled loads (c).

Curtailed VRE may be particularly suited to providing operating reserve (Figure 18a) if curtailed for financial reasons at times of negative prices. This may also extend to curtailed distributed solar under aggregated orchestration, though network constraints would need to be carefully considered. Scheduled bidirectional units (such as batteries or VPPs) may provide operating reserve across the full range of dispatch capability from maximum load to maximum generation (Figure 18b), and scheduled loads that have price-responsive capacity may provide operating reserve through this capacity up until their inflexible consumption requirements (Figure 18c). This may particularly suit aggregated coordination of price-responsive demand response resources. Participation from scheduled loads may require concurrent registration of 'price-responsive capacity' and 'non-price-responsive capacity' as per the requirements for the Wholesale Demand Response mechanism and design of the proposed Scheduled Lite reform initiative. To note, an Operating Reserve market may provide an explicit incentivisation pathway for VPPs and a broader set of large users to participate as scheduled resources to be eligible to provide OR.

5.3 Scheduling

A range of potential procurement options exist for an Operating Reserve market. Leveraging international examples, AEMO has explored models based on a (price, quantity) pair structure and models based on quantity offers only, where price is set through the determination of an opportunity cost for marginal reserves.

Procurement options must provide for the following participation:

- A Facility offering energy into the market in the current dispatch interval
- A Facility not currently offering energy into the market but with <30 minute start-up-time (i.e., a Fast Start Facility)
- Storage to ensure sufficient State of Charge is maintained to meet future energy needs
- Demand Response, to ensure capability to curtail is available within 30 minutes

5.3.1 Price Quantity Pairs

An offer structure based on price quantity pairs could be structured similarly to current FCAS Contingency services, with similar bidding rules that apply to the energy market:

- Offers can consist of up to 10 bands with non-zero MW availabilities;
- Band prices must be monotonically increasing;
- Band prices must be set by 12:30 on the day prior to the trading day for which the offer/bid applies;
- Band availabilities, enablement limits and break points can be rebid under rules similar to those applying to the energy market.

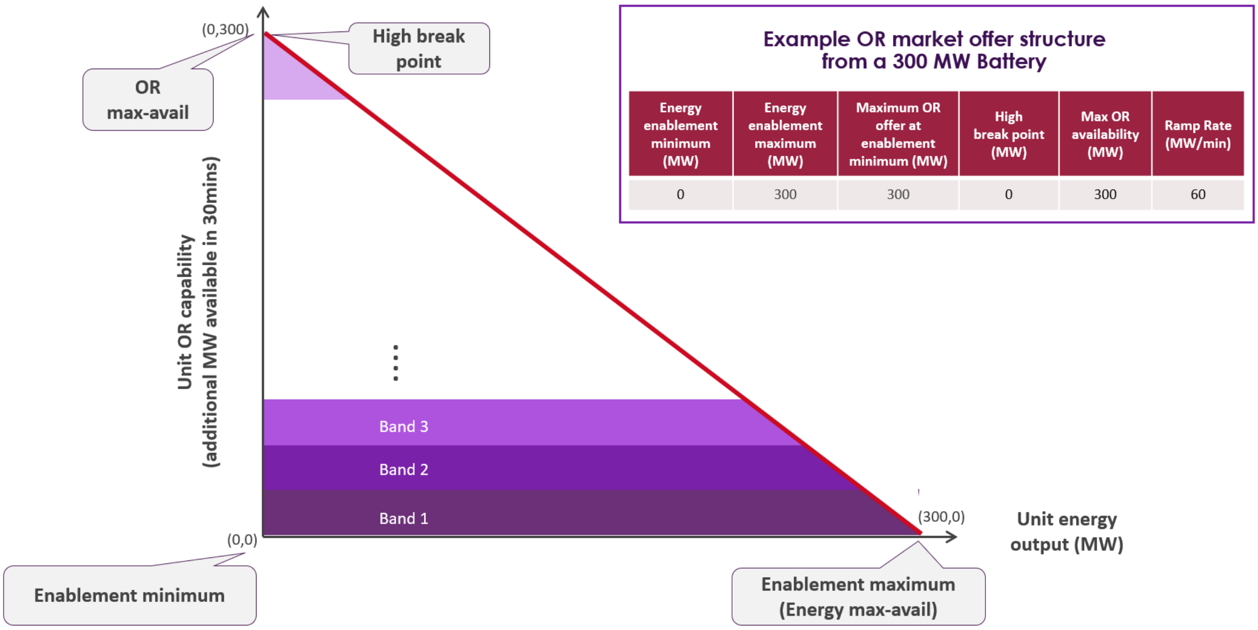
Participants will bid under their single parent DUID, using 10 bid bands with ($, MW) pairs. The Operating Reserves MW offer corresponds to additional capacity (above what is currently being dispatched) to be available in the dispatch interval 30-minutes ahead, though there is possibility for this to be instead the total MW availability, with NEMDE subtracting the currently dispatched capacity to calculate the amount of Operating Reserve offer to clear.

An example Operating Reserve offer structure and trapezium is shown in Figure 19 for a hypothetical 300 MW battery, with a minimum generation of 0MW, and ramp-rate of 60 MW capable of ramping >300MW within 30 minutes. An additional example is provided in Figure 20, for a generator with a lower ramp rate which acts to cap the maximum reserves that may be offered over 30-minutes.

There are several key coordinates of the OR-Energy capability trapezium with parallels to the FCAS-Energy trapezium. These are:

- **Maximum Availability**: The maximum OR that the Facility can provide as energy in T+30 mins.

- **Energy enablement minimum**: The minimum amount of currently dispatched energy required for an OR market offer, in this example 0 MW. (Note that a generator able to offer OR (availability 30 minutes ahead) from a cold-start, offers would be made for OR only).
- **Energy enablement maximum**: The maximum amount of currently dispatched energy for an OR market offer. This would typically be the max-avail of the generator (300MW in this example).
- **Low break point**: This is the lowest dispatch for energy at which the facility can offer its maximum OR quantity, in this example 0 MW.
- **High break point**: This is point at which maximum OR availability can be offered. That is, if the generator is currently being dispatched for 50MW, it is able to offer the full max-avail of 300MW as Operating Reserve for the DI 30minutes ahead. If the unit is dispatched for energy above this amount, the total amount of Maximum OR availability must decrease (since OR is defined as the *additional* amount of energy able to be offered in the DI 30 minutes ahead). That is, from this point, the trapezium must decrease linearly to zero OR offers for the DI 30 minutes ahead when the generator is being dispatched in the current DI for energy at max-avail.



Energy enablement minimum (MW)	Energy enablement maximum (MW)	Maximum OR offer at enablement minimum (MW)	High break point (MW)	Max OR availability (MW)	Ramp Rate (MW/min)
0	300	300	0	300	60

Figure 19 Example OR Market offer structure for a 300MW battery with a 60MW/min ramp rate.

A validation would be created to ensure that there is convex bidding, that is, the bid band prices monotonically increase from current dispatch level to maximum possible generation. The individual offers for DUIDs will be an input to NEMDE, and the output will be individual bids dispatch for DUIDs. NEMDE will enable MW of Operating Reserve offers in merit order of cost. The highest cost offer to be enabled will set the marginal price for Operating Reserve.

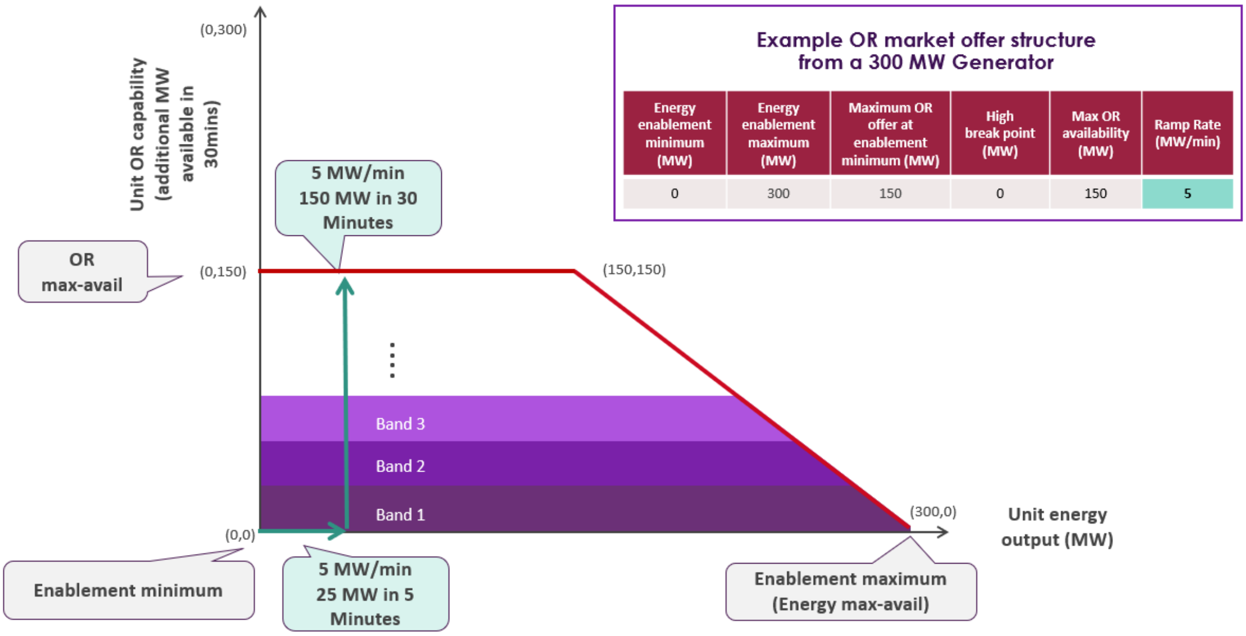


Figure 20. Example OR Market offer structure for a 300MW generator with a 5 MW/Min ramp rate.

To note, these are example offers intended to illustrate the salient points of the OR-Energy trapezium. Detailed features would be developed in consultation with stakeholders, and in particular with demand-side resources.

5.3.2 Quantity offers

An alternative approach to price quantity pairs would be to allow offers to be made for quantity only, where the price of those reserves is derived from energy offers.

Examples of how energy offers may be used to set the price of reserves are provided in Table 3 and Table 4. Table 3 includes three resources, all 20 MW nameplate capacity, with increasing energy prices and decreasing Ramp capability. In this example the demand is 15 MW and with zero ramp requirement the energy price would be $5.

Table 3. Resource bids, capacity and ramp rates.

Resource	Energy Bid ($/MWh)	Capacity (MW)	Ramp Rate (MW/hr)
G1	$5	20	20
G2	$20	20	10
G3	$40	20	5

Table 4 shows the opportunity costs for varying levels of identified ramping needs. In the event that between 0-20 MW/hr is required, that quantity of reserves may be delivered without impacting energy dispatch:

0 < RR < 20 MW/hr, Reserves can be provided by G3/G2 offline (15 MW/h) and 5 MW/hr from G1 while being dispatched for 15 MW.

20 < RR <30 MW/hr, Requires G1 supply additional reserves (5-20 MW/h) which reduces dispatch for energy to between 5-15 MW for energy to retain headroom (5-15 MW/hr) making G2 the marginal unit.

30 < RR <35 MW/hr, Requires G2 to be reduced alongside G1, to between 0-5 MW (up to 5 MW/hr), making G3 the marginal unit.

Table 4. Pricing outcomes according to ramping requirements.

Ramp requirement (MW/hr)	Op. cost ($/MW/hr)	Rationale
0 < RR < 20	$0	Any resource can provide ramping with no change in dispatch
20 < RR < 30	$15	Must back off energy from G1 and increase G2. Energy price becomes $20/MWh.
30 < RR < 35 MW	$35	Must back off energy from G1 and increase G3. Energy price becomes $40/MWh.

The advantages of using opportunity cost to set the price of Operating Reserves is that there is no requirement to receive pricing from participants, thereby reducing the ability of participants to exert market power.

However, such an approach has two limitations which may not reflect the needs of an Operating Reserve market in the NEM, including bespoke arrangements that may be needed for offline units to set the price of reserves, and it may not allow higher pricing than the MPC, potentially limiting incentive to provide OR.

5.4 Co-optimisation and interaction with NEMDE

NEMDE currently co-optimises energy and FCAS. That is, NEMDE may move the energy target of a scheduled or semi-scheduled generating unit, wholesale demand response unit, or scheduled load in order to minimise the total cost (of energy plus FCAS) to the market. This process is inherent in the dispatch algorithm and may be extended to include co-optimisation of Operating Reserve.

It may be possible for NEMDE to minimise the total cost to the market of energy plus FCAS plus Operating Reserve. Even though the Operating Reserve is not required to be available in the current dispatch interval, the cost to the market for providing it *is* incurred in the current dispatch interval, hence allowing efficient co-optimisation. What is dispatched as *energy* in the dispatch interval 30-minutes ahead is then a co-optimisation of offers in that interval for energy, FCAS and Operating Reserve (for the 30-minutes ahead again). Offers would be co-optimised as per the objective function, in accordance with the Energy-OR capability trapezium.

We provide an example timeline showing offers and amounts dispatched of energy, FCAS and Operating Reserve and amounts dispatched for an example hour during which an Operating Reserve market is active (Figure 21). FCAS offers needn't be constrained in the current dispatch interval by OR offers. That is, the FCAS-Energy trapezium is based on dispatch in the current interval, and hence FCAS offers should remain unaffected by the OR market. This is represented in Figure 21.

At 16:00 in the example below, the amount of energy currently dispatched in the current DI *plus* the amount of Operating Reserve dispatched in the current DI must equal the energy *offered* at 16:30. Similarly at 16:30 for the dispatch interval at 17:00. The effect of the Operating Reserve market is to increase the amount of energy offered in subsequent intervals for which reserves are low.

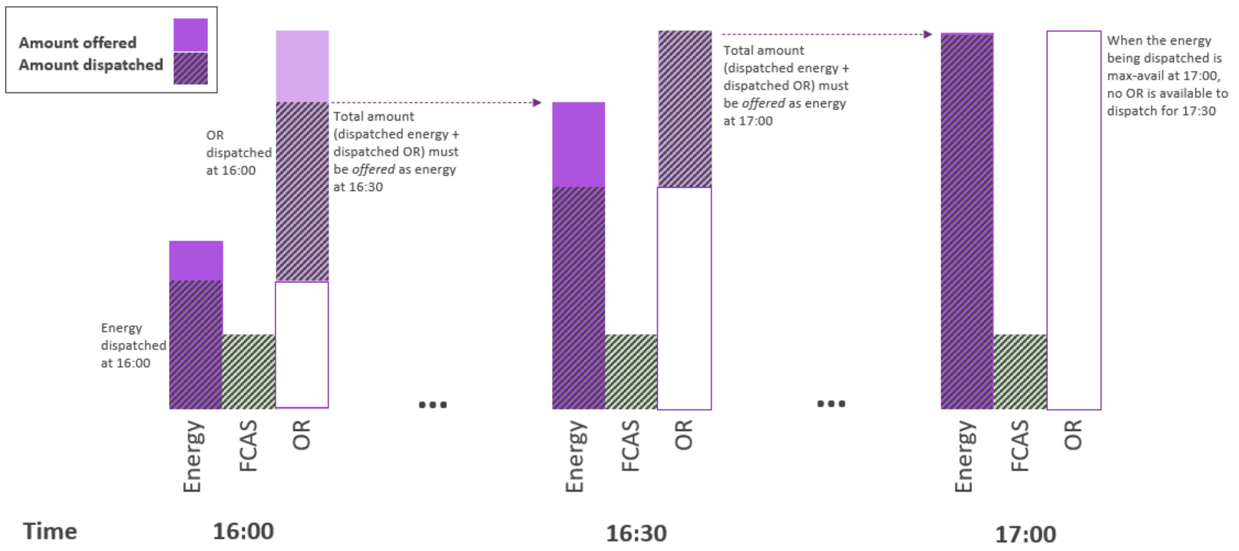


Figure 21 Schematic overview of how energy, FCAS and OR offers may interact in dispatch. The total of energy dispatched in the current interval *plus* the OR dispatched in the current interval must equal the energy *offered* in the interval 30-minutes ahead. Half-hourly intervals are shown above to illustrate the intent of the operating reserve product, though all markets would be dispatched on a rolling 5-minute basis.

5.5 Obligations

Key market design considerations include the obligations surrounding offers, monitoring arrangements of participant performance, and the formulation of penalties in the event of non-compliance.

AEMO recognises that the Australian Energy Regulator is the appropriate organisation to consider compliance issues in detail but provide initial thoughts on the obligation here.

The working model provided by AEMC identifies the obligation for a participant dispatched to provide operating reserve as:

> *The participant's bids in the energy market for each dispatch interval over the next 30-minutes must be consistent with providing that level of reserve as energy in 30-minutes' time. In subsequent intervals the reserve provider may change the volumes it is willing to bid to provide energy at different prices, but is not able to lower its maximum available capacity for the interval that corresponds with its reserves commitment (the interval 30 minutes after dispatch as reserves). In order to comply, a unit with a start-up profile longer than five minutes would need to be online and at minimum generation by the necessary time.*

AEMO has explored options for compliance with dispatch for Operating Reserve and identified two approaches which may be considered against settlement outcomes to ensure appropriate balance between risks on participants and AEMO. The nature of reserves being dispatched ahead of a dispatch interval creates risks that changing system conditions between dispatch and delivery impact the ability or need for reserves to be delivered, similarly the obligations on participants should not limit participation in other markets where of greater value to the system.

The two explored options include an offer obligation and a ramp obligation:

- The "offer obligation" would require the Operating Reserve quantity (energy + dispatched operating reserves at T0) to be offered in the relevant dispatch interval (T+30) and any prior intervals for ramp limited Facilities (those unable to ramp for the full Operating Reserve quantity in a single dispatch interval), this option is outlined in section 5.5.1.
- The "ramp obligation" would also require energy offers in the relevant dispatch interval (T+30) but compliance would be assessed based on the ramp constrained capability for the facility in the relevant dispatch interval. This approach would require any ramp-rate limited facilities to be dispatched to a sufficient energy level in the intervals prior to the operating reserve interval (T+30) to have capable reserves corresponding with the dispatched operating reserve quantity, this option is outlined in section 5.5.2.

For facilities which are not ramp limited, being those facilities capable of ramping for the full quantity of dispatched reserves in a single dispatch interval, the explored options are essentially equivalent. Figure 22 shows the inter-interval obligations created through dispatch for Operating Reserve for a ramp unconstrained facility (right) and a ramp unconstrained facility (left), in this example the unconstrained facility dispatched for Operating Reserve in T+30 interval and T+35 interval may be delivered regardless of the start of interval operating level whilst the facility with a constrained ramp would need to be dispatched for a minimum quantity across T+15 to T+25 to ensure sufficient usable headroom was available in T+30 and T+35.

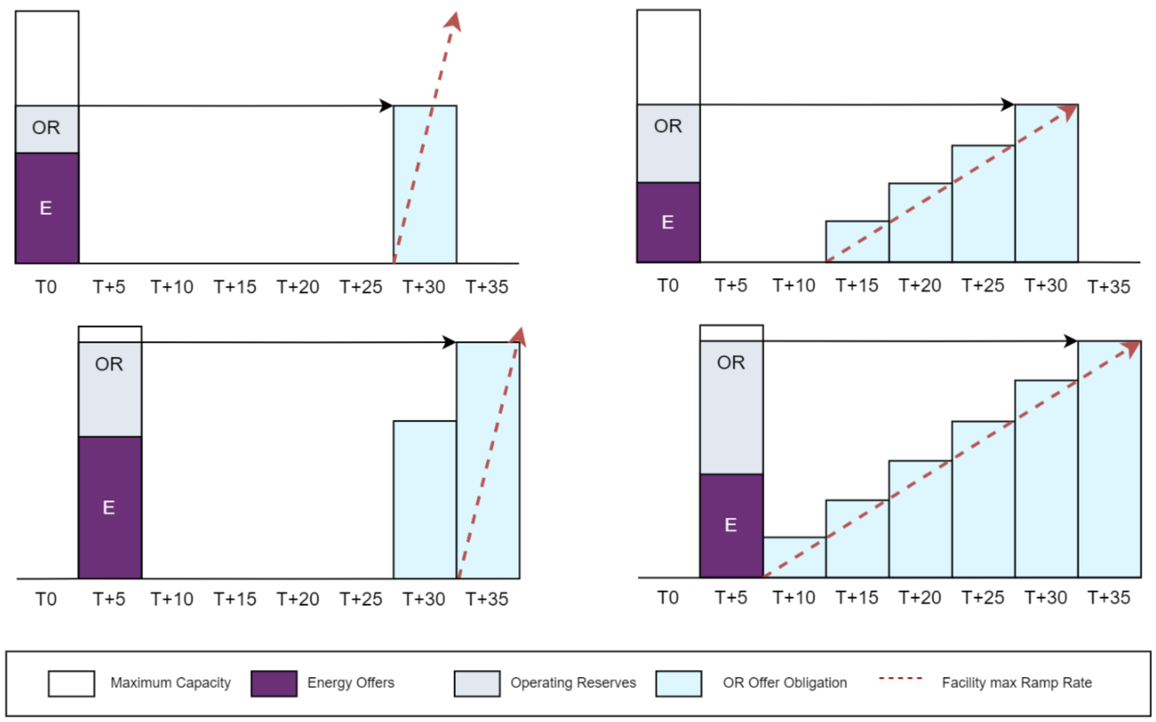


Figure 22. Participation in Operating Reserves across two Operating Reserve intervals for a fast ramp facility (left), slow ramping facility (right).

5.5.1 Offer Obligations

An offer obligation for Operating Reserves would require facilities dispatched for Operating Reserve to offer a quantity of energy into the relevant dispatch interval corresponding to the sum of dispatched Operating Reserve and energy at the time of Operating Reserve dispatch. Figure 22 shows this interaction for two consecutive dispatch intervals for a facility across energy and Operating Reserve. Where a facility is unable to ramp for the full quantity of cleared reserves in a single dispatch interval, this option would require the market participant to submit offers in the energy market in the intervals leading up to the Operating Reserve interval such that it could be dispatched to its scheduled Operating Reserve. Figure 23 (left) provides an example of these additional offer obligations, where the first Operating Reserve dispatch for T+30 creates obligations in T+15 to T+35 corresponding to the facility's maximum ramp rate, these obligations are then increased due to the second Operating Reserve interval dispatch, highlighted in red. In this example, whilst the Facility was unable to deliver the full quantity of reserves, it would have met its offer obligations.

5.5.2 Ramp Obligation

An alternative option explored would be to measure the delivery of reserves as the offered ramp constrained capability of a facility in the relevant Operating Reserve interval. Requiring ramp constrained capability to meet Operating Reserve dispatch may mean that ramp constrained resources incur a cost generating to a level that allows them to ramp to their scheduled operating reserve quantity. Figure 23 (right) shows an example of these obligations across two Operating Reserve intervals, for which the Facility would be deemed non-compliant for the second Operating Reserve interval due to its ramp capability in that interval.

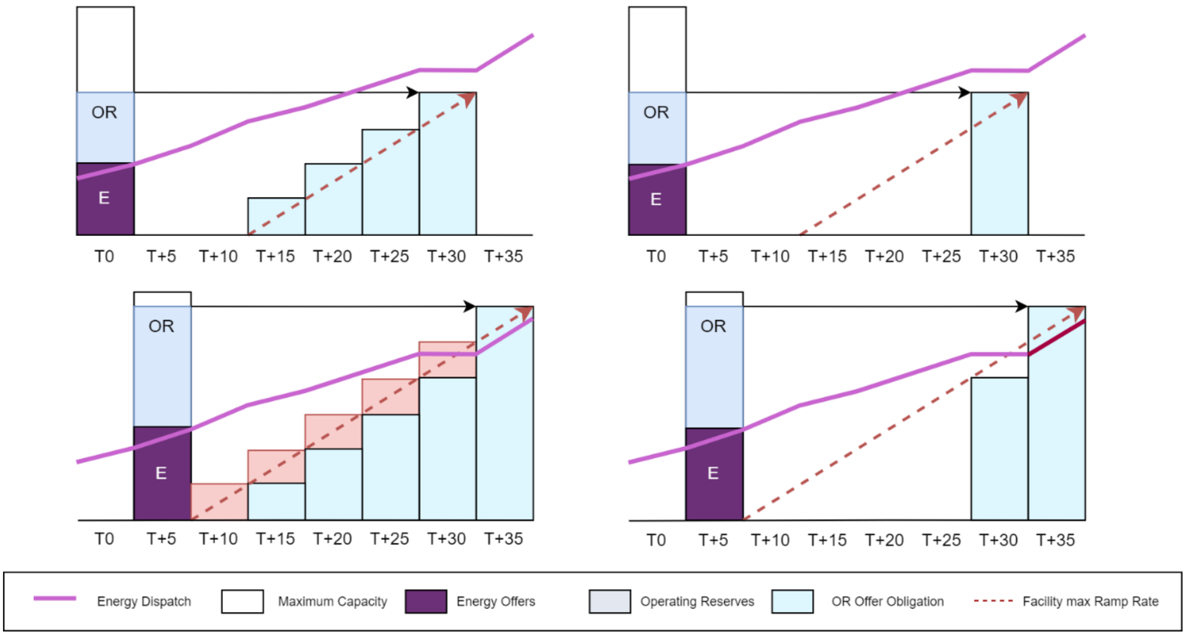


Figure 23. Participation in Operating Reserves across two Operating Reserve intervals under an offer obligation (left) and ramp obligation (right).

5.5.3 Recommended Option

Of the explored options, the offer obligations discussed in section 5.5.1 present the lowest risk to participants, requiring energy offers in the relevant dispatch interval without the need to be dispatched. This also supports efficiency gains by energy being dispatched by the Facility only if is required. However, the potential that procured reserves are not able to be delivered under this model presents a risk to the efficacy of the Operating Reserve framework and operator confidence that reserves will be available. AEMO considers that placing a ramp obligation on participating units for OR, as discussed in section 5.5.2, presents the lowest risk to system operation, however the settlement and compliance outcomes should reflect the increased risk on participating facilities.

5.5.4 Future design investigations

AEMO has welcomed the opportunity in this section to progress high-level design of an Operating Reserve market interactions with dispatch processes, but notes that detailed design will require careful consideration. In particular, issues regarding interaction and solving through pre-dispatch, interaction with intervention frameworks, interconnector participation, and the options for obligation, co-optimisation, procurement and compliance outlined above.

5.6 Compliance

AEMO recognises that the Australian Energy Regulator is the appropriate organisation to consider compliance issues in detail but discusses initial thoughts here on several options regarding the formulation of penalties (or settlement options) in the event of non-compliance. The working model indicates the starting point for considerations:

> *If the capacity enabled in one dispatch interval to provide reserves is not physically capable of being dispatched as energy in the interval 30 minutes later, it would be non-compliant with its reserves obligation. As a starting point, the penalties should mirror those for non-compliance with FCAS obligations. This includes:*
>
> - *repayment of revenue received in the Operating Reserve market, and*
> - *a maximum financial penalty of $100,000.*
>
> *Further consideration may be needed to determine whether there should be any exemptions from compliance, such as cases where non-compliance occurs due to matters outside of the control of the participant. This may place a burden and cost on participants and the AER when enforcing compliance, due to the many shades of grey involved in determining what is in and out of the control of a party (such as a safety or security issue that could have been avoided through better maintenance practices). The Commission and the AER will also need to consider whether the penalty should be a civil penalty or a financial penalty only.*

The proposed model by the AEMC aligns with AEMO's option for a "ramp obligation" as discussed in section 5.5.2, this model of compliance would provide greatest certainty to AEMO as the system operator that offered and cleared reserves would be available in the relevant dispatch interval. However, depending on the compliance outcomes for non-delivery (particularly for ramp constrained resources) this option may present a prohibitive risk for participation. As such, it is important to consider the design options for obligations and compliance together as a working model.

The two options for service delivery have been considered, the penalties included in the AEMC's working model and an alternative "pay for performance" model.

Table 5. Settlement Outcomes for Operating Reserve delivery options.

Option	Obligation	Option A	Option B
		Pay for Performance	**Penalties**
1	Offer Obligation: Must offer OR quantity in relevant interval (and any prior intervals for a slower ramping Facility) as available capacity in the energy market	Facility is paid for MW of availability (**ignoring ramping capability**) offered in relevant OR intervals up to the enabled OR quantity, any shortfall in offers is withheld.	Facility is paid for MW of availability (**ignoring ramping capability**) offered in relevant OR intervals up to enabled OR quantity, any shortfall in offers is paid to AEMO according to a refund factor (which could be static, or dynamic and greater than a value of 1 according to reserves).
2	Ramp Obligation: Must be capable of delivering OR quantity in relevant interval	Facility is paid for MW available for dispatch (**taking into account ramping capability**) in relevant OR interval up to enabled OR quantity. Any shortfall is withheld.	Facility is paid for MW available for dispatch (**taking into account ramping capability)** in relevant OR interval up to enabled OR quantity. Any shortfall is paid to AEMO according to a refund factor (which could be static, or dynamic and greater than a value of 1 according to reserves).

Pay for performance would limit the penalty for non-compliance *only* to repayment of revenue received in the Operating Reserve market. In this model, a participant that offered and was dispatched for operating reserves would either:

1. offer this additional reserve capacity as dispatched, and subsequently receive payment for this reserve plus the payment for energy dispatched in that interval; or
2. not offer the additional reserve capacity as dispatched, and not receive the payment for reserve (though still receiving payment for any energy dispatched in that interval).

Table 5 includes a comparison of the considered options, AEMO considers that pay for performance may support those cases where non-compliance clearly occurs due to matters outside of the control of the participant and hence reduce the burden and costs on participants and the AER when enforcing compliance. The consequence, however, is that there would be reduced confidence in the provision of reserves which may require the adjustment of the amounts of reserve procured to adequately cover power system risk.

The strength of compliance enforcement and rules regarding commercial rebidding will ultimately determine operator confidence that i) OR offered in pre-dispatch will remain available, and ii) that cleared OR will be physically available in the ahead time-frame. That is, the strength of compliance and confidence of provision is fundamentally important for any market to be able to avoid operator intervention.

AEMO's preference is for "penalty for non-delivery" with robust compliance frameworks in place. AEMO's further preference is that market design remains consistent with existing compliance arrangements where possible, with contingency FCAS compliance providing a starting point for development, noting any possible arrangements require further consideration and consultation with stakeholders and the Australian Energy Regulator.

We can summarise the advantages and disadvantages of each in the table below.

Obligation/settlement option	Advantages	Disadvantages
1. Penalty for non-delivery (cleared OR must be offered as energy in the dispatch interval 30min ahead, penalty for non-delivery)	Provides greatest certainty to the system operator that availability will materialise. Supports confidence for the operator to avoid declaration of LOR conditions.	Difficult to assess non-compliance in the event of circumstances (e.g., constraints) beyond a participant's control. Participants carry the risks of uncertain energy market dynamics in the subsequent 30 minutes. System operator may need to consider ramping or dispatch interactions in the intervening time-interval between offer and energy dispatch.
2. Payment only for performance (no penalties) (cleared OR paid only if offered in the dispatch interval 30min ahead, no payment (nor penalty) if offer fails to materialise)	Provides some simplicity of compliance. Allows participants to manage their own risks if ramping considerations or dispatch patterns in the intervening time-interval make the OR offer uncommercial to materialise.	Offers little confidence to the operator that reserves will materialise. Counteracts the ability for a market to support reduced intervention. System operator carries the risk of uncertain energy market dynamics in the intervening 30 minutes. Additional OR may need to be procured to a level that supports confidence to avoid declaration of LOR conditions.

The most aligned approach with existing FCAS market obligations is to take an entirely ex-post compliance approach to OR, where payment for reserves is made at the time of dispatch and any failure to meet expected service delivery is managed through ex-post assessment of participant behaviour. It is important to note however, that FCAS compliance is often highly manual, typically targeting FCAS providers that have persistently failed. Operating Reserve delivery requires participants actively participate in the energy market in a manner which supports the system. These interactions are measurable and may therefore allow for preferred automated approaches to verification of service delivery and interlinkages with settlement outcomes and compliance assessments.

A final compliance measure to note is that, in any interval, a participant cannot offer a certain range of its output (e.g., 50-100% of its maximum capacity) as OR without also offering it as energy. This removes the possibility that a participant with a preference for earning revenue in the OR market (and energy in a later interval) could achieve this by completely removing capacity from the energy market in the current interval. Note that such a participant could, in general, manage its preference by increasing its energy market bid prices, and decreasing its OR market bid prices. This measure removes the possibility that such a preference creates a reliability issue for the system.

5.7 Potential integration with a Capacity Mechanism

There is close interaction between an Operating Reserve market and a Capacity Mechanism, considered during the design of the ESB NEM P2025 reform program[26]. Both aim to ensure customer reliability as the energy system transitions towards very high penetration of renewables, and both pay for capacity in ahead timeframes.

A capacity mechanism is designed for investment timeframes (in the scale of years), aiming to reduce the risk of a disorderly transition and providing an alternative more predictable revenue source for investors building the capacity that the market needs as fossil capacity exits. An Operating Reserve market is designed for operational timeframes (in the scale of hours), aiming to reduce the risk of operator intervention and providing incentive for participants to provide capacity at times of low reserve and forecast uncertainty.

With the building of significant battery and storage assets, it is possible that in the far future there may be sufficient storage to meet ramping/reserve requirements for a broadly electrified energy sector – but until this point, the value of an operating reserve is to manage variability/uncertainty/ramping requirements. That is, predominantly to solve the online/offline problem and the insufficient provision of headroom, for which there is significant emerging risk not addressed by current reforms or investment.

There is a link between the performance obligations under any possible capacity mechanism and an OR design. The merit order for which capacity payments/obligations are made for availability during LOR conditions may be *precisely* determined by an Operating Reserve market of the type considered in this report. This option deserves further detailed investigation and exploration.

There is relevant analysis from Europe on the possibility of co-existence between a Capacity Mechanism and a market that values reserves during scarcity.

> *The dilemma between capacity markets and scarcity pricing is false: scarcity pricing does not preclude capacity remuneration mechanisms. It is perfectly compatible with capacity remuneration mechanisms. Precedence, however, matters: before we proclaim the 'energy-only' market dead, let us give it an opportunity to function properly.*
>
> *- A. Papavisilou, 2020, Scarcity pricing and the missing European market for real-time reserve capacity. The Electricity Journal (33), 10, 106863 https://doi.org/10.1016/j.tej.2020.106863*

A review of several markets around the world indicates many instances where both markets coexist (Table 6).

Table 6 Selected international energy markets and their incorporation of capacity and Operating Reserve markets.

Market	Type of market	Capacity market?	Operating/short-term/ramping reserves?
ISO-NE	Forward capacity market	✓	✓
PJM	Forward capacity market	✓	✓
NYISO	Prompt capacity market	✓	✓

[26] https://esb-post2025-market-design.aemc.gov.au/reports-and-documents Essential System Services Reform Recommendations, and FTI Consulting report on Essential System Services in the NEM.

CAISO	Day ahead and real-time	✓	✓
SPP	Day ahead and real-time	x	✓
MISO	Voluntary capacity market	✓	✓
ERCOT	Energy only	x	✓
Ontario	Real time and capacity	✓	✓
Mexico	Real time and capacity	✓	✓
UK	Forward capacity market	✓	✓
EirGrid	Capacity options market	✓	x

The Reserve Capacity Mechanism (RCM) operated by AEMO in the Wholesale Electricity Market (WEM) in Western Australia does not currently integrate explicit procurement of capacity capable of meeting ramping needs of the system. However, the current review of the Reserve Capacity Mechanism by the Coordinator of Energy has identified an emergent need for such procurement, with potential options under consideration including a "flexibility capacity" product, dispatched in real-time through a co-optimised ramping market[27].

Various capacity markets have a base auction for capacity with a long forward horizon (for example, 3 or 4 years), but then conduct subsequent Residual Auctions in T-2 years and T-1 year timeframes to account for excess or shortfalls in available capacity according to updated forecasts.

There is potential integration of a Capacity Mechanism with an Operating Reserve market by considering Operating Reserve as a Residual T-30 *minute* auction, similarly accounting for excesses or shortfalls in available capacity according to updated forecasts in operational timeframes. That is, an Operating Reserve market may use the same financial procurement mechanism as a Capacity Market, auctioned 30-minutes ahead, or may use the same obligation framework, with compliance awarded through the provision of availability when an Operating Reserve market is active. This could incentivise investment in capacity that can respond at times of scarcity – precisely the requirement of a capacity mechanism.

A simpler model may be to allow the Capacity Mechanism to procure availability solely in planning timeframes, allowing an Operating Reserve to ensure availability in operational timeframes.

AEMO strongly recommends further detailed investigation of the interactions between a capacity mechanism and an Operating Reserve market for the provision of availability in operational timeframes. Additional investigation of international markets with comparison and parallels would be beneficial to consideration and draft determination.

[27] RCM Review Working Group - Meeting 2 June 2022 – Meeting Papers Slide 29, Page 43.

6 Preliminary advice on cost recovery

An appropriate Causer Pays methodology for Operating Reserve requires collaboration and detailed consultation with stakeholders

AEMO notes any cost-recovery approach must be determined in close consultation with stakeholders, and recommends simple arrangements as an initial design, which may be uplifted through subsequent review of the value of the Operating Reserve market and suitability of more complex arrangements.

Various options are explored. The stepwise construction of the proposed ORDC may allow for the costs associated with each step of the ORDC to be allocated to relevant causer groups, for example the component associated with forecast demand ramp being allocated to consumers, with uncertainty components being allocated across causer groups including the relevant technology types.

Further specificity may be introduced in the future through technology type uncertainty metrics (e.g., wind/solar) to allow a more targeted allocation. AEMO has considered options for per-facility uncertainty factors tied to maximum availability offers over time, however, a detailed analysis of potential outcomes associated with such a causer pays methodology would be needed to ensure the efficacy of this approach.

There are potential linkages of cost-recovery with the Scheduled Lite reform program of the ESB Post-2025, in particular that participation in Scheduled Lite may allow for an opportunity to reduce exposure to Operating Reserve costs. Providing additional visibility of forecast demand and supply through Scheduled Lite can reduce uncertainty and hence the need for operating reserve.

Trade-offs of any detailed cost-recovery mechanism include simplicity and transparency, with several relevant lessons from the application of causer-pays in FCAS.

AEMO does not provide explicit recommendations on cost-recovery mechanisms and underscores the importance of collaboration and detailed stakeholder engagement.

Cost allocation of an Operating Reserve mechanism guided by causer pays principles will provide incentives for participants to minimise their contribution to the need for reserves without directly participating in the Operating Reserve market. Causer pays methodologies are reliant on both identification of causers and a means to quantify their contribution to the need for the service. This section explores practical means of identifying and quantifying sources of uncertainty.

AEMO has considered causer pays approaches which minimise complexity and implementation risk alongside more complex arrangements which may better target costs and incentives to improve forecasting accuracy.

6.1 Operating Reserve Cost Components

The Operating Reserve market procures reserves to meet both expected demand increases and uncertainty of demand and supply. The costs associated with these two components should be considered separately for the purposes of any causer pays methodology and could include runway pricing formulation or other allocation mechanisms where different price-bands of the demand curve are allocated to various causers.

6.1.1 Relation to the ORDC components

The construction of the ORDC should allow for separate quantities to be attributed to relevant causer groups. Figure 24 identified the breakdown of the ORDC into three quantities:

1. Forecast demand increase (at the 50% Probability of exceedance)
2. Uncertainty associated with LOR2 level
3. Uncertainty quantities greater than LOR2 level

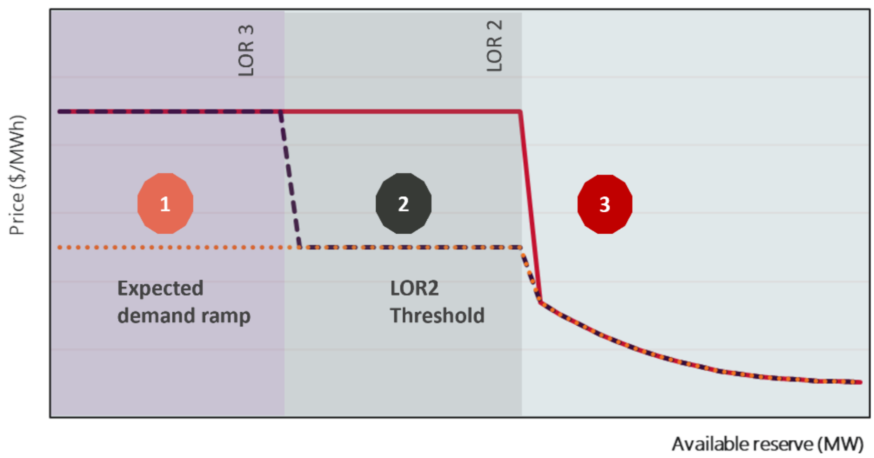


Figure 24. ORDC overview.

Forecast demand increase (1)

The component of Operating Reserve procured to meet mid-point forecast demand increases (50% probability of exceedance) may most logically be paid by energy consumers, the settlement may therefore be applied based on consumption share for each customer as a proportion of the regional quantity procured to meet the expected demand ramp. The quantity associated with the forecast demand increases would be based on the ORDC quantity set in accordance with the methodology described in section 4.4 for each region.

Uncertainty (2 and 3)

The causer pays approach to the cost components of Operating Reserve procured to meet uncertainty up to LOR2 threshold and above, denoted by (2) and (3) in Figure 24, should allocate the quantity of Operating Reserve procured to manage uncertainty to the sources of uncertainty themselves. Where the LOR2 threshold is set by the largest credible contingency or equivalent under redeveloped ST-PASA, the portion may be allocated to generators as current contingency raise FCAS requirements. Beyond the largest credible contingency, the inputs to the uncertainty component of the ORDC may be allocated to resources described in section 4.4, including:

a) Non-Scheduled Loads;
b) Non-Scheduled Generators;
c) Semi-Scheduled Generation
d) Scheduled Generation; and
e) Scheduled Loads.

The construction of the ORDC will identify quantities of uncertainty associated with each of these sources which may then be recovered from each causer group.

6.2 Simple implementation option

A simple approach to causer pays for Operating Reserve would include allocation of costs associated with the component of Operating Reserves procured to meet forecast demand increases to loads (as described above, with the uncertainty component allocated between causer groups).

Allocation according to uncertainty may be simplistically applied through the share of absolute value of generation or consumption for each facility to the full quantity of Operating Reserve procured to mitigate uncertainty. A more targeted allocation could be made by splitting the cost quantities according to the contribution to the ORDC for each causer group and recovering according to the contribution of each facility to that group. Recovery across each causer group may be applied according to the absolute value of generation and consumption for each facility as a proportion of the total generation and consumption for that causer group.

Depending on the granularity of AEMO's uncertainty inputs to the ORDC it may be possible to break down causer groups further to a technology level (e.g., Solar Photovoltaics, Wind) to increase the targeting of costs across smaller causer groups.

This simplistic approach to cost recovery would ensure allocation is made to the appropriate causer groups but not provide an incentive to reduce uncertainty of load and generation.

6.3 Alternative implementation option

An alternative option for causer pays would be to more accurately reflect individual facilities contribution to uncertainty through a contribution factor. Calculation of contribution factors would necessarily require both a forecast and an actual in order to quantify each facilities contribution. This approach is aligned in concept with the causer pays framework used for recovery of Regulation FCAS in the NEM, however, alternative metrics would be required to set the contribution factor for OR.

The factors may apply to the same quantities for each causer group discussed in section 6.2, the contribution of each facility to that group may be quantified according to contribution factors for Operating Reserve based on:

a) Scheduled Generation and Scheduled Loads; maximum availability at the time Operating Reserve is procured against maximum availability in the Operating Reserve interval; and
b) Semi-Scheduled Generation: Unconstrained Intermittent Generation Forecast (UIGF) at the time Operating Reserve is procured against UIGF in the Operating Reserve interval.

Given the absence of forecasts from non-scheduled loads and generation, the allocation of costs to these causer groups may need to applied using a consumption share approach described in section 6.2.

The causer factors applied to Scheduled and Semi-Scheduled facilities may be calculated on a per-interval basis or applied according to a heuristic assessment of previous performance (over a suitable timeframe). A historical approach would likely reduce volatility in contribution factors but reduce the per-interval incentives to improve forecasting.

6.4 Distributed solar and non-scheduled generation

There are potential linkages of cost-recovery from distributed and non-scheduled resources with the Scheduled Lite reform program of the ESB Post-2025, in particular that participation in Scheduled Lite may allow for an opportunity to reduce exposure to Operating Reserve costs. Providing additional visibility of forecast demand and supply through Scheduled Lite can reduce uncertainty and hence the need for operating reserve.

As the market evolves to higher proportions of renewable and distributed energy, any mechanism would need to adapt to continue to provide allocative and productive efficiency. Again, AEMO suggests any possible mechanism be developed after detailed consultation with stakeholders.

7 Implementation costs and timing

AEMO has estimated implementation costs and timing for an Operating Reserve market as part of the NEM2025 Roadmap and Gate 1 Business Case Assessment.

7.1 NEM 2025 Program

The ESB was tasked by the former Council of Australian Governments (COAG) Energy Council to deliver a market design for the NEM to meet the needs of the energy transition beyond 2025. In October 2021, Ministers endorsed the ESB's reform recommendations including a request for AEMO to work closely with industry to develop an integrated regulatory and IT roadmap (Roadmap) to deliver the IT system and business processes together.

AEMO has commenced work to scope the program that needs to be delivered to meet the obligations under the reforms. As part of the initial planning phase, AEMO worked with industry and stakeholder representatives comprising the Reform Delivery Committee[28] (RDC) to identify the suite of initiatives aligned with the ESB's four reform pathways to be included in AEMO's NEM2025 Program.

The timing and costs associated with an Operating Reserve market have been estimated as part of NEM2025 Roadmap and Gate 1 business case assessment[29]. The NEM2025 Roadmap establishes a basis upon which to navigate the breadth of ESB reforms over the coming few years, de-risking delivery and informing implementation timing. AEMO is preparing a Gate 1 business case that sets out two delivery options for the NEM2025 Program and recommends a preferred option based on cost estimates and a qualitative benefits assessment.

7.2 Implementation costs

The implementation cost for each initiative was estimated based on its complexity (being one of very small, small, medium, large or very large). Using a combination of the types of resources, the estimated number of resources and the estimated number of days effort, a total effort estimate was calculated for each complexity rating. The

[28] https://www.aemo.com.au/consultations/industry-forums-and-working-groups/list-of-industry-forums-and-working-groups/reform-delivery-committee

[29] AEMO | NEM Reform Implementation Roadmap

allocation and pricing of this total effort was prepared based on industry benchmarks and tested against 5MS and the Wholesale Demand Response implementation projects. Operating Reserves was assessed as a 'large' project with upfront costs estimated to be approximately $11.4m +/-40% and ongoing costs are estimated to be $7.8m (over a 10 year period). This estimate is based on the assumption that the scheduling of Operating Reserves would be performed by NEMDE, forecasting and ST PASA redevelopment projects are able to provide necessary inputs to the determination of the ORDC and that the replacement of the causer pays system can be leveraged for the settlement of the service. AEMO notes final costs will be dependent on final arrangements that are put in place for bidding, co-optimisation, cost-recovery, and compliance.

7.3 Implementation timing

The Roadmap sets out – for each individual initiative – an assessment of the critical steps and estimated timeframes required to complete them across a standard implementation process. Estimated timeframes for each step within the delivery process have been assessed based on the overall level of complexity associated with implementation of individual initiatives. The Roadmap considers key technology solutions and functional relationships to group, prioritise and sequence the implementation of initiatives.

The timing of Operating Reserves within the Roadmap assumes the AEMC makes a Draft Determination in June 2023 and a Final Determination in December 2023. The timing of the assumed regulatory approvals would not allow Operating Reserves to be bundled with other ESS initiatives like Primary Frequency Response and Operation Security Mechanism (for which a determination is expected to be released in September by the AEMC). The Roadmap outlines an implementation date for Operating Reserves of March 2027, following the release of uplifts to core market systems including Dispatch and Constraints.

The implementation is estimated to be 3.25 years, including the following (overlapping) implementation phases:

- Initiation: 4 months
- Detailed design and prototype 9 to 12 months
- Build and test: 15 to 24 months (MASS, Procedures also during this phase)
- Market Trial: 3 to 6 months

This timing is based on the assumption that the scheduling of Operating Reserves would be performed by NEMDE, forecasting and ST PASA redevelopment projects are able to provide necessary inputs to the determination of the ORDC and that the replacement of the causer pays system can be leveraged for the settlement of the service. As for costs, AEMO notes final timing will be dependent on final arrangements that are put in place for bidding, co-optimisation, cost-recovery, and compliance.

7.4 Assumptions

Informing AEMO estimates of cost and timing for the implementation of an Operating Reserve market are several assumptions, outlined below.

Changes to market systems:

- Bidding system change (leverages bidding system uplift in 5MS).
- Demand curve formulation and integration into dispatch.

- Dispatch – new engine / module.
- Settlement change, no new registration categories.
- Integration with control room tools.

Business changes:

- Detailed design and prototype
- Demand curve formulation
- MASS, Procedures and business process
- Requirements specification and testing

Design assumptions:

- The final design/policy in the rule determination is technically implementable, including compliance regime.
- The FUM or ST PASA uncertainty margin calculation can be leveraged to produce an operating reserve demand curve.
- Operating reserve offers are subject to network constraints as expected in the future DI.
- Operating Reserve market will be accessible to existing and new-entrant generators, scheduled loads and wholesale demand response providers.

Project assumptions:

- Builds on related system development:
  - Forecasting platform upgrade.
  - Causer pays replacement.
- External formulation and certification of operating reserve solve, internal build and test
- Rules-governed procedure consultation (under clause 8.9) will be progressed for all procedures as a single package.
- Project delivery combines waterfall and agile methodologies, and subsequently there is a need for significant project overhead/governance
- The Operations Technology Roadmap has identified the need for a tool to monitor ramping requirements for control room staff. Potential synergies in the delivery of the ramping tool and an Operating Reserve market have not been considered to date.

7.5 Deliverables

An implementation project for Operating Reserves is expected to include the deliverables outlined in the table below.

No	Name	Description
1	Operating Reserve algorithm	A process for determining targets for resources to be available to deliver Operating Reserves. Targets are to be co-optimised with existing energy and FCAS, either through incorporation in NEMDE as

		an additional ancillary service or through a separate solver integrated with NEMDE.
2	Operating Reserve prototype	Proof of concept for deliverable (1)
3	Solution architecture	Documentation of high-level technical solution and how it fits into the market system environment.
4	Business requirements	Documentation of the process and system requirements for an Operating Reserve market.
5	IT modules and supporting infrastructure, upgraded for and integrated with OR algorithm, tested internally and tested with participants	Examples include settlements modules, control room displays, cyber-security systems, hardware, cloud infrastructure, architecture data management and data-interchange.
		System changes
		Integration with OSM solver
		E2E testing
		Industry trial
6	MASS updates	Integration of operating reserve service into the market ancillary services specification document. Involves industry consultation as per rules procedures (NER 8.9).
7	Other rules-governed document amendments	Progressed as a package with MASS updates. Examples include power system operating procedures, market timetable, reserve level declaration guidelines and RERT procedures.
8	Other documentation	Documents not requiring rules consultation. For example, internal and external guides and training materials and IT release documentation.

A1. Price analysis during times of low reserves

Prices during intervals of low reserves 2013-2021

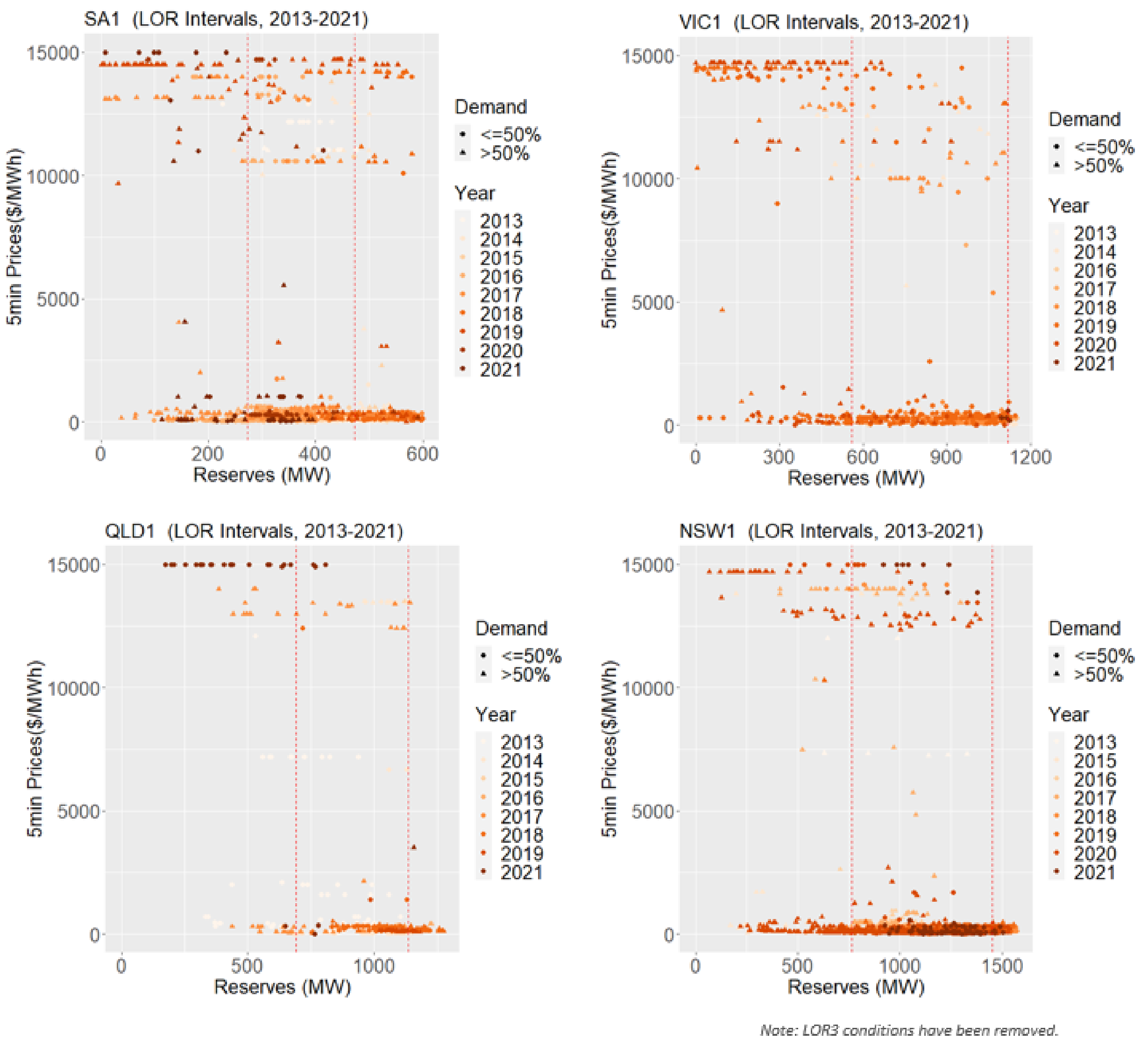


Figure 25 Price vs Reserve data for regions during low reserve 2013-2021 showing an increase in LORs, occurring deeper, and occurring with greater frequency at moderate (<50th percentile) demand. Note that intervention pricing may have been in place for selected intervals.

Prices during intervals of low reserves since 5-minute settlement

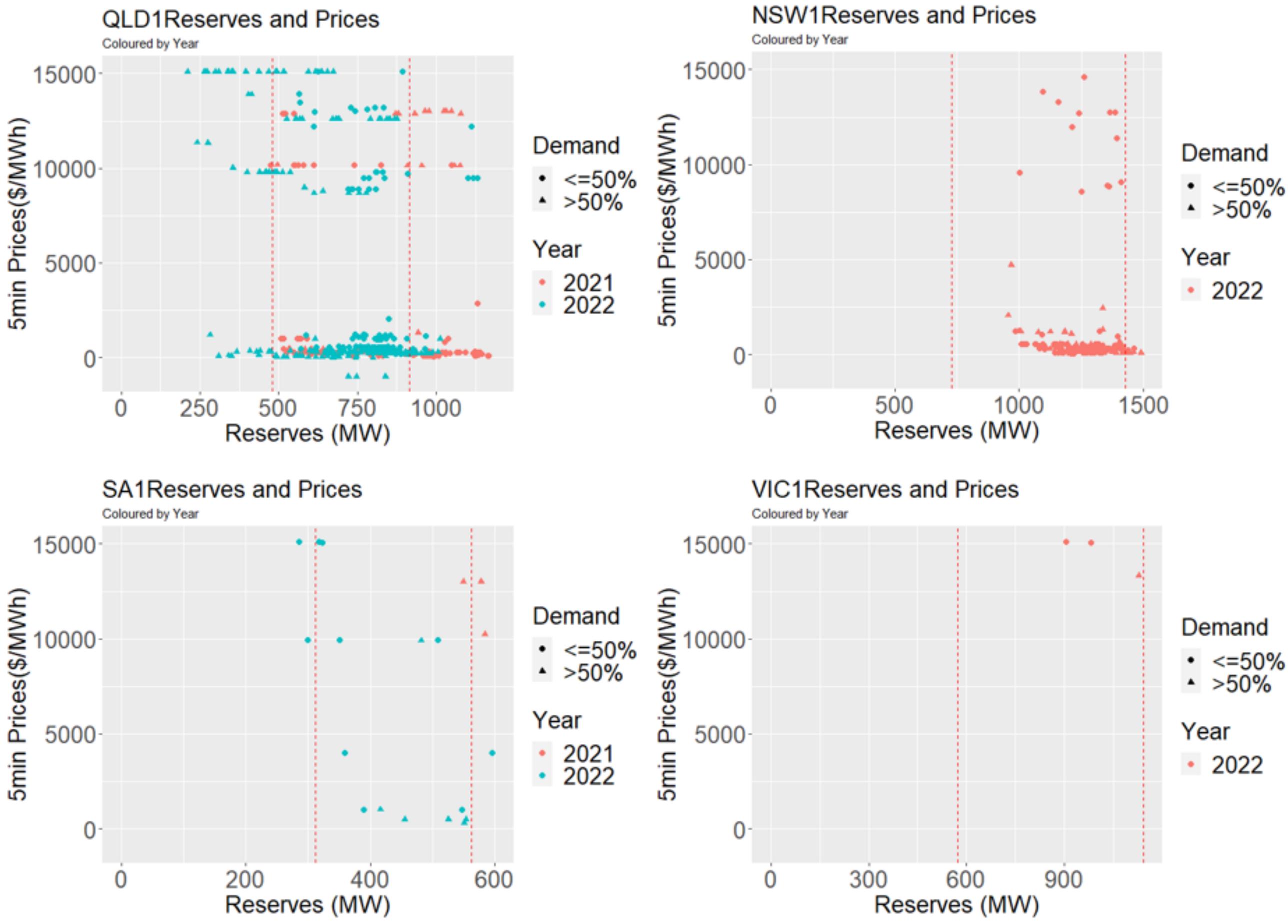


Figure 26 Price vs Reserve data for QLD (left) and NSW (right) LOR intervals following the implementation of 5-minute settlement. There is a significant number of intervals, even in the short period of time since 5MS, with low reserves (<LOR1), (<50th percentile, [circles]), and suppressed prices (significantly below MPC). Note that intervention pricing may have been in place for selected LOR intervals.

A2. Energy and operating reserves interactions with ramping

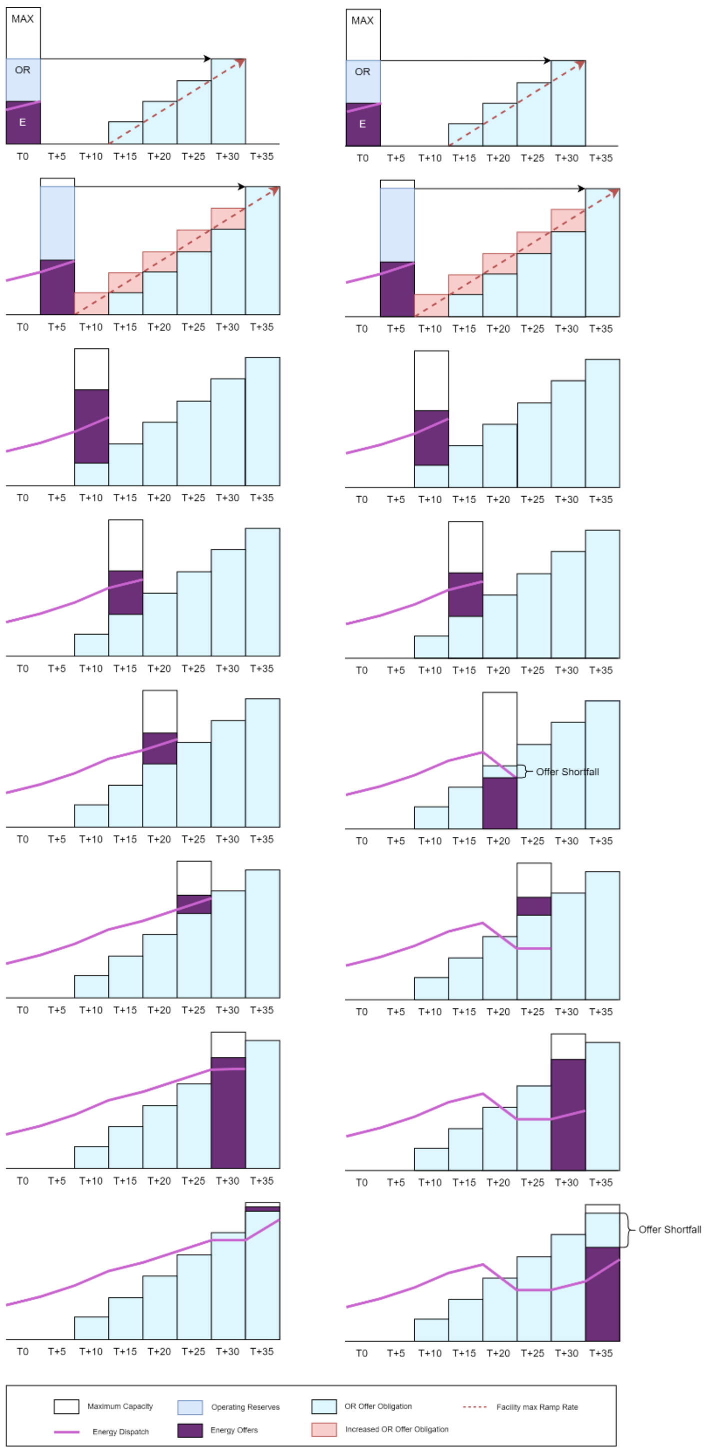


Figure 27. Energy and Operating Reserve interactions for a slow ramping Facility (Offer Obligation).

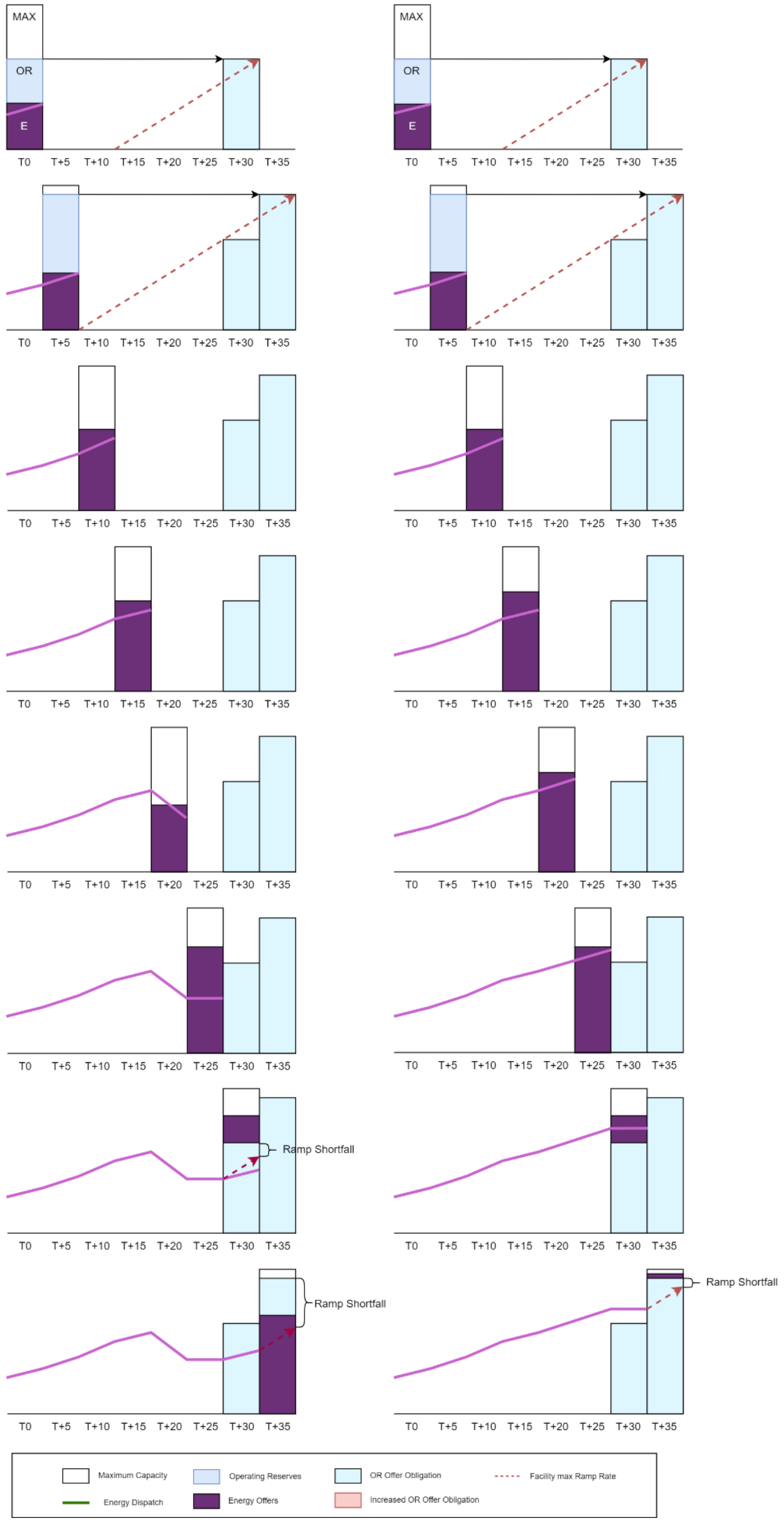


Figure 28. Energy and Operating Reserve interactions for a slow ramping Facility (Ramp Obligation).

A3. System-level worked example

This example is included to illustrate the mechanics of clearing a unit in the OR market, and how this creates headroom in the power system.

Context

Assumptions

This example is based on a hypothetical large ramp and large forecast error event. The example is roughly based on South Australia (SA) in a future with greater VRE capacity, and therefore greater forecast uncertainty, than the current system[30]. The event has been constructed with conditions (see next section) that would reasonably cause an OR market to clear at high prices, though ultimately this is still an assumption. Practical matters such as participant portfolio positions, the interaction of OR and energy markets, and details of OR design settings (such as the ORDC) could all influence the OR price but are not contemplated by the example.

System conditions

The following conditions are used in the worked example:

- Demand is relatively high and reserves are relatively low
- Victoria (VIC) is exporting to SA and the interconnector is binding
- The fleet is expecting to ramp to address demand rising and solar declining towards a 17:30 evening peak in SA
- Several fast-start gas generators are available but offline and not expecting to run
- A cloud band is expected to come over Adelaide metro area at approximately the same time as the predicted evening (sunset) ramp-down of PV
- However, the cloud band arrives ~20 minutes earlier than expected, resulting in PV forecast errors that are not captured by the 30-minute ahead forecast

[30] For reference, a recent example of a large forecast error event occurred on 6th November 2021 – an unexpected cloud front in SA saw a 400MW PV forecast error (rooftop only) on a half-hourly timescale. This worked example contains forecast errors of up to 1.4GW.

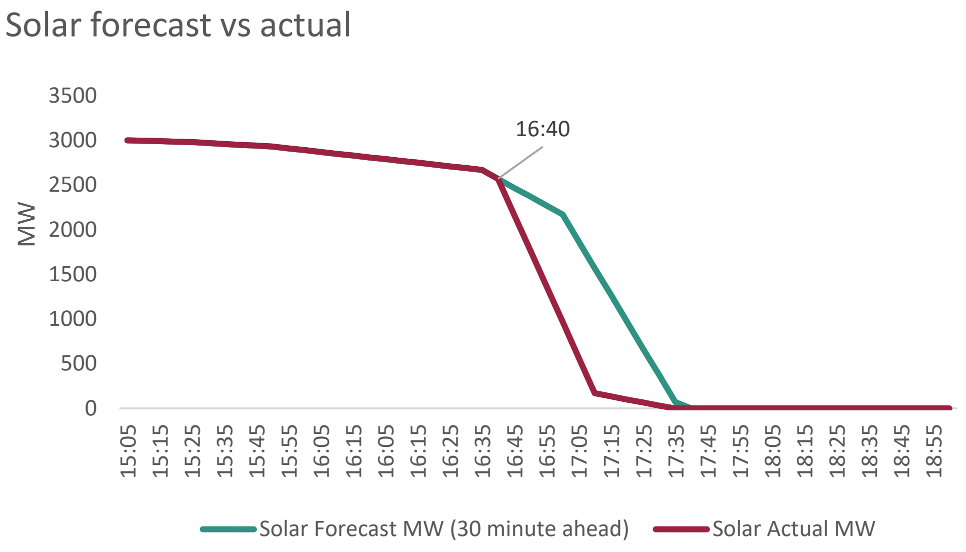


Figure 29 – Hypothetical scenario: solar forecast vs actual

Unit characteristics

This worked example follows a fast-start unit with the characteristics shown in Table 7. Similar units in SA include those at Ladbroke, Quarantine and Dry Creek power stations. For contrast, Table 8 describes other sources that could have been cleared in the OR market.

Table 7 - Indicative gas unit characteristics

Capacity	45MW
Minimum stable generation	5 MW
Time to synchronise and reach minimum stable generation	10 minutes
Ramp rate	8 MW/min (40 MW/interval)

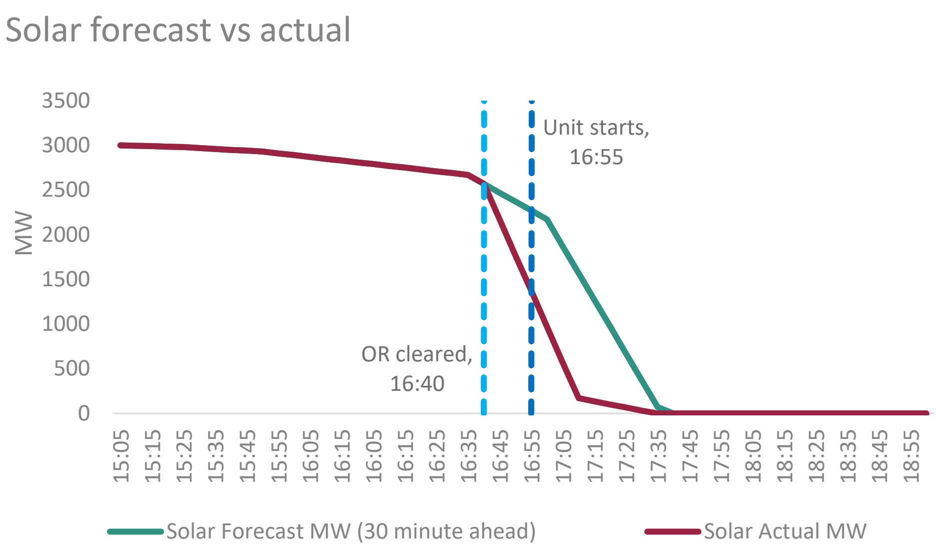
Table 8 - Alternative sources of OR relevant to worked example

Source	Comment
Batteries	• Are not restricted by ramp rates in meeting OR obligations • May be restricted by state of charge, and may therefore need to manage this through bidding between clearing and obligation
Curtailed VRE	• Is not restricted by ramp rates in meeting OR obligations

	• There is a design question as to how differences between forecast and actual headroom is accounted for – options include placing the compliance risk entirely on the participant, discounting VRE headroom or accounting for forecast error through cost recovery
Demand response (including WDR) and VPPs	• Large portion of demand side resources are off-market, an OR market would provide an incentive to participate in scheduling which would provide greater visibility and dispatchability. • Being scheduled to provide OR could provide 'notice period' to be ready to participate in 5-minute dispatch which may suit some large users.
Victorian generators	• A co-optimised OR product would import headroom if the cost of reducing interconnector flow to SA and increasing energy targets within SA was lower than any source of OR within SA • This could involve curtailing generation within VIC

Narrative

In the working product model, demand for OR is determined by the size of the expected net demand (i.e., demand to be met by dispatchable generation/demand response) ramp and uncertainty in the supply-demand balance 30-minutes into the future. With a solar down-ramp driven by a cloud front of uncertain timing forecast to commence at 17:00, it is reasonable to assume that the OR price would have risen by 16:40 (i.e., just before any forecast errors are observed).



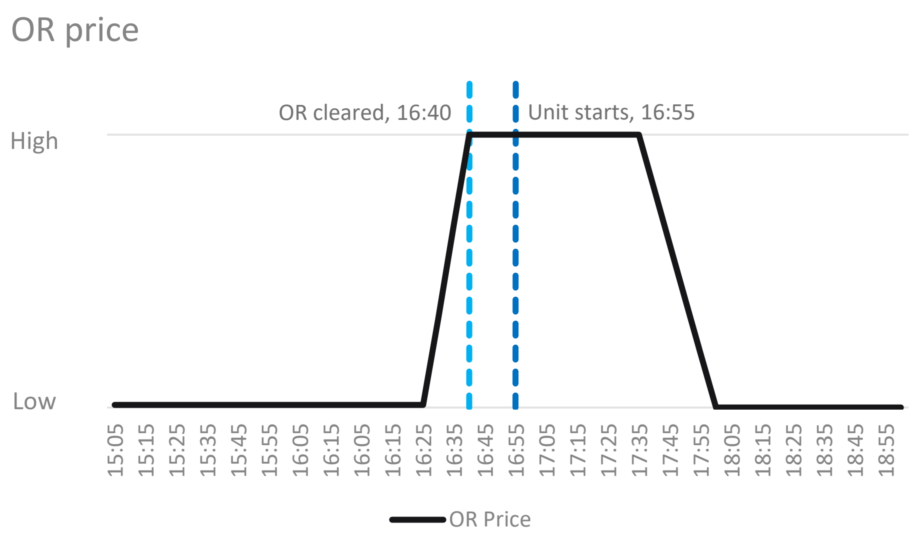


Figure 30 Solar forecast vs actual and OR price, with OR clearing and unit start times

Figure 30 assumes the 'high' OR price in interval ending 16:40 is sufficient to clear the example unit for its full output. As a result, the unit is given an obligation to be in a position to deliver its full output in interval ending 17:10[31]. Given a 10-minute start and sync time, and another 5 minutes to ramp to full output, the latest it can possibly start to be compliant with its OR obligations is 16:55. This is also marked on Figure 30.

By being online at its minimum generation level (5MW) from 17:05, the fast-start unit (with a 45MW maximum capacity) has brought online 40MW of additional generation. The unit's minimum generation will also displace 5MW from elsewhere in the fleet, thereby creating headroom on other units such that the net increase in online headroom equals the full capacity of the fast start unit. This is illustrated in Figure 31. For simplicity, the figure considers a 2-unit system consisting of the fast-start unit from the example and one thermal unit of the same size (45MW).

[31] Assuming the 'ramp obligation' and 'penalty for non-delivery' compliance options apply

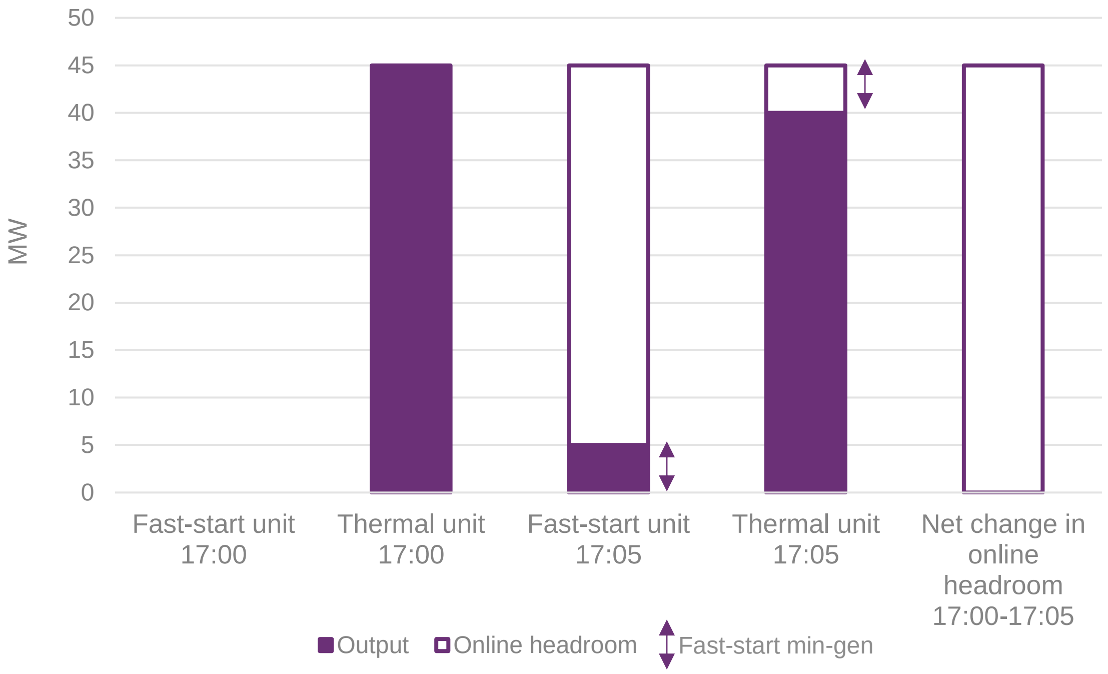


Figure 31 How an OR market creates headroom in a simplified fleet

The total impact of the OR market in terms of creating headroom in the system depends on:

- The aggregate volume of OR cleared through the market
- The technical characteristics of the cleared resources (see Table 8)
- The extent to which unbundling OR from energy prices has changed participant incentives