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Quantifying reserve capabilities for designing flexible electricity markets: An Australian case study with increasing penetrations of renewables

Abhijith Prakash [a,c,*], Rohan Ashby [b,c], Anna Bruce [b,c], Iain MacGill [a,c]

[a] School of Electrical Engineering and Telecommunications, UNSW Sydney, 330 Anzac Pde., Kensington, Sydney, 2052, NSW, Australia
[b] School of Photovoltaic and Renewable Energy, UNSW Sydney, Tyree Energy Technologies Building, 229 Anzac Pde., Kensington, Sydney, 2052, NSW, Australia
[c] Collaboration on Energy and Environmental Markets, UNSW Sydney, Tyree Energy Technologies Building, 229 Anzac Pde., Kensington, Sydney, 2052, NSW, Australia

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ABSTRACT

Across several power systems with market frameworks, policy-makers are proposing that balancing flexibility requirements emerging during energy transition be addressed through new reserve product markets. However, these may introduce additional costs, constraints and complexity, and even encroach upon the functions of existing operational practices. Thus, policy-makers need to assess and compare flexibility design options, and quantifying system flexibility capabilities based on current and expected resource mixes can assist in achieving this. In this article, we offer a practical method to quantify the time-varying spectrum of upwards and downwards flexibility capabilities in systems, and subsequently apply it to historical and projected resource mixes in two regions of the Australian National Electricity Market. Our results suggest that with higher penetrations of renewable energy: (1) downwards flexibility margins can be exhausted around noon if wind and solar are unable or unwilling to provide it, (2) upwards flexibility becomes more scarce during morning and evening peak demand events and (3) a greater portion of upwards flexibility is provided by energy-limited resources. Given these trends, we recommend that policy-makers examine how existing operational practices can be augmented to elicit upwards flexibility provision, and that duration specifications and sustained footroom procurement be considered for reserve products.

1. Introduction

The reliable and secure operation of power systems is contingent upon locational and temporal balancing of active power supply and demand. As jurisdictions progressively decarbonise electricity supply through considerable capacity additions of variable renewable energy (VRE) and the retirement of carbon-intensive conventional generation, the nature of short-term risks to system balancing (i.e. those of concern over the range of seconds to days) is changing. The most notable of these short-term risks are (Ela et al., 2011):

- Power system *variability*, which includes expected changes in the supply–demand balance. Traditionally, variability has been associated with system load movements and fluctuations around pre-determined generator schedules. As energy transition proceeds, system operators (SOs) are becoming increasingly focused on managing variability that arises due to the presence of VRE. This includes the correlated ramping of neighbouring solar PV generation during sunrise and sunset, and that of wind generation following the arrival of a cold front (Lew et al., 2013; Australian Energy Market Operator, 2020g).
- Power system *uncertainty*, which encompasses unexpected changes in the supply–demand balance. Beyond demand and VRE generation forecast errors, uncertainty also includes singular or widespread outage events that could be the result of a sudden loss of primary energy availability, equipment malfunctions, or common mode failures either triggered by insecure system operation (e.g. significant frequency and/or voltage deviations) or exogenous events (e.g. extreme weather events) (Redefining Resource Adequacy Task Force, 2021; Matevosyan et al., 2021; Electricity Sector Climate Information Project, 2021).

Provided that it is sufficient, leveraging the active power balancing flexibility of a power system (defined by Heggarty et al., 2020 as a system's "ability to cope with variability and uncertainty") should enable these short-term risks to be managed. At a particular point in time, the total balancing flexibility *capability* of a power system is the

* Corresponding author at: School of Electrical Engineering and Telecommunications, UNSW Sydney, 330 Anzac Pde., Kensington, Sydney, 2052, NSW, Australia.
E-mail address: abi.prakash@unsw.edu.au (A. Prakash).

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List of Abbreviations

AEMO	Australian Energy Market Operator
BESS	Battery energy storage system
CCGT	Combined-cycle gas turbine
DR	Demand response
FCAS	Frequency control ancillary services
Gas-Steam	Gas-powered steam turbine
ISP	Integrated System Plan
LOR	Lack of reserves
MSL	Minimum stable level
OCGT	Open-cycle gas turbine
NEM	National Electricity Market
NSW	New South Wales
PASA	Projected Assessment of System Adequacy
PV	Photovoltaic
RERT	Reliability and Emergency Reserve Trader
SA	South Australia
SO	System operator
SDP	Synthetic daily profile
UC-ED	Unit commitment and economic dispatch
VPP	Virtual power plant
VRE	Variable renewable energy

sum of potential flexibility contributions from resources such as generators, flexible demand and energy storage. However, the flexibility that can actually be *deployed* at any given time and location is potentially limited by:

1. Physical, economic, social and environmental constraints on the operation of resources (Denholm et al., 2018; Gonzalez-Salazar et al., 2018);
2. Network topology, particularly if deploying a flexibility solution results in the violation of network constraints (Lannoye et al., 2015; Liu et al., 2021); and
3. Operational practices. These include protocols and tools used by the SO (which is ultimately responsible for maintaining supply–demand balance) and electricity market design in power systems with a market overlay (Ela et al., 2016).

Though it is well established that operational practices are crucial to "enabling" balancing flexibility provision (Hirth and Ziegenhagen, 2015; Hsieh and Anderson, 2017; Papaefthymiou et al., 2018), limited attention has been given to assessing the trade-offs between practice changes (Mays, 2021). A typical design choice in power systems with electricity markets is determining whether a balancing function should be performed by the SO, or partially delegated to market participants via market-based mechanisms. Proponents of market-based mechanisms argue that if they are well-designed, their benefit is twofold: appropriate incentives can unlock the efficient utilisation of latent flexibility from existing resources whilst encouraging investment in additional flexibility as a market-signalled need emerges. However, to some extent, desires to maximise market benefits and minimise market distortions need to be weighed against providing the SO with sufficient lead-time and levers to maintain system balance during both normal and extraordinary circumstances (Roques, 2008; Prakash et al., 2022).

Establishing markets for balancing reserves offers a compromise between SO control and market efficiency (Ryan et al., 2014; Kristov et al., 2016). These enable the SO to set a requirement for, competitively procure and then schedule system *headroom* (spare generation capacity and potential load curtailment) or system *footroom* (potential generation curtailment and load increase) with particular power, energy, ramping and quality-of-response (e.g. response time) capabilities (Ulbig and Andersson, 2015; Degefa et al., 2021). Whilst tailored *reserve services* can be procured through tendering processes, zonal or system-wide markets for *reserve products* have become increasingly commonplace given that temporal balancing is of greater concern in meshed networks. Additionally, "commodification" of capabilities through products reduces complexity and enables the implementation of auctions, which can improve transparency and competition and be co-optimised with energy or other reserve product markets (Mancarella and Billimoria, 2021; Lal et al., 2021).

The changing nature of short-term risks to system balancing and the accompanying need for greater system flexibility is leading policy-makers to reassess the suitability of the reserve products available to their SOs (EU-SysFlex, 2019; Energy Security Board, 2021; Federal Energy Regulatory Commission, 2021). Reform of reserve arrangements can simply modify procurement practices or lead to a more significant restructuring of available products, which includes introducing new markets (Ryan et al., 2014). Particularly in their initial stages, reform processes tend to justify changes on the basis of how they might address potential threats to system balancing. This approach is appropriate and sufficient where reserve service provision entails specialised quality-of-response capabilities that cannot be provided effectively or efficiently through other means (e.g. high bandwidth control configurations required for fast frequency response provision). However, some reserve products may "compete" with other design options. For example, the purpose and timeframe of tertiary frequency control and ramping products overlap with those of dispatch processes. Where reserve arrangement reform encroaches on the functions of other processes and practices, quantifying system flexibility capabilities based on current and expected resources mixes can assist policy-makers in assessing flexibility design options.

Reserve products also impose tangible and intangible costs. Regardless of cost allocation mechanisms, procuring reserves typically raises system operation costs and thus prices paid by energy users (Hummon et al., 2013). Furthermore, even if they offer a solution to a system sub-problem, reserve products do not guarantee reliable operation of the overall system and may even hinder the implementation of other measures that can realise system flexibility (Papaefthymiou et al., 2018; Pollitt and Anaya, 2019; MacGill and Esplin, 2020). For example, valuing balancing flexibility on the scale of minutes to hours through reserve products could mean sacrificing the benefits of better reflecting the value of flexibility in energy prices:

1. For participants, energy market risk management is more straightforward than managing risk in reserve product markets. Short-term energy markets typically have greater depth and a broader range of associated technical or financial forward markets (Pollitt and Anaya, 2019).
2. Reserve product markets often have pre-qualification criteria and minimum offer quantities. As such, the participation of smaller demand-side and distributed energy resources (DER) in reserve product markets is often contingent on the involvement of an intermediary aggregator, which imposes additional transaction costs (Poplavskaya and de Vries, 2019). However, embedding the value of flexibility within the price for energy could simplify flexibility provision through market participation for these resources, particularly if policy-makers pursue dynamic retail pricing or nested distribution-level markets that interface with transmission-level markets (Kristov et al., 2016; Hogan, 2019; Mays, 2021).
3. The flexibility that the SO is able to procure through reserve products is restricted by their product specifications. Solely relying on reserve products for flexibility may constrain operational outcomes. Such flexibility "discretisation" might also be reflected in the resources deployed in the system should reserve product markets influence investment decisions (Lal et al., 2021). Additionally, whilst reserve products can be tailored

to a particular system's capabilities and needs, reserve sharing between SO jurisdictions is easier if technical specifications are standardised (Scherer, 2016).

Given these factors, quantification and comparison are therefore needed to assess the role of reserve products, particularly where (Rebours et al., 2007; Ela et al., 2021):

1. Other operational practice or policy changes have the potential to deliver greater and/or more robust flexibility benefits without the additional costs, uncertainty and complexity of new markets; or
2. Current market design or exogenous resource adequacy policies (e.g. firming revenue guarantees or capacity markets) are driving sufficient investment in flexible resources.

A plethora of metrics that quantify different aspects of system balancing flexibility capabilities have been proposed in the literature (Lannoye et al., 2012b; Mohandes et al., 2019; Heggarty et al., 2020). Rather than solely quantifying flexibility capabilities, operational metrics typically compare short-term flexibility capabilities against a flexibility requirement that is set by one of the following or a combination thereof: rules-of-thumb, net load variability, net load forecast uncertainty and/or probabilistic VRE forecasts. While a SO can use these metrics to identify potential flexibility shortages (Zhao et al., 2016), dimension reserve products (Dvorkin et al., 2014; Costilla-Enriquez et al., 2023) or schedule resources (Nosair and Bouffard, 2015), they may be less useful to system designers assessing changes to practices that leverage decentralised decision-making (e.g. energy and reserve product markets). Broader planning-oriented flexibility capability metrics may be more suitable for such purposes. These include traditional resource adequacy metrics (Stenclik et al., 2021), "inflexibility costs" (e.g. additional system costs due to flexibility constraints as explored in Vithayasrichareon et al. (2017)) or "flexibility adequacy" metrics, such as the insufficient ramping resource expectation proposed in Lannoye et al. (2012a). In particular, Lannoye et al. (2012a) uses time-sequential power system operations data to explicitly calculate the balancing flexibility available after resources are dispatched, though valuable chronological information is lost when the time series generated in the study are converted into probability distributions to calculate the insufficient ramping resource expectation. By retaining a degree of this chronological information, our methodology aims to provide electricity industry stakeholders with a better understanding of the time-varying "spectrum" of system balancing flexibility capabilities, and thus assist them in assessing, comparing and designing potential operational practice changes to improve flexibility in power systems with a growing number of variable and energy-limited resources.

In this article, we offer a practical method for quantifying available reserves and footroom (the balancing flexibility that is available after resources are dispatched to meet system demand), and an example of how such quantification can inform flexible electricity market design. We provide simple extensions to the methodology developed by Lannoye et al. (2012a) that account for flexibility contributions from VRE and battery energy storage systems (BESS), and market participants' aversions to incurring cycling costs. We then use this methodology in a case study in which we quantify time-varying available reserves and footroom in real-world systems: two regions of the Australian National Electricity Market (NEM). Through a 2020 baseline and two 2025 scenarios, we test four key sensitivities in these two regions: the acceleration of large conventional generation retirement, the rate of deployment of VRE and storage technologies, contrasting resource mixes and operational constraints, and greater variability in operational demand. While previous studies have tested the impact of some of these sensitivities on the availability of total system headroom or existing reserve products (Hummon et al., 2013; Tanoto et al., 2021; Frew et al., 2021), our analysis offers a perspective that is focused on quantifying a time-varying spectrum of flexibility capabilities and thus concerned with the *design* of operational practices in low-carbon power systems. Our analysis results highlight the underappreciated need to consider mechanisms for procuring footroom, and we proceed to discuss the implications of implementing new balancing products on operational outcomes. Though the NEM is unique in aspects of its operational practices and the balancing risks it faces, the methodology and findings from this study will become increasingly relevant in other jurisdictions given the accelerating deployment of VRE and storage and the progressive retirement of carbon-intensive conventional generation (International Energy Agency, 2019, 2021).

Section 2 provides an overview of how balancing flexibility is enabled and procured through the NEM's operational practices and market design. In Section 3, we describe a methodology to quantify available reserves and footroom across deployment horizons for various resource types. Then, in Section 4, we quantify the available reserves and footroom in two regions of the NEM for existing resource mixes in 2020 and potential resources mixes in 2025, with two scenarios for the latter. We then use the findings from this case study to explore the role of reserve products in securing balancing flexibility. We conclude by highlighting pertinent findings and recommendations to policy-makers in Section 5.

2. Flexibility in the National Electricity Market

The Australian National Electricity Market (NEM) is a short-term wholesale electricity market overlaid on a ~5000 kilometre long "stringy" network that services the majority of eastern and southern Australia (Australian Energy Market Commission, 2022a). In 2021, it saw a peak demand of ~32 GW and total electricity consumption of ~204 TWh (Australian Energy Regulator, 2022). With no explicit capacity mechanisms or compulsory forward markets, the NEM solely consists of a zonal real-time platform, with market regions corresponding to the states of Queensland, New South Wales (NSW), Victoria, Tasmania and South Australia (SA). Interconnection between market regions is relatively weak and, due to the large distances involved, the NEM is not connected to other bulk power systems (Australian Energy Market Operator, 2019c).

In the subsections that follow, we describe the operation of the NEM with a focus on features and mechanisms that enable or explicitly procure balancing flexibility. In particular, we discuss current reserve arrangements in the NEM in Section 2.3 and the proposal to introduce an *operating reserve* product in Section 2.3.1. The policy debate surrounding the usefulness and design of this potential reserve product provides the primary motivation for our case study in Section 4.

2.1. Market design

2.1.1. Real-time markets

The NEM is a central dispatch market that is operated by the Australian Energy Market Operator (AEMO). On the day ahead of delivery, market participants are required to submit non-binding offers for each resource consisting of price-quantity pairs for energy and, optionally, Frequency Control Ancillary Services (FCAS) (described in Section 2.3) (Australian Energy Market Operator, 2021e). Energy offers can be priced as high as the market price cap (15,000 AUD/MW/hour during the Australian financial year of 2020–2021) or as low as the market floor (−1000 AUD/MW/hour). Negative pricing enables generators to express a preference to either remain online due to significant start-up/shut-down costs or to be dispatched as a price-taker when it is commercially favourable to do so (e.g. to receive remuneration from an offtake agreement). In theory, it also provides investment signals for flexible resources alongside a relatively high market price cap (Riesz et al., 2016; Orvis and Aggarwal, 2018).

On the day of delivery, co-optimised markets for energy and FCAS are cleared every 5 min through a security-constrained economic dispatch process, which produces zonal marginal prices for energy and

FCAS. There is no formal gate closure in the NEM; participants are able to alter volumes (but not prices) in their offer up to tens of seconds before the delivery interval (Australian Energy Market Commission, 2015; Paul McArdle, 2021). In 2021, the market settlement period was changed from 30 min (the average of prices of the preceding six 5-minute intervals) to 5 min to better align settlement with dispatch and pricing (Australian Energy Market Operator, 2022a). Since resources are expected to linearly ramp between one dispatch target and the next, the dispatch process implicitly "procures" some flexibility to manage variability (Ryan et al., 2014; Australian Energy Market Operator, 2021a). As such, the NEM's dispatch is relatively fast and granular when compared to short-term electricity markets worldwide (Katz et al., 2019; Silva-Rodriguez et al., 2022).

The NEM's real-time market is also able to elicit balancing flexibility provision from a variety of resources:

- Unlike some North American markets that permit large proportions of the generation fleet to self-schedule (Ela et al., 2016; Orvis and Aggarwal, 2018), generation with a capacity above 30 MW is required to participate in the real-time market and receive dispatch instructions (Australian Energy Market Commission, 2017). This exposes larger utility-scale resources, which make up the bulk of the NEM's generation capacity, to price signals that somewhat reflect system balancing requirements.
- VRE forecasts used in dispatch can be generated by AEMO or provided by market participants; due to very late gate closure, both are able to incorporate telemetered operational data from the minutes preceding delivery (Australian Energy Market Operator, 2016, 2018b).
- In 2021, a wholesale demand response mechanism was implemented to enable larger loads (aggregated or otherwise) and virtual power plants (VPPs) to directly participate in the energy market[1] (Australian Energy Market Operator, 2020i).

2.1.2. Forward markets

In the NEM, forward energy markets are voluntary and primarily consist of the trading of electricity derivatives between market participants. Though market participants can contract over-the-counter, the majority of forward market activity occurs on two market exchanges for standard products for periods up to 3 years out (ASX Energy, 2021; Australian Energy Regulator, 2021). These standard products include quarterly or annual futures, which fix a price for an agreed quantity of energy, and caps, which are essentially call options that enable contract purchasers (typically electricity retailers) to pay no more than the strike price of 300 AUD/MWh for energy at the cost of a premium paid to the seller. Contract markets in SA are considered to be relatively illiquid compared to those in NSW, Queensland and Victoria (Australian Energy Regulator, 2022). Beyond enabling market participants to hedge real-time market price risk, products traded on the forward markets may 'discipline' market participants into offering balancing flexibility to the system. For example, a generating market participant that sells futures and caps is likely to retain some reliable generation capacity in reserve to avoid large payouts in the event of high real-time prices or the failure of their other plants (Riesz et al., 2016).

2.1.3. Limitations

Despite the arguably world-leading flexible design of its real-time markets, there are some notable limitations in the NEM and its associated forward markets:

- To date, the balancing flexibility offered by DER has primarily been leveraged through unremunerated, last-resort curtailment of distributed solar PV in SA by AEMO (Australian Energy Market Operator, 2021c) or through aggregated solar-battery VPPs. At the end of 2021, VPPs had a registered capacity of approximately 30 MW (Kuiper, 2022), a small percentage of the ~15 GW of distributed solar PV capacity installed in the NEM as of June 2022 (Australian PV Institute, 2022).
- Aside from the procurement of footroom that is only deployed following frequency excursions (Section 2.3), there are currently no mechanisms in the NEM that remunerate resources for providing sustained downwards flexibility to the system.
- Standard derivative products have remained much the same for decades despite changes in the NEM's resource mix and market dynamics. In particular, the 300 AUD/MWh strike price of cap contracts does not necessarily reflect a resource's operating costs (e.g. the price of natural gas or the charging/pumping price for BESS/pumped hydro energy storage). While a demonstration project trialled a market platform for derivatives designed to be sold by flexible resources (e.g. a "Super Peak" contract that enables buyers to hedge morning and evening demand peaks), these are nascent products with small traded volumes to date (Renewable Energy Hub, 2021).
- AEMO has little visibility and no direct oversight over the voluntary forward markets, which are currently operated by the financial services sector. Moreover, even if AEMO did, it would likely be difficult for them to determine how portfolio-based contracting might influence the operation of particular resources (Australian Energy Market Commission, 2020).

2.2. Ahead processes and operator intervention

Through several ahead processes, AEMO regularly publishes forecasted system and market information to assess power system reliability and assist market participant decision-making. The processes most relevant to operational decision-making include the near-term Projected Assessment of System Adequacy (PASA) and pre-dispatch simulations:

- Using forecasts for demand and VRE, a simplified set of forecasted network constraints and participant-submitted resource availabilities and energy constraints, the Pre-Dispatch PASA and Short Term PASA (run every half-hour and hour, respectively) both assess the maximum generation reserves available in each region for the next 7 trading days. PASA outputs include half-hourly available generation and system load forecasts (Australian Energy Market Operator, 2012, 2020f; Australian Energy Market Commission, 2022b).
- Once day-ahead offers have been submitted by market participants, AEMO uses these offers in pre-dispatch processes alongside forecasts for constraints, demand and VRE. Pre-dispatch simulations then produce forecasts for dispatch conditions and regional prices for energy and FCAS. These are run every half hour at half-hourly resolution until the end of the next trading day (pre-dispatch) and at 5 min resolution for the next hour (5 min pre-dispatch) (Australian Energy Market Operator, 2022b, 2021e). The potential impacts of demand forecast error on regional energy prices and interconnector flows are explored through a sensitivity analysis (Australian Energy Market Operator, 2021d).

Regional balancing stress is indicated by the level of in-market reserves, which is the total offered generation capacity in excess of forecast regional demand.[2] Should the Short Term PASA or pre-dispatch processes forecast in-market reserves below specific trigger levels, AEMO must issue market notices that declare forecast Lack of Reserve (LOR) conditions (Australian Energy Market Operator, 2021g). Trigger

[1] Many of these resources were previously restricted to FCAS provision.

[2] This measure does not consider the horizon within which the capacity can be converted to generation (i.e. the reserve horizon).

levels are set by the maximum of either deterministic generation contingencies (i.e. below N-2 for LOR1, below N-1 for LOR2 and no in-market reserves for LOR3), or a particular confidence level of a probability distribution of total forecasting errors generated by a Bayesian Belief Network, which is trained on historical forecast errors and power system conditions (Australian Energy Market Operator, 2018a).

The intention of these ahead process and LOR notices is to provide market participants with information that might elicit a response, such as shifting planned maintenance or rescheduling flexible resources in response to forecasted tight supply–demand balance conditions. However, if more severe LOR2 or LOR3 notices have been issued and AEMO deems that the market response is insufficient by a certain time, AEMO can intervene in the market by issuing directions (manual dispatch), activating emergency reserves procured through the Reliability and Emergency Reserve Trader (RERT) and/or instructing transmission network operators to shed load (Australian Energy Market Operator, 2021g, 2018a).

2.3. Reserve products

Formal reserves arrangements in the NEM consist of eight FCAS and the Reliability and Emergency Reserve Trader (RERT). In each dispatch interval, FCAS are procured by AEMO from markets for raise (headroom) and lower (footroom) regulation FCAS, which are used to provide frequency control during normal operation, and three raise and lower contingency FCAS, which deliver their full response within 6 s, 60 s or 5 min following a major imbalance event. The volumes of FCAS procured for each dispatch interval are dynamically determined, with regulation FCAS procurement volumes dictated by power system time error and contingency FCAS procurement volumes typically corresponding to an N-1 contingency. In the absence of regional constraints, FCAS are procured for and from all regions of the NEM. While FCAS provide balancing flexibility through frequency-responsive headroom and footroom, they predominantly respond to intra-dispatch variability and uncertainty with the expectation that deployed resources will be relieved by 5-minute dispatch (Riesz et al., 2015; Prakash et al., 2022). 5 min contingency FCAS is an exception, given that its response may be called upon for up to 10 min. 5 min contingency FCAS is currently provided by a diverse range of resources (see Fig. 1).

Through the RERT, AEMO can obtain last-resort reserves given between 1 week to 1 year of notice of forecasted in-market reserves shortfalls. While procurement practices vary depending on the notice time, RERT procurement consists of AEMO contracting with out-of-market resources. Following forecast or actual LOR2 or LOR3 conditions and an insufficient market response, AEMO is able to activate RERT reserves (Australian Energy Market Commission Reliability Panel, 2020; Australian Energy Market Operator, 2021f). The RERT provides AEMO with a last-resort mechanism to procure balancing flexibility prior to any potential load shedding. However, resources that provide reserves through the RERT are unable to participate in the real-time market for the duration of their contract. After RERT reserves are activated, market participants are remunerated based on counterfactual pricing (i.e. dispatch without RERT), thus maintaining scarcity pricing and potential signals for investment.

2.3.1. Operating reserves product

An inter-dispatch operating reserve product has been proposed in the NEM. It would enable AEMO to procure headroom, which would need to be available to the real-time market within the product horizon, in each dispatch interval. Horizons of 5 min and 30 min were proposed (Energy Security Board, 2021; Australian Energy Market Operator, 2021h). Market bodies and participants have raised several potential benefits of an operating reserve product:

1. It could address both inter-dispatch variability and uncertainty. Market bodies consider that the need to address the latter may be more material due to the growing impact of forecast uncertainty on system balancing and the potential for high impact, low probability power system events leading to extraordinary system imbalances (Eggleston et al., 2021; Australian Energy Market Commission, 2021).
2. AEMO supports a 30+ min horizon, as a longer timeframe product is likely to have a larger pool of providers and provide participants/AEMO with more lead time prior to any potential market intervention (Australian Energy Market Operator, 2021h).
3. Through reserve constraints and potential scarcity pricing through an operating reserve demand curve (Hogan, 2013), the product could act as an energy 'price-adder'. This would enable real-time market prices for energy to better reflect consumers' preference for reliability (Cramton, 2017). Although the NEM's market price cap is high by international standards, it is generally well below the estimated value of short-term reliability for both residential and non-residential customers in the NEM (Australian Energy Regulator, 2019). A 'price-adder' could also provide sharper investment signals for flexible resources.

The assessment of reserve capabilities to justify this new product has been limited. AEMO has previously analysed ramping capabilities over timeframes greater than 30 min (Australian Energy Market Operator, 2020g), the total reserve capacity available within various timeframes across NEM regions and years (Australian Energy Market Operator, 2021h) and regularly forecasts in-market reserves (Section 2.2). However, these studies do not consider flexibility capability available *after* resources are dispatched, or do not explore the time-varying spectrum of this capability. Using the methodology outlined in Section 3, we incorporate these elements when quantifying balancing flexibility capabilities in NSW and SA to inform an assessment of the operational benefits of additional balancing products (Section 4).

3. Modelling available reserves and footroom

To quantify balancing flexibility capabilities, we consider headroom and footroom that can be converted to stable active power output within a particular time *horizon*. We will refer to these as *available reserves* and *available footroom*,[3] respectively. Though these metrics do not explicitly consider whether resources are frequency-responsive, how long a potential response can be sustained for and whether network constraints restrain flexibility provision, calculating these quantities is broadly useful for understanding the balancing flexibility that could be deployed in a meshed system within operational timeframes (minutes to hours).

3.1. Quantifying available reserves and footroom

At a given point in time and for a particular horizon, the available reserves and footroom that a resource can offer are dependent on its operational constraints, its synchronisation status and its active power output. The latter two can be obtained from historical data, or as the outputs of production-cost or market modelling.

Below, we outline a methodology for calculating system-wide available reserves and footroom (Section 3.1.5). We adapt the methodology proposed by Lannoye et al. (2012a) to calculate available reserves and footroom from conventional resources (coal-fired, hydro and gas-fired

[3] We use terminology consistent with Lannoye et al. (2015), which quantifies *available* flexibility considering resource operational constraints and *realisable* flexibility considering both network and resource operational constraints. These types of flexibility exclude transient power changes from phenomena such as inertial response.

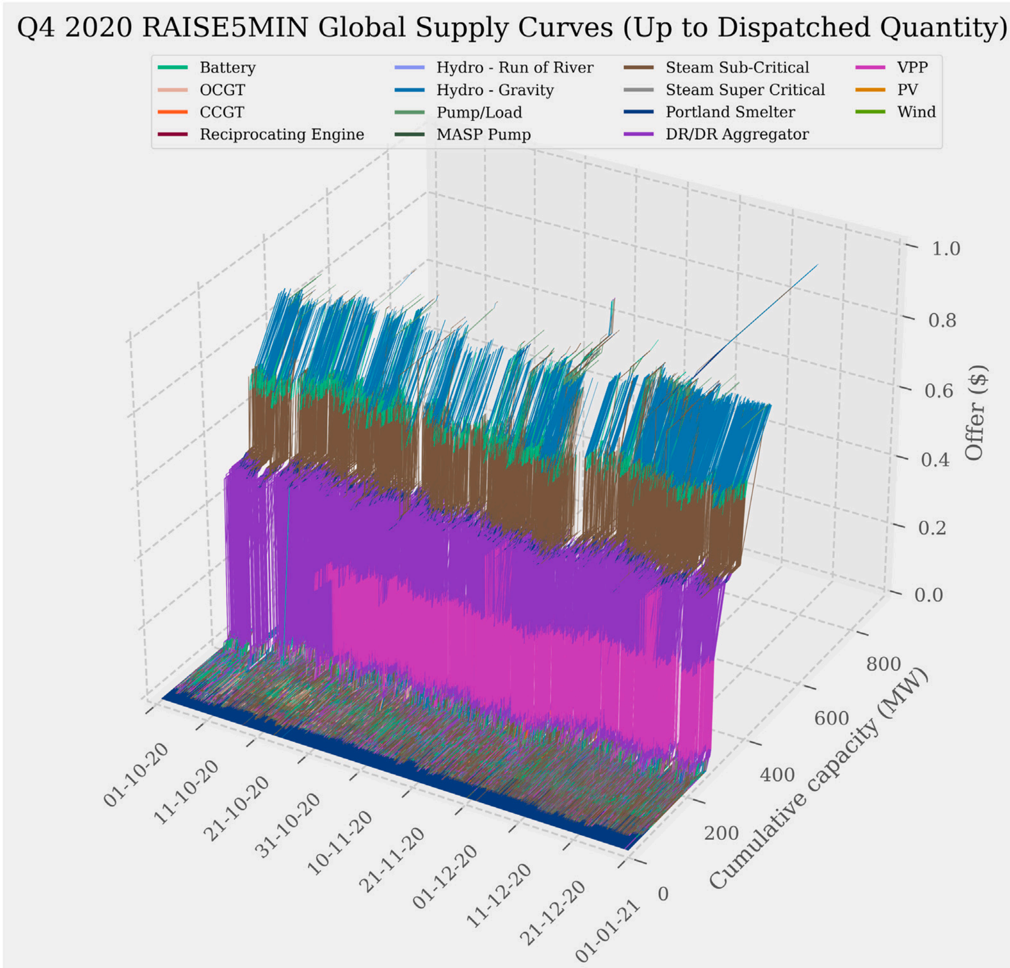


Fig. 1. Q4 2020 global supply curves by resource type for the raise 5 min contingency FCAS market. Each of the supply curves are truncated to the volumes of 5 min contingency FCAS procured by AEMO across the NEM in that dispatch interval (NEM-wide mean of ∼420 MW for Q4 2020). Providers include conventional steam and hydropower generators, an aluminium smelter, demand response (DR) aggregators, VPPs and BESS. As each supply curve is constructed from the offers of resources across the NEM (i.e. global), they do not reflect dispatch outcomes in the presence of regional constraints. Offer and dispatch data were obtained using NEMOSIS (Gorman et al., 2018).

generation - Section 3.1.2), and propose simple extensions for calculating available reserves and footroom provided by VRE (Section 3.1.3) and BESS (Section 3.1.4). The nomenclature used in these sections is described in Section 3.1.1.

3.1.1. Nomenclature

3.1.1.1 Indices and sets

$t \in \mathcal{T}$ Time periods, each corresponding to the end of a 5-minute dispatch interval in the corresponding scenario year.

$h \in \mathcal{H}$ Set of (reserve) horizons (min).

$r_c \in \mathcal{R}_c$ Set of conventional resource units.

$r_v \in \mathcal{R}_v$ Set of VRE resource units.

$r_b \in \mathcal{R}_b$ Set of BESS resource units.

3.1.1.2. Time-varying resource parameters

$g_{r_c/r_v/r_b,t}$ Net generation (active power output) of unit at time t (MW).

$g^f_{r_v,t}$ Maximum generation of VRE resource unit based on primary energy availability, i.e. $0 \leq g^f_{r_v,t} \leq \overline{g}_{r_v,t}$ (MW).

$\overline{g}_{r_c/r_v/r_b,t}$ Maximum capacity of unit. Time-varying due to seasonal derating and partial/full outages (MW).

3.1.1.3. Static resource parameters

MSL_{r_c} Minimum stable level of conventional resource unit r_c (MW).

$\mathrm{StartUp}_{r_c}$ Start-up ramp up rate of conventional resource unit r_c. Start-up is assumed to progress in a linear fashion (MW/min).

RampUp_{r_c} *Upper* ramp up rate of conventional resource unit r_c. See Section 4.2 for an explanation of *upper* ramp rates (MW/min).

$\mathrm{RampDown}_{r_c}$ *Upper* ramp down rate of conventional resource unit r_c. See Section 4.2 for an explanation of *upper* ramp rates (MW/min).

3.1.1.4. Computed quantities

$\mathrm{SUT}_{r_c,t}$ Start-up time for conventional resource unit, i.e. $\mathrm{SUT}_{r_c,t} = \frac{\mathrm{MSL}_{r_c} - g_{r_c,t}}{\mathrm{StartUp}_{r_c}}$ where $0 \leq g_{r_c,t} < \mathrm{MSL}_{r_c}$ (min).

$AR_{r_v,h,t}$ Available reserves from VRE resource unit r_v at time t for horizon h (MW).

$AR_{r_b,h,t}$ Available reserves from BESS resource unit r_b at time t for horizon h (MW).

$AR^{OFF}_{r_c,h,t}$ Available reserves from offline conventional resource unit r_c at time t for horizon h (MW).

$AR^{ON}_{r_c,h,t}$ Available reserves from online conventional resource unit r_c at time t for horizon h (MW).

$AR_{h,t}$ Reserves available to the system within horizon h at time t (MW).

$AF_{r_v,h,t}$ Available footroom from VRE resource unit r_v at time t for horizon h (MW).

$AF_{r_b,h,t}$ Available footroom from BESS resource unit r_b at time t for horizon h (MW).

$AF^{ON}_{r_c,h,t}$ Available footroom from online conventional resource unit r_c at time t for horizon h (MW).

$AF_{h,t}$ Footroom available to the system within horizon h at time t

3.1.2. Conventional resources

The quantities of reserves and footroom that can be made available by conventional resources are dependent on whether the resource is online (non-zero active power output) or offline.

A conventional resource unit is considered to be online if $g_{r_c,t} > 0$. The reserves that an online conventional resource unit can make available within the horizon h ($AR^{ON}_{r_c,h,t}$) is given by:

$$AR^{ON}_{r_c,h,t} = \begin{cases} \text{StartUp}_{r_c} \times h & 0 < g_{r_c,t} < \text{MSL}_{r_c}, h \le \text{SUT}_{r_c,t} \\ \min(& \\ \quad (\text{MSL}_{r_c} - g_{r_c,t}) + \text{RampUp}_{r_c} \times (h - \text{SUT}_{r_c,t}), & \\ \quad \overline{g}_{r_c,t} - g_{r_c,t} & \\ ) & 0 < g_{r_c,t} < \text{MSL}_{r_c}, h > \text{SUT}_{r_c,t} \\ \min(\text{RampUp}_{r_c} \times h, \overline{g}_{r_c,t} - g_{r_c,t}) & g_{r_c,t} \ge \text{MSL}_{r_c} \end{cases} \tag{1}$$

The three conditions in Eq. (1) reflect the following:

1. The unit is in its start-up sequence (i.e. $0 < g_{r_c,t} < \text{MSL}_{r_c}$) and the reserve horizon (h) is shorter than or equal to the unit's start-up time ($\text{SUT}_{r_c,t}$). In this case, the start-up ramp rate (StartUp_{r_c}) dictates the quantity of reserves that the unit can provide.
2. The unit is in its start-up sequence and the reserve horizon (h) is longer than the unit's start-up time ($\text{SUT}_{r_c,t}$). In this case, the quantity of reserves that the unit can provide is the minimum of the total unit ramping potential within the reserve horizon (at rate StartUp_{r_c} up to the unit's minimum stable level, and RampUp_{r_c} beyond it) and the unit's headroom.
3. The unit is operating above its minimum stable level. The quantity of reserves that the unit can provide is the minimum of the total unit ramping potential within the reserve horizon (at rate RampUp_{r_c}) and the unit's headroom.

The reserves that an offline conventional resource unit can make available within the horizon h is given by Eq. (2), which has two conditions that resemble the first two conditions of Eq. (1):

$$AR^{OFF}_{r_c,h,t} = \begin{cases} \text{StartUp}_{r_c} \times h & g_{r_c,t} = 0, h \le \text{SUT}_{r_c,t} \\ \min(& \\ \quad \text{MSL}_{r_c} + \text{RampUp}_{r_c} \times (h - \text{SUT}_{r_c,t}), & \\ \quad \overline{g}_{r_c,t} - g_{r_c,t} & \\ ) & g_{r_c,t} = 0, h > \text{SUT}_{r_c,t} \end{cases} \tag{2}$$

To ensure that flexibility quantification only considers stable changes in active power output, footroom from conventional resource units is defined to be the maximum downwards flexibility they can provide without shutting down (i.e. down to their MSL). As such, footroom can only be provided by online units operating above their MSL (first condition in Eq. (3)):

$$AF^{ON}_{r_c,h,t} = \begin{cases} \min(\text{RampDown}_{r_c} \times h, g_{r_c,t} - \text{MSL}_{r_c}) & g_{r_c,t} > \text{MSL}_{r_c} \\ 0 & 0 < g_{r_c,t} \le \text{MSL}_{r_c} \end{cases} \tag{3}$$

3.1.3. Variable renewable energy

Within the availability of their primary energy source and the timeframes of concern in this study, VRE are considered to be highly flexible (Nelson et al., 2018; Holttinen et al., 2021). Therefore, the provision of available reserves ($AR_{r_v,h,t}$) and footroom ($AF_{r_v,h,t}$) by VRE is not limited by ramp rates but rather by headroom and footroom:

$$AR_{r_v,h,t} = g^f_{r_v,t} - g_{r_v,t} \tag{4}$$

$$AF_{r_v,h,t} = g_{r_v,t} \tag{5}$$

In this study, $g_{r_v,t} < g^f_{r_v,t}$ can occur as the result of VRE curtailment due to oversupply.

3.1.4. Battery energy storage systems

BESS are also highly flexible and, unlike other resource types, can provide additional flexibility by switching from charging ($g_{r_b,t} < 0$) to discharging ($g_{r_b,t} > 0$), or vice-versa. This additional flexibility can be accounted for by including the maximum power capacity of the BESS ($\overline{g}_{r_b,t}$, which restricts BESS charging and discharging such that $|g_{r_b,t}| \le \overline{g}_{r_b,t}$) in the equations for available reserves (Eq. (6)) and available footroom (Eq. (7)):

$$AR_{r_b,h,t} = \overline{g}_{r_b,t} - g_{r_b,t} \tag{6}$$

$$AF_{r_b,h,t} = \overline{g}_{r_b,t} + g_{r_b,t} \tag{7}$$

3.1.5. System-wide

At time t, the total reserves and footroom that can be made available to the system within the horizon h are given by Eq. (8) and Eq. (9), respectively:

$$AR_{h,t} = \sum_{r_c \in \mathcal{R}_c} (AR^{OFF}_{r_c,h,t} + AR^{ON}_{r_c,h,t}) + \sum_{r_v \in \mathcal{R}_v} AR_{r_v,h,t} + \sum_{r_b \in \mathcal{R}_b} AR_{r_b,h,t} \tag{8}$$

$$AF_{h,t} = \sum_{r_c \in \mathcal{R}_c} AF^{ON}_{r_c,h,t} + \sum_{r_v \in \mathcal{R}_v} AF_{r_v,h,t} + \sum_{r_b \in \mathcal{R}_b} AF_{r_b,h,t} \tag{9}$$

These equations are used to calculate system available reserves and footroom for all reserve horizons of interest ($h \in \mathcal{H}$) across all of the dispatch intervals in a given scenario year ($t \in \mathcal{T}$).

4. Case study: Two regions in the National Electricity Market

4.1. Scenarios

In this study, available reserves and footroom were quantified for NSW and SA in calendar year 2020 and for two resource mix scenarios in 2025 (see Table 1). The 2025 scenarios roughly correspond to the Central and Step Change scenarios in AEMO's 2020 Integrated System Plan (ISP) (Australian Energy Market Operator, 2020a), a least-regrets transmission planning study that incorporates scenario-based capacity expansion modelling (Australian Energy Market Operator, 2020d).[4]

[4] The 2022 ISP was recently released (Australian Energy Market Operator, 2022a). For the planning horizon relevant to this study (i.e. to 2025), the 2022 ISP broadly reflects the outlook of its predecessor, with the exception that it draws on extensive consultation with electricity industry stakeholders in determining the Step Change scenario to be the most likely scenario.

Table 1
Scenarios simulated for NSW and SA.

Scenario	Description
2020	• Modelled using historical demand and existing resources – Synchronous units (gas-fired) must run for system strength in SA
2025 Central	• Based on existing policy settings at the time of 2020 ISP: – Moderate deployment of VRE and BESS – Distributed solar PV has moderate impact on operational demand – Thermal unit retirements in both states – Large hydropower capacity addition in NSW – Fewer synchronous units must run for system strength in SA
2025 Step Change	• More aggressive transition: – Large deployments of VRE and BESS – Distributed solar PV has greater impact on operational demand – Further thermal unit retirements in NSW – Large hydropower capacity addition in NSW – Fewer synchronous units must run for system strength in SA

Modelling SA and NSW across these three scenarios enables four sensitivities to be explored:

1. **Conventional generation retirement**. For NSW, one coal-fired power station is retired in 2025 Central and two in 2025 Step Change. In SA, four gas-powered steam turbine (Gas-Steam) units and two combined-cycle gas turbine (CCGT) units are retired between 2020 and both 2025 scenarios.
2. **Increasing deployment of VRE and BESS**. Additional VRE and BESS capacity is deployed in both states between 2020 and 2025 Central in AEMO's 2020 ISP. In the 2025 scenarios for both states, a greater quantity of VRE (predominantly solar PV) and BESS is installed in the Step Change scenario than in the Central scenario. The addition of 2 GW hydro generation in NSW by 2025 reflects the expansion of the region's largest hydro scheme (Snowy 2.0). The capacity mix of each state in 2020 and the changes in the mix for each 2025 scenario are shown in Fig. 2.
3. **Contrast in resource mix and thus operational constraints**. In NSW in 2020, coal-fired generation is a large proportion of the generation fleet and is complemented by hydro generation, gas-fired generation (CCGTs and OCGTs) and VRE. In SA in 2020, VRE (especially wind) is a significant portion of the region's generation fleet. SA's synchronous generation consists of gas-fired generation across the flexibility spectrum, some of which must remain online to ensure there is sufficient system strength in SA for secure operation.
4. **Greater variability in operational demand due to more distributed solar PV**. Operational demand is defined as the system demand that AEMO dispatches resources to meet (i.e. excluding demand met by DER). As the capacity of distributed solar PV in each region increases (i.e. from 2020 to 2025 Central to 2025 Step Change), operational demand in the middle of the day is eroded whilst ramping requirements in the morning (downwards) but especially the evening (upwards) increase. In other words, higher penetrations of distributed solar PV leads to a "deeper" duck curve (Australian Energy Market Operator, 2020h).

4.2. Methodology

For each region and scenario, the available reserves and footroom in the system were calculated from the results of a year-long time-sequential market simulation implemented in the commercial electricity market modelling tool PLEXOS (Energy Exemplar, 2021). The PLEXOS market simulation consisted of a PASA phase to model maintenance and forced outages for conventional generation across the year, a Medium Term Schedule phase in NSW to schedule hydro generation according to monthly energy constraints, and a Short Term Schedule phase that carries out unit commitment and economic dispatch (UC-ED) at 5-minute resolution in daily steps.[5]

Each existing coal-fired (NSW) and Gas-Steam (SA) unit was explicitly modelled to accurately capture the consequences of partial and full outages of large capacity units. For other resource types, the operational constraints and attributes of individual units were averaged and applied across all units of a resource type. This enabled clustered UC-ED and thus reduced the computational burden of the Short Term Schedule phase (Palmintier and Webster, 2014). For baseload conventional generation and gas turbines, ramp rates in each direction were separated into a *market* ramp rate, which was used in the PLEXOS market simulation, and an *upper* ramp rate, which was used to calculate available reserves/footroom (Section 3.1.2). A lower magnitude ramp rate in the market simulation (*market*) reflects participants' preferences to reduce cycling wear-and-tear due to demanding ramping during typical operation (especially for ageing assets) (Kumar et al., 2012), whilst using a higher magnitude ramp rate to calculate a resource's available reserves and footroom (*upper*) ensures that the total available flexibility of a resource can be utilised if needed in a system emergency.

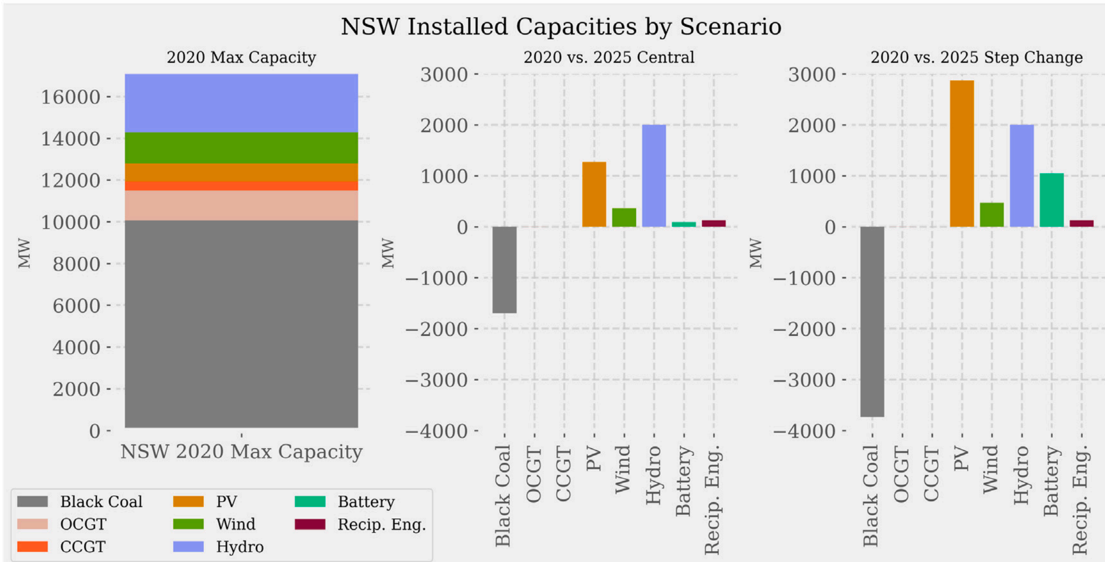
Both NSW and SA were modelled assuming a copper-plate network with no interconnection to other regions (i.e. single bus with no network constraints). The Short Term Schedule mixed-integer linear program was solved using the CPLEX Optimizer (IBM, 2021) with a relative mixed-integer program gap tolerance of 0.07%. The generation and synchronisation status of each resource was obtained from the solution and used to calculate the available reserves and footroom for each 5-minute interval using the equations outlined in Section 3. A process flow diagram of the study methodology is shown in Fig. 3.

In Appendix, we outline our sources for key input data and assumptions (top row of Fig. 3) and provide further details regarding how these data were used in the market simulation and/or the calculation of available reserves and footroom.

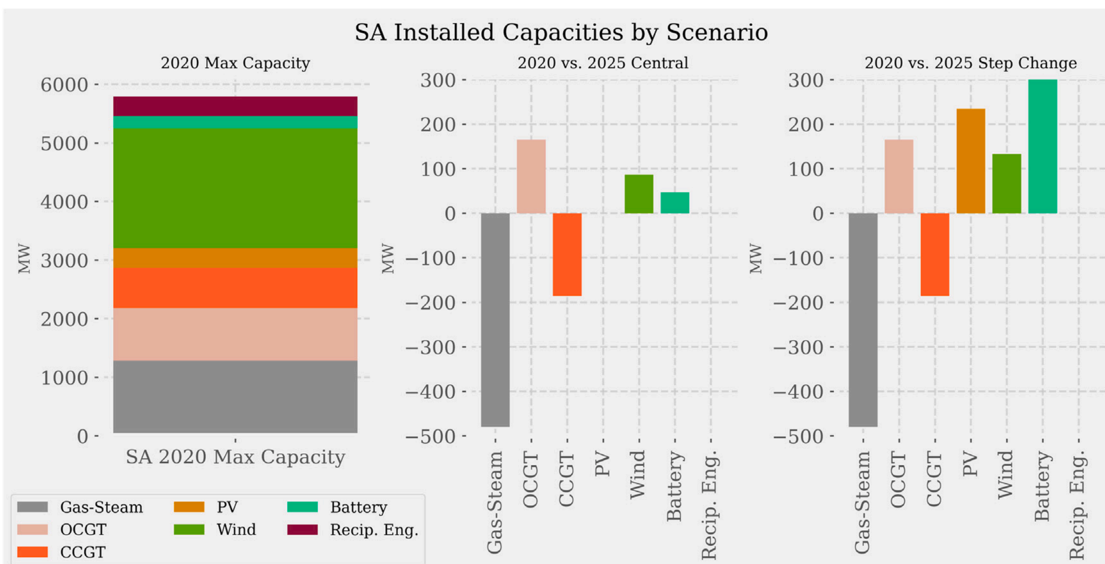
4.3. Limitations

There are two important caveats to this study. The first is that this study models each region in isolation — that is, resources in other NEM regions can neither assist in meeting demand nor provide available reserves or footroom through cross-regional interconnectors. During typical operating conditions, it is likely that any headroom/footroom on interconnectors would mean that a greater quantity of reserves/footroom are available to a region, albeit at different horizons due to modified dispatch patterns. For example, the inclusion of interconnectors in the

[5] A 12 h look-ahead was used in the SA model to avoid "end-of-horizon effects" (Barrows et al., 2020), such as end-of-day decommitment of gas-fired generation.



(a)



(b)

Fig. 2. Capacity mix in NSW (a) and SA (b) in 2020, and additional deployments and retirements in 2025 Central and 2025 Step Change. 2020 resource mixes were adapted from AEMO's 2020 Inputs and Assumptions workbook (Australian Energy Market Operator, 2020c). 2025 scenario resource mixes were aligned with their namesake ISP scenarios (Australian Energy Market Operator, 2020a) and include committed generation (projects that are highly likely to proceed as they have acquired land, secured financing, set a firm construction commencement date and either finalised contracts for components or been granted planning approval) (Australian Energy Market Operator, 2022b).

SA model between SA and VIC and SA and NSW[6] may increase the total available reserves/footroom in SA at the cost of a decrease in the reserves/footroom available within shorter horizons. This could arise from local mid-merit gas generators remaining offline in favour of inflexible but cheaper coal-fired generation in NSW and VIC.

However, modelling available reserves and footroom for isolated regions may provide a closer approximation to reality when balancing flexibility is scarce in a region. Under these circumstances, it is likely that interconnector flows will already be close to their limits. This will reduce or altogether prevent the available reserves/footroom provision from resources in neighbouring regions. Moreover, large interconnector flows may be prevented if there is a credible risk of regional separation (loss of synchronism between market regions due to interconnector circuit faults — a particular risk in the NEM due to limited interconnection between market regions); at present, AEMO co-optimises interconnector flow with regional FCAS procurement (Australian Energy Market Operator, 2010). An additional consideration is that if an operating reserve product is implemented to improve the NEM's resilience to supply–demand shocks, regional procurement requirements may also limit the available reserves/footroom that can be procured over an interconnector. As such, the modelling of isolated regions may approximate actual operation when reserves/footroom are scarce and thus most valuable to the system.

The second caveat is that this study does not explicitly model FCAS procurement. If headroom or footroom reserved for FCAS is

[6] At the time of writing, the interconnector between SA and NSW is under construction and due to commence operation in 2025/2026 (ElectraNet, Transgrid, 2022).

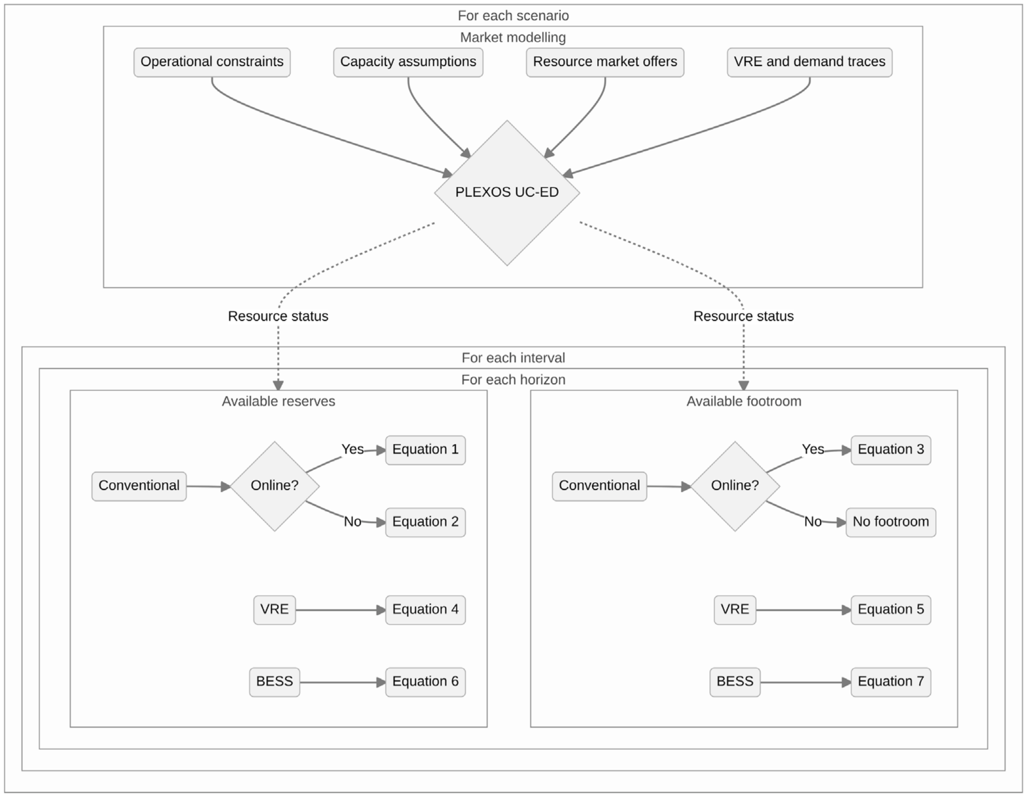


Fig. 3. Process flow for modelling available reserves and footroom for each scenario in this case study.

unable to also provide available reserves or footroom,[7] then modelling FCAS markets would reduce the reserves and footroom that are available within horizons less than or equal to 5 min. However, the actual headroom/footroom reduction would depend upon the following factors:

- Whether regional FCAS procurement constraints bind for the modelled region. If they do not, multi-regional or NEM-wide FCAS requirements can be satisfied by procuring FCAS in other market regions.
- The degree to which headroom/footroom is "re-offered" across sequential FCAS markets. For example, a single resource enabled for 10 MW across the three raise contingency FCAS markets would withdraw less system headroom than three resources enabled for 10 MW each for a particular FCAS market.
- Headroom that is offered into the 6 s and 60 s raise contingency FCAS market may not reflect sustained power provision. For example, frequency response from a steam-powered turbine may draw on steam stored in a boiler; a sustained response would require a longer timeframe due to slower boiler dynamics.

4.4. Results and discussion

4.4.1. Synthetic daily profiles

Synthetic daily profiles (SDPs) were developed to quantify the time-varying spectrum of available reserves and footroom for each scenario. For a given horizon, the SDP value at a particular time is an aggregate value (mean or a specific percentile) calculated from the reserves/footroom available within that horizon at the end of that dispatch interval across all days in the simulated year. In other words, values from across the year for a given time of day are aggregated, and these are then "stitched" together to form a "synthetic day" curve for a particular horizon. Two aggregate values were calculated for each horizon curve:

1. The mean. This provides a picture of the average or "typical" availability of reserves and footroom at different times of the day for a particular scenario year; and
2. The bottom 1% (i.e. 1st percentile or 1-in-100 day lowest). This measure better reflects the availability of reserves and footroom when they are scarce and thus when they are most needed.[8]

In addition to an infinite horizon (which corresponds to the maximum availability), curves were calculated for 1, 5, 15, 30 and 60 min horizons. These horizons encompass the start-up times of hydro and flexible gas generation, and represent the likely timeframes over which the proposed operating reserve product will be required to respond.

4.4.2. Available reserve synthetic days

Mean and bottom 1% available reserve SDPs were generated for the NSW scenarios and for the SA scenarios (Figs. 4, 5). The mean SDPs across scenarios suggest that, on average, NSW has more than 2 GW and SA more than 600 MW of reserves available within 5+ min. These levels of reserves:

[7] Exclusive headroom procurement for an operating reserve service (i.e. inability to offer the same headroom in FCAS markets) is currently being considered (Energy Security Board, 2021).

[8] More extreme percentiles (i.e. < 1%) could better reflect the tight reliability standards adopted in many power systems - e.g. the NEM standard of a maximum expected unserved energy of 0.002% of the total energy demand of a NEM region in an Australian financial year (Australian Energy Market Commission Reliability Panel, 2022). However, the use of extreme percentiles would be more appropriate with a greater number of modelled days (i.e. several years).

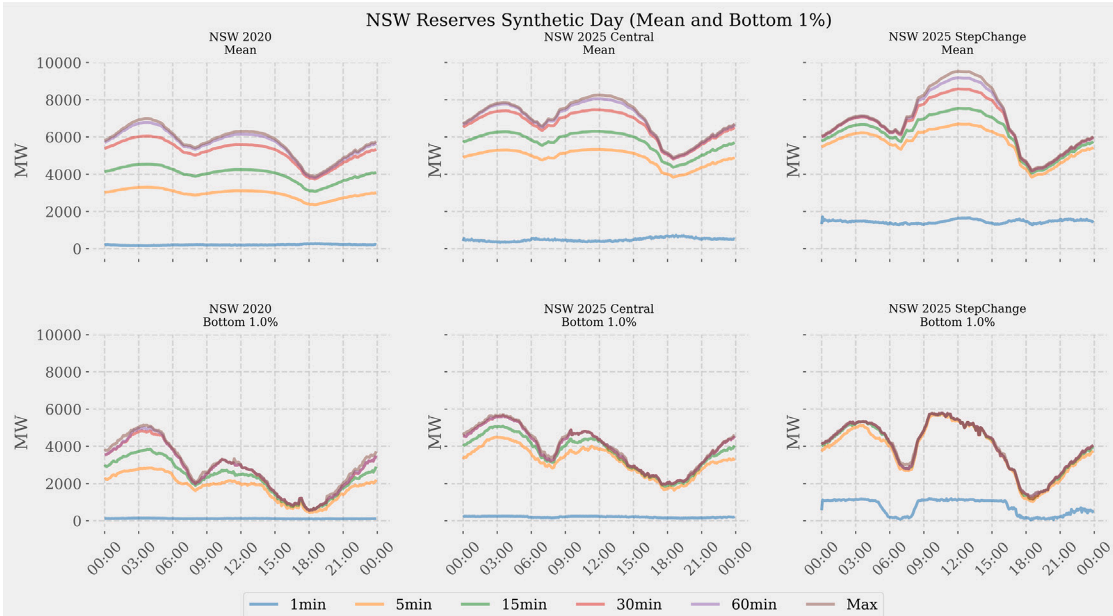


Fig. 4. Mean (top row) and bottom 1% (bottom row) SDPs for available reserves in NSW in 2020 (leftmost column) and the two 2025 scenarios (rightmost columns).

1. Correspond to approximately 15% and 20% of peak demand in 2020 in NSW and SA, respectively. These 5+ min "reserve margins" (i.e. 5+ min reserves as a percentage of peak demand) are comparable to lower-end reserve margins anticipated for the summer of 2022 in North American jurisdictions (North American Electric Reliability Corporation, 2022).
2. Exceed the highest N-1 contingency in 2020 (i.e. highest LOR2 trigger level declared in the last run of Pre-Dispatch PASA prior to delivery — see Section 2.2) by approximately 225% in NSW and 170% in SA (Prakash, 2022).

Furthermore, with additional BESS and flexible gas resources expected to be deployed, the mean 5+ min reserve margins of both regions are higher for most parts of the day in the 2025 Step Change scenario. Though the market simulation relied on perfect foresight (additional uncertainty may reduce reserve margins), these results suggest that reasonable quantities of reserves are available in each region within a 5+ min horizon.

Across scenarios, the following trends are apparent in the SDPs:

1. From 2020 to the 2025 Step Change scenario, a midday peak in the mean available reserves SDPs becomes more pronounced. This can be attributed to the increasing displacement of conventional generation by lower-cost utility-scale solar PV in dispatch (an outcome observed by Hummon et al. (2013) and Tanoto et al. (2021)) and the progressive erosion of daytime operational demand due to higher penetrations of distributed solar PV. Particularly in SA, curtailed VRE and BESS also contribute to this reserve "surplus". BESS in particular are often charging during such periods of plentiful supply and low prices, and thus are able to offer up to double their active power rating as reserve (i.e. by switching from charging to discharging).
2. As is particularly clear in the bottom 1% SDPs for the 2025 scenarios, the availabilities of different reserve horizons tend to converge during periods of lower reserves or "relative scarcity", which include peak demand events in the morning and evening. The convergence may be driven by the retirement of baseload conventional generation and higher ramping requirements in the 2025 scenarios requiring more flexible, mid-merit resources to be online prior to and during these periods.

From this analysis, we can also gain an insight into the supply-side dynamics of a potential operating reserve product market. The first trend suggests that as energy transition proceeds, a reserve surplus during the daytime could suppress the price of an operating reserve product (a dynamic that is further explored by Frew et al. (2021)). Moreover, the convergence of availability across horizons during periods of "relative scarcity" suggests that relatively inflexible but cheaper resources are being preferentially ramped through dispatch at these times whilst more flexible but expensive resources are left in reserve. Since the majority of system headroom during these periods appears to be available within 5 to 15 min, operating reserves would likely be procured from these more flexible resources regardless of whether the product requires availability within 5 or 30 min. As such, concerns regarding limited providers of a 5-minute horizon product may also apply to a 30-minute horizon product during periods of relative scarcity (noting that several resource types in the NEM are already providing upwards flexibility within 5 min in the NEM, as shown in Fig. 1).

4.4.3. Available footroom synthetic days

Two types of SDPs were constructed for available footroom: one for *firm* footroom and the other for total footroom. The former refers to potential footroom provision from conventional resources and BESS, whereas the latter also includes footroom that can be provided by curtailing VRE. Figs. 6, 7 show mean and bottom 1% SDPs across NSW scenarios for firm footroom and total footroom, respectively. From the bottom 1% SDPs in Fig. 6, it is clear that firm system footroom can become very low in NSW in 2025 as remaining baseload conventional generators are driven to operate closer to their MSLs. However, such concerns could be alleviated if VRE provide footroom (Fig. 7). A similar result was observed for the SA region.

The available footroom in the system is likely sensitive to extent of conventional generation retirements. Further retirements may enable remaining conventional resources to operate at a higher loading, thereby increasing the available footroom in the system. Regardless, given that each region appears to suffer a lack of *firm* footroom for several hours during the day in the 2025 scenarios explored in this case study, mechanisms for procuring sustained downwards balancing flexibility should be considered alongside those for procuring sustained upwards balancing flexibility. One simple option would be to implement an operating *footroom* product, which, if VRE are permitted to

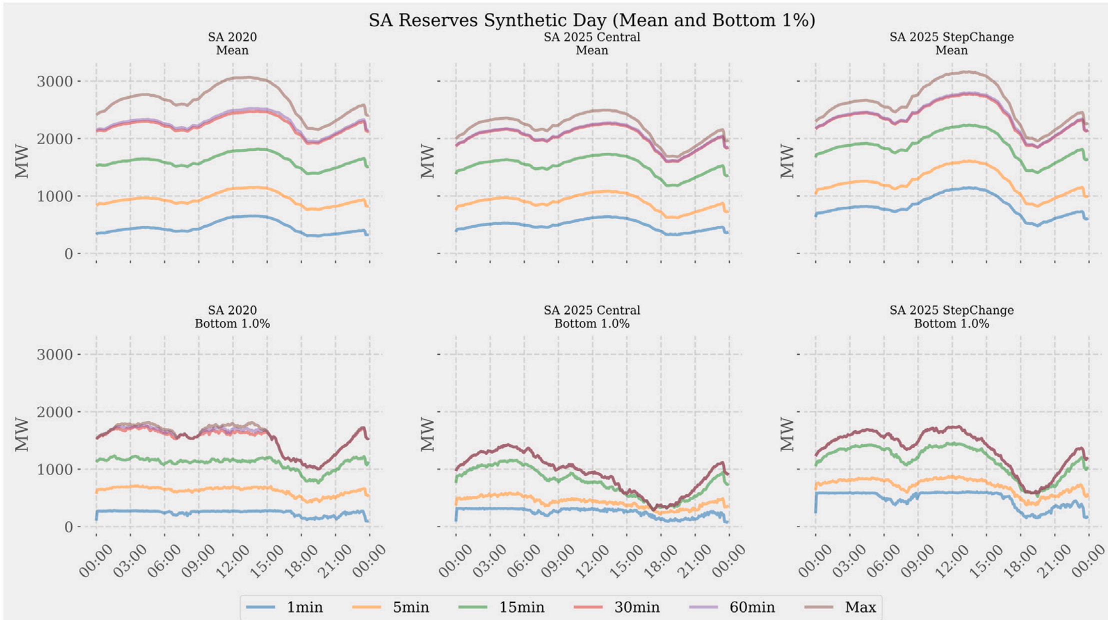


Fig. 5. Mean (top row) and bottom 1% (bottom row) SDPs for available reserves in SA in 2020 (leftmost column) and the two 2025 scenarios (rightmost columns).

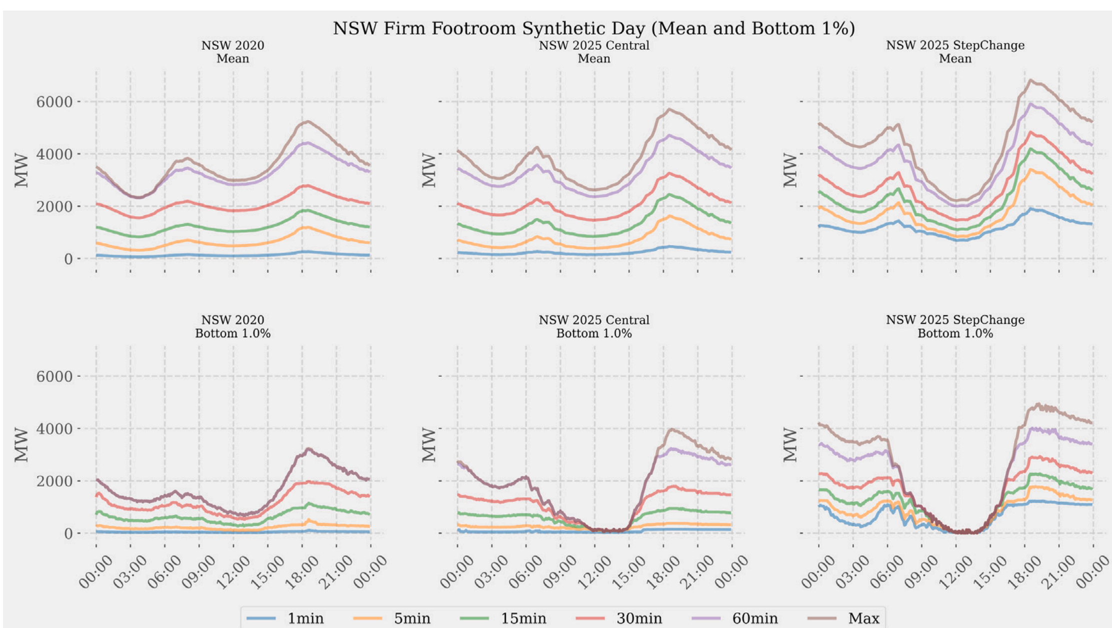


Fig. 6. Mean (top row) and bottom 1% (bottom row) SDPs for available firm footroom (i.e. footroom provided only by "firm" resources: conventional and BESS) in NSW in 2020 (leftmost column) and the two 2025 scenarios (rightmost columns).

provide this service, can enable conventional generation to operate closer to their MSL and thus reduce system operating costs and carbon emissions (Nelson et al., 2018).

4.4.4. Short-term energy-limited reserves

While the available reserves metric does not consider the duration for which reserve deployment can be sustained, we can infer whether reserves are short-term energy-limited (i.e. with a duration no more than a few hours) based on their resource type. For this analysis, BESS reserve power was calculated based on the BESS's state of charge at the end of each dispatch interval and the requirement to sustain provision for 15 min. This duration is consistent with the BESS power and capacity that is reserved in SA for the possibility of loss of interconnection (Australian Energy Market Operator, 2020e). In addition, the maximum available price-responsive demand available in each state was added to the available reserves in each dispatch interval (assuming an emergency response time of 5 min) to gain a better understanding of the maximum potential contribution of demand response. This corresponded to ∼60 MW in SA and ∼290 MW in NSW, based on AEMO analysis and forecasts in Australian Energy Market Operator (2020c). Both BESS and DR can be considered to be short-term energy-limited reserve providers. Though conventional generation fuel constraints (e.g reservoir schemes and the gas system) were not modelled in this market simulation, the contribution of conventional resources was separated into those of thermal and hydro to assess the importance of the energy constraints on each resource type to available reserves in NSW.

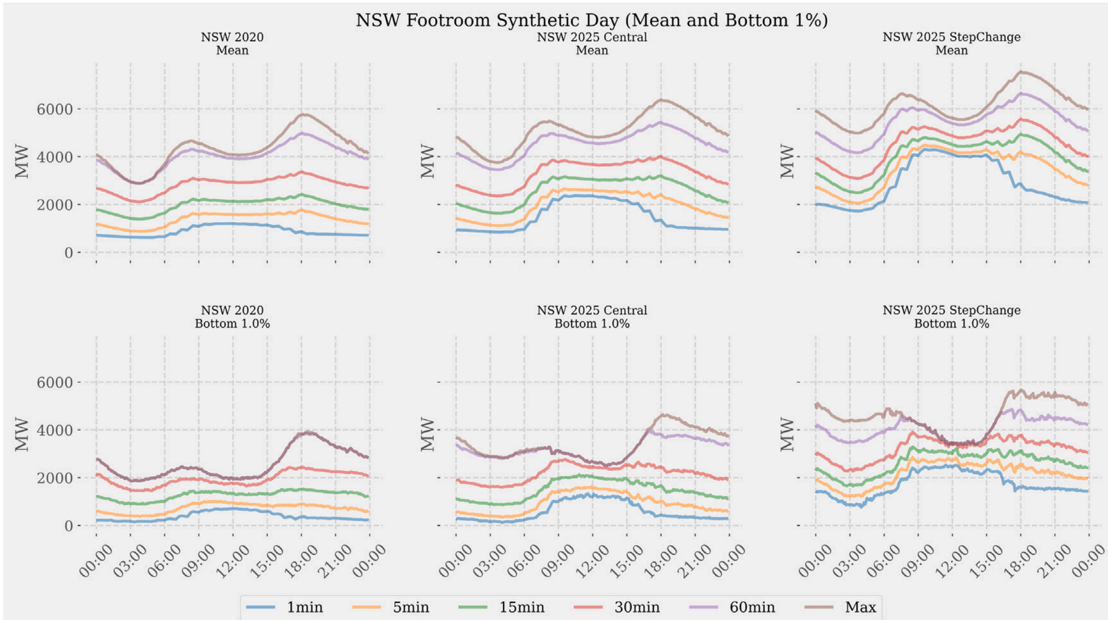


Fig. 7. Mean (top row) and bottom 1% (bottom row) SDPs for available total footroom (including footroom that would be provided by curtailing VRE) in NSW in 2020 (leftmost column) and the two 2025 scenarios (rightmost columns).

Tables 2 and 3 show the median percentage across dispatch intervals in a scenario year of available reserves provided by a resources type for NSW and SA, respectively. Whilst hydro and thermal resources dominate 5 min horizon reserve provision in 2020 in NSW and SA, respectively, short-term energy limited resources provide a greater proportion of reserves in this horizon in 2025. In particular, the median contribution of BESS to reserves available within 5 min is 16% for NSW and 40% for SA in the 2025 Step Change scenario. As the reserve horizon is extended to 30 min, a greater proportion of reserves are provided by conventional resources, which may be better positioned to sustain a response beyond the short-term.[9] These results indicate that as energy transition progresses, a trade-off between reserve deployment speed and duration develops. This trend reaffirms the value of the sequential and hierarchical approach to reserve product design and deployment that has been adopted in many jurisdictions (Prakash et al., 2022). Moreover, it should be noted that unlike other mechanisms for procuring balancing flexibility, reserve services and products can specify duration/energy requirements and thus ensure that flexibility provision is sustained.

4.5. The role of balancing products

It is unclear whether introducing an operating reserve product will deliver material operational benefits to the NEM in light of the revenue risks, complexity, and implementation and ongoing costs associated with a new market. Instead, existing mechanisms may be able to deliver sufficient upwards flexibility, particularly if they can be augmented:

1. Market participants with forward market obligations are strongly incentivised to offer balancing flexibility to the market. The premium payment offered to the seller, along with a strong financial incentive to perform during periods of system stress, means that derivatives such as cap contracts somewhat resemble pay-for-performance capacity remuneration mechanisms.[10] Participants would have further incentive if contracting were made mandatory (Mays et al., 2022), or if they increasingly resort to contracting to hedge pricing volatility that could occur as energy transition progresses (de Vries and Jimenez, 2022).

Table 2
Median of the percentage of each resource type's contribution to reserves available within 5 min and 30 min in every dispatch interval for each NSW scenario year. The median percentages are not necessarily coincident (i.e. from the same dispatch interval) and therefore may not sum to 100%. Furthermore, some distributions are long-tailed, so a median does not capture occasional reserve provision by a resource type (e.g. VRE, for which all medians are 0%).

NSW resources	2020		2025 Central		2025 Step Change	
	5 min	30 min	5 min	30 min	5 min	30 min
BESS (15 min)	0%	0%	2%	1%	16%	14%
DR	9%	5%	5%	4%	5%	4%
Hydro	74%	43%	81%	60%	71%	61%
Thermal	18%	52%	12%	34%	8%	19%

Table 3
Median of the percentage of each resource type's contribution to reserves available within 5 min and 30 min in every dispatch interval for each SA scenario year. The median percentages are not necessarily coincident (i.e. from the same dispatch interval) and therefore may not sum to 100%. Furthermore, some distributions are long-tailed, so a median does not capture occasional reserve provision by a resource type (e.g. VRE, for which all medians are 0%).

SA resources	2020		2025 Central		2025 Step Change	
	5 min	30 min	5 min	30 min	5 min	30 min
BESS (15 min)	14%	6%	24%	10%	40%	20%
DR	7%	3%	7%	3%	5%	3%
Thermal	71%	88%	61%	84%	45%	73%

[9] In reality, conventional resources are also susceptible to fuel constraints, as highlighted by the events preceding the 2022 NEM suspension (Australian Energy Market Operator, 2022c). More sophisticated modelling of thermal coal availability, the gas system and hydro schemes, including their operation under different climate conditions, would be required to better understand the potential duration of available reserve provided by conventional generation.

[10] However, derivatives are financial in nature and thus need not be "backed" by power system resources (i.e. they are not associated with any physical obligation).

2. Market and system information and forecasts (e.g. the NEM's ahead processes) may be critical to ensuring that market participants schedule resources to provide flexibility to the system. Future work should not only seek to improve their accuracy and their treatment of uncertainties, but also to understand how they shape participant decision-making and thus which enhancements could provide the most value.

However, there remain some operational benefits of additional balancing products. Nested distribution-level markets and/or real-time market scheduling of aggregated resources have the potential to better enable balancing flexibility from DER. However, a key insight from Section 4.4.4 is that consideration should be given to the duration of this flexibility. System stress could coincide with periods in which DER owners wish to use these resources for themselves (e.g. a heatwave or if they are exposed to real-time market volatility to some extent) (Roberts et al., 2020). In contrast, reserve products that specify response durations could provide the SO with certainty that flexibility is only procured from resources that are available for a minimum period of time. Any duration requirements would need to be balanced against the quantity and diversity of flexibility providers — primarily to ensure that product markets are competitive, but also because successive deployment of several short-term energy limited resources may be sufficient to meet system balancing needs over the course of a few hours. Furthermore, sustained footroom products might assist SOs in managing a lack of firm footroom (Section 4.4.3). Typically, energy prices rise when upwards flexibility is scarce, thereby compensating providers of upward flexibility. In contrast, downwards flexibility providers are not strictly compensated through energy pricing, as oversupply could lead to dispatch curtailing, rather than remunerating flexible resources. Though this might mean flexible resources avoid financial losses, it comes at the cost of footroom available to the system. Accordingly, an "operating footroom" product that remunerates downwards flexibility offers a solution to the tension between dispatch incentives and the need for system footroom.

5. Conclusion and policy implications

State-of-the-art resource adequacy assessments are closing the gap between traditional capacity adequacy assessments, which focus on capacity reserve margins during peak demand events, and flexibility adequacy assessments that often model chronological operations (Stenclik et al., 2021). Yet flexibility adequacy assessments alone do not necessarily offer a better understanding of *what type* of balancing flexibility a system has and might need, and *how* best to make it available to the system. As resource mixes change dramatically during energy transition, system designers, planners and operators should quantify balancing flexibility capabilities to gain an appreciation of the availability of different resource types to inform operational practice design.

By quantifying balancing flexibility "margins" in two sub-systems of the Australian National Electricity Market (Section 4), we identify potential balancing flexibility dynamics and trends in future power systems. Firstly, systems with high penetrations of distributed and utility-scale solar PV will likely have reserve "surpluses" around the middle of the day and periods of relative reserve scarcity during morning and evening peak demand events. In such systems, the periods when reserves are most valuable do not necessarily correspond to the periods during which it is most efficient to curtail renewable energy generation (due to oversupply or to obtain reserves). As such, a key recommendation for policy-makers is to consider whether reserve product markets are needed to elicit sufficient balancing flexibility provision during these short periods of relative scarcity, or whether adjusting energy market settings, forward market obligations and/or market and system information processes can achieve this. Understanding the potential benefits of new reserve product markets is crucial because they can introduce additional costs, constraints and complexity whilst encroaching upon the functions of other operational practices. Secondly, our study highlights the importance of placing a greater emphasis on duration, as resources touted as essential future balancing flexibility providers (e.g. battery energy storage, demand response) may only be able to sustain a response for at most a few hours. Thirdly, we highlight the need to consider footroom and the benefits of enabling renewable energy to provide it. Footroom procurement and response duration specifications are underappreciated by prevailing market designs, and may be better addressed by policy-makers either modifying existing or creating new reserve product specifications.

CRediT authorship contribution statement

Abhijith Prakash: Conceptualization, Methodology, Software, Data curation, Formal analysis, Visualization, Writing – original draft, Writing – review & editing. **Rohan Ashby:** Conceptualization, Methodology, Software, Data curation, Formal analysis, Visualization, Writing – review & editing. **Anna Bruce:** Conceptualization, Methodology, Validation, Resources, Writing – review & editing, Supervision, Project administration. **Iain MacGill:** Conceptualization, Methodology, Validation, Resources, Writing – review & editing, Supervision, Project administration.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

Data will be made available on request

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Appendix. Data and assumptions used in market simulation

A.1. Resource ramp rates

Separate upwards and downwards ramp rates were modelled for most resource types. For hydro generation and reciprocating engines, maximum upwards and downwards ramp rates were sourced from GHD (2018). For other conventional resources (coal-fired generation, Gas-Steam, CCGT and OCGT), ramp rates in each direction were further separated into a *market* ramp rate, which was used in the PLEXOS market simulation, and an *upper* ramp rate, which was used to calculate available reserves/footroom (Section 3.1.2). For these resources, the market ramp rate was calculated using the unit ramp rates used most

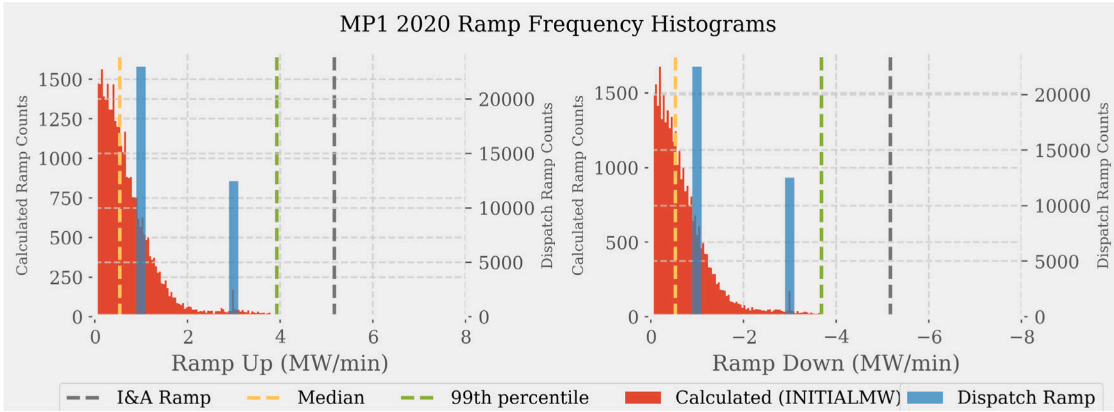

Fig. A.1. Ramp rates observed (red) and used in dispatch by AEMO (blue) for a coal-fired unit in NSW in 2020. The green line denotes the ramp rate assumed by AEMO in its 2020 Inputs and Assumptions workbook and the 2020 ISP. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

frequently in NEM dispatch[11] in 2020, and the upper ramp rate was calculated using resources' assumed maximum ramp rates in AEMO's 2020 Inputs and Assumptions workbook (for an example of a comparison, see Fig. A.1) (Australian Energy Market Operator, 2020c). Additional resources in 2025 were assumed to have the same ramp rate characteristics as newer existing resources of the same technology type.

A.2. Unit commitment and cycling constraints

Many existing flexible conventional resources (OCGT, reciprocating engines and hydro generation) submit dispatch inflexibility profiles to AEMO that contain the resource's time to start up and reach MSL, the MSL itself, the time required at minimum loading and the time taken to shut down (Australian Energy Market Operator, 2021b). The most frequently offered fast start inflexibility profile of a resource in 2020 was obtained using NEMOSIS (Gorman et al., 2018) and used to calculate its start-up rate, minimum up-time, MSL and shutdown rate. The minimum down-time for these resources was chosen to be equal to the minimum up-time.

For the other conventional resources (CCGT, coal-fired generation and Gas-Steam), minimum up-times, minimum down-times and MSLs were obtained from AEMO's 2020 Inputs and Assumptions workbook (Australian Energy Market Operator, 2020c) and start-up rates were calculated based on hot or warm start times (i.e. depending on the start state of the resource after being offline for its minimum down-time) obtained from GHD (2018) or Aurecon Australasia (2020). The shut-down rates for these resources were calculated based on actual shutdowns, or those of similar technology types, observed in AEMO dispatch data that was obtained using NEMOSIS (Gorman et al., 2018).

BESS were dispatched by PLEXOS's arbitrage algorithm subject to charging and discharging efficiencies and maximum and minimum state of charge constraints that corresponded to those assumed within AEMO's 2020 Inputs and Assumptions workbook (Australian Energy Market Operator, 2020c). Given an assumed economic lifetime of 10 years (Australian Energy Market Operator, 2020c) and 3000 cycles (da Silva Lima et al., 2021) for lithium-ion BESS, a constraint of 300 cycles per year was applied to BESS in each scenario.

[11] The ramp rate used in dispatch by AEMO is the lesser of a telemetered rate or a ramp rate submitted in a resource's offer for energy, and was obtained using NEMOSIS (Gorman et al., 2018).

A.3. Partial and forced outages

Maintenance rates, forced outage rates (partial and full) and the corresponding mean time taken to repair were modelled for all conventional generation and were sourced from AEMO's 2020 Inputs and Assumptions workbook (Australian Energy Market Operator, 2020c).

A.4. SA synchronous generation requirement

At present, certain combinations of synchronous generators are required to remain online for power system security in SA. Should ahead processes indicate that the synchronous generation expected to be online and dispatched is inadequate to provide sufficient system strength in SA, AEMO will intervene in the market and direct additional synchronous generation online (Gu et al., 2019). The various sufficient combinations of synchronous generation in SA are outlined in Australian Energy Market Operator (2022d), with a decrease in requirements/increase in the allowable asynchronous generation level following the installation of 4 synchronous condensers (completed in 2021). To model these requirements, a must-run condition was imposed on 3 CCGT units and 1 Gas-Steam unit in 2020, and on 2 CCGT units and 1 Gas-Steam unit in the 2025 scenarios. These combinations reflect a subset of the sufficient combinations outlined in Australian Energy Market Operator (2022d).

A.5. Hydro generation monthly energy constraints

Run-of-river hydro generation and pumped hydro storage in NSW were aggregated and modelled as dispatchable generation with monthly energy constraints. These monthly energy constraints correspond to the average monthly inflows for the Snowy scheme (NSW and Australia's largest hydro scheme) across financial years 2011 to 2018 (obtained from Australian Energy Market Operator (2020c)). Though this model for hydro does not account for the additional generation that could be extracted from pumped storage, the application of monthly energy constraints could be interpreted as modelling one pattern of run-of-river hydro operation and/or enforcing the same reservoir level at the start and end of each month (and thus at the start and end of each year). Explicitly modelling reservoir schemes, inflows for individual hydro generators and pumping opportunities for pumped hydro storage are likely to improve the accuracy of the methodology proposed in this work for systems with significant shares of hydropower capacity.

Table A.1
Offers by resources type for NSW and SA across all scenarios. The market floor and cap prices used were −1000 AUD/MW/hr and 15,000 AUD/MW/hr, respectively.

Generator type	Price band 1 (AUD/MWh)	Price band 2 (AUD/MWh)	Price band 3 (AUD/MWh)	Price band 4 (AUD/MWh)
Coal	Floor	30	50	Cap
CCGT	40/Floor (NSW/SA)	70	170	–
OCGT	100/175 (NSW/SA)	200/300 (NSW/SA)	500	Cap
Reciprocating engine	175	300	500	Cap
Gas-Steam	Floor	90	190	Cap
Wind	Floor	–	–	–
Solar PV	Floor	–	–	–
Hydro	35	60	300	Cap

Table A.2
Percentage of annual generation by resource type for the simulated NSW 2020 scenario and for NSW in 2020 (calculated based on historical data obtained using NEMOSIS (Gorman et al., 2018)).

	Coal	Wind	Hydro	Solar PV	CCGT	OCGT
NSW 2020	82.9%	6.4%	4.5%	3.2%	2.4%	0.6%
Historical 2020	84.5%	6.6%	3.8%	3.3%	1.5%	0.3%

Table A.3
Percentage of annual generation by resource type for the simulated SA 2020 scenario and for SA in 2020 (calculated based on historical data obtained using NEMOSIS (Gorman et al., 2018)). Note that percentages may not sum to a total of 100% due to net storage in BESS.

	Wind	CCGT	Gas-Steam	Solar PV	OCGT	Reciprocating engine
SA 2020	45.6%	25.6%	16.8%	8.0%	2.3%	1.6%
Historical 2020	43.7%	29.7%	15.1%	5.1%	2.3%	3.5%

A.6. Demand and VRE traces

Chronological demand traces at 5-minute resolution were used in the market simulation. For each region, historical operational demand for 2020 at 5-minute resolution was obtained using NEMOSIS (Gorman et al., 2018) and used as the demand trace for the 2020 scenario. AEMO ISP demand traces were available for each 2025 scenario at half-hourly resolution (Australian Energy Market Operator, 2019b); 5-minute resolution demand traces for each 2025 scenario were produced by scaling 5-minute historical operational demand by a corresponding half-hourly scaling factor, which was calculated as the ratio of the ISP scenario's 2025 demand trace to the ISP scenario's 2020 demand trace.

Half-hourly chronological solar PV and wind capacity factor traces were obtained from AEMO's ISP database for each 2020 scenario (Australian Energy Market Operator, 2019a) and for each 2025 scenario (Australian Energy Market Operator, 2020b). Generation traces were obtained by multiplying the capacity factor trace of a resource by its nameplate capacity. Capacities for existing and committed VRE plants were obtained from AEMO's 2020 Inputs and Assumptions workbook (Australian Energy Market Operator, 2020c) and any additional VRE capacity that was built out in the 2025 scenarios was assigned to AEMO-designated Renewable Energy Zones (for which capacity factor traces are available) based on the ISP's generation capacity outlook. The half-hourly generation traces for each resource and Renewable Energy Zone in a region were than aggregated and linearly interpolated for use in the 5-minute resolution market simulation.

A.7. Resource market offers

For all scenarios for a given region, one set of four static price-quantity pairs were used to represent each resource's offer in the market simulation. Except for hydro generation, offers were priced *a priori*. The type of the resource determined how each band was priced (price bands for each resource type are outlined in Table A.1)[12]:

- For wind and solar PV generators, the entire available forecasted energy was offered at the market floor price to ensure preferential dispatch of VRE where possible.
- For baseload conventional resources (coal-fired generation and Gas-Steam), the first band was priced at or close to the market floor price to ensure the resource's MSL would clear the market. The second band was priced close to the short-run marginal cost (SRMC) of the resource. The SRMC was calculated using the average heat rate, fuel price and variable operating and maintenance cost of each resource type obtained from Australian Energy Market Operator (2020c). The third band was priced at a premium relative to the resource's SRMC and the fourth band was offered at the market cap price.
- For peaking generation (OCGT and reciprocating engines), the first band was priced close to the SRMC of each resource, which was calculated in the same manner as for baseload conventional resources. The second and third band were offered at a moderate and higher premium relative to the resource's SRMC, respectively. The fourth band was offered at the market cap price.
- Hydro generation offers were adjusted iteratively to align the proportions of annual generation and average market prices of the NSW 2020 scenario with those calculated from historical data.

A.7.1. Calibration

Resource offer quantities were used to calibrate the 2020 simulation with historical generation patterns in each state. The quantity of energy in each price band was adjusted in an iterative process of offer adjustment and market simulation to ensure that the proportion of annual generation of a particular resource type in the simulated 2020 scenario was similar to the actual proportion of annual generation for that resource type in 2020. The combination of offer quantities that produced the closest proportions were retained and used for each state's 2020 and 2025 scenarios. The results of the calibration for NSW and SA are outlined in Table A.2 and Table A.3, respectively.

[12] For all conventional resources, the distribution of offer prices resembles "hockey-stick" offer curves that are common in the NEM (Energy Synapse, 2020) and in other electricity markets (Hurlbut et al., 2004). Moreover, for most peaking conventional resources, energy is offered at or just above the strike price of cap options/futures (300 AUD/MWh).

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